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BY E-MAIL

September 29, 2017

Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Cooperative Hydro Embrun Inc. (Cooperative Hydro Embrun)
2018 Distribution Rate Application
OEB Staff Interrogatories
OEB File No.: EB-2017-0035

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

Cooperative Hydro Embrun's responses to interrogatories are due by October 18, 2017.

Yours truly,

Original Signed By

Georgette Vlahos
Advisor – Incentive Rate-setting & Accounting

Attach.

OEB Staff Interrogatories
2018 Cost of Service Rate Application
Cooperative Hydro Embrun Inc. (Cooperative Hydro Embrun)
EB-2017-0035
September 29, 2017

Exhibit 1 – Administration

1-Staff-1
Responses to Letters of Comment

At the community meeting, two consumers provided comments regarding Cooperative Hydro Embrun's application.

Section 2.1.6 of the Filing Requirements state that distributors will be expected to file with the OEB their response to the matters raised within any letters of comment sent to the OEB related to the distributor's application. If the applicant has not received a copy of the letters or comments received at the community meetings, they may be accessed from the public record for this proceeding.

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

1-Staff-2
Ref: Exhibit 1/Business Plan/Section 2.2/Page 6 - Utility Ownership

Cooperative Hydro Embrun is structured as a cooperative utility under the *Cooperative Corporations Act,* and is based on voluntary and open membership with a one-time cost of $10 per member. Each customer is a member and owner of the business with an equal say in decision making. Profits are either reinvested for infrastructure or distributed to members in the form of dividends.

(a) Can one member own multiple shares?
(b) At its Corporate Annual Meeting, please explain how (i.e. in what format) members views are heard in relation to the Cooperative's proposed plans.
(c) Please provide any meeting minutes or reports as available.
(d) Please describe in detail 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.

(e) Please describe the system used in decision making.

1-Staff-3
Ref: Exhibit 1/Business Plan/Section 4.3/Page 10 – Alignment of Goals to Needs and Preferences of Customers

In advance of this application, Cooperative Hydro Embrun notes that it reached out to customers to seek feedback on their views and preferences. Based on this feedback, Cooperative Hydro Embrun is confident that with the communication plan in place, the utility's capital budget supports customer's preferences and priorities.

(a) Please elaborate on the "communication plan in place".
(b) Please provide examples on what type of feedback made Cooperative Hydro Embrun confident about its proposed capital expenditures.
(c) Please provide examples on any of the feedback that supports the proposed OM&A spending for the test year.

1-Staff-4
Ref 1: Exhibit 1/Business Plan/Section 5.1/Page 14 – Past Performance
Ref 2: 2018 Benchmarking Model (PEG)

Table 2 of reference 1 is reproduced below:

	2014	2015	2016
	(History)	**(History)**	**(History)**
Cost Benchmarking Summary			
Actual Total Cost	**1,052,237**	**1,097,457**	**1,119,904**
Predicted Total Cost	**1,415,586**	**1,530,324**	**1,802,737**
Difference	**(363,350)**	**(432,867)**	**(682,833)**
Percentage Difference (Cost Performance)	**-29.7**	**-33.2%**	**-47.6%**
Stretch Factor Cohort - Annual Result	**2**	**1**	**1**

At reference 2, the "Results" tab shows that for 2016 the percentage difference (cost performance) is -25% as opposed to the -47.6% result in the table above.

Please explain the apparent discrepancy.

1-Staff-5
Ref 1: Exhibit 1/Business Plan/Section 8/Page 28 – Financial Results
Ref 2: Exhibit 1/Section 1.10/Page 60 – Financial Information

Financial Ratios

	Liquidity: Current Ratio (Current Assets/Current Liabilities)	Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio	Profitability (Approved ROE)	Regulatory Return on Equity (Achieved ROE)
2011	3.19	0	9.36%	6.26%
2012	3.24	0	9.36%	10.28%
2013	3.14	0	9.36%	8.43%
2014	3.09	0	9.36%	4.35%
2015	2.87		9.36%	1.53%

Cooperative Hydro Embrun notes that its financial performance has remained strong over the past 4 years. By the end of 2017, Cooperative Hydro Embrun will be under-earning mainly due to increases in capital spending and a one-time administrative cost associated with an OEB audit.

Please explain the causes of the significant under earning in 2014 and 2015 and indicate the amount and provide explanation of any one-time events such as those experienced in 2017 which impacted the achieved ROE.

1-Staff-6
Ref: Exhibit 1/Section 1.3.4/Page 10 – Legal Application

At the above reference, it is noted that "this application is made in accordance with the Board's Chapter 2 of the Board's Filing Requirements for Transmission and Distribution Applications dated January 2, 2014."

Please confirm that the above is a typographical error and Cooperative Hydro Embrun followed the OEB's most recent Filing Guidelines applicable at the time of filing (i.e. 2016 edition for 2017 rate applications issued July 14, 2016).

1-Staff-7
Customer Engagement
Ref: Chapter 2 of the Filing Requirements, Section 2.1.6

Please describe the differences between customer engagement conducted in preparation for the current application and previous customer engagement. Please explain how customer engagement has been enhanced.

1-Staff-8
Reflecting Customer Needs
Ref: Chapter 2 of the Filing Requirements

Chapter 2 of the Filing Requirements states, “Distributors should specifically discuss in the application how they informed their customers on the proposals being considered for inclusion in the application, and the value of those proposals to customers (i.e. costs, benefits and the impact on rates). The application should discuss any feedback provided by customers and how this feedback shaped the final application”.

What forms of outreach were employed to explain how the current application serves the needs and expectations of customers? If none were employed, please explain why.

1-Staff-9
Customer Satisfaction Survey
Ref: Exhibit 1/Section 1.7.2/Pages 52-54

Cooperative Hydro Embrun, through a collaborative effort with Hearst Power Distribution Company Limited, Hydro Hawkesbury Inc., Hydro 2000 Inc., and Chapleau Public Utilities, developed an in-house customer satisfaction survey in order to minimize the cost of the survey and to share intellect and resources.

(a) Please indicate the number of respondents to the survey specific to Cooperative Hydro Embrun.
(b) Does Cooperative Hydro Embrun find the response rates acceptable as a basis for measuring customer satisfaction? If so, why?
(c) How much weight did Cooperative Hydro Embrun give to the customer preferences identified in setting priorities for investment?
(d) What steps does Cooperative Hydro Embrun intend to undertake to improve the information regarding customer views of Cooperative Hydro Embrun’s performance. In your response, please address actions taken for commercial customers as well as other customers.

1-Staff-10
Ref 1: Exhibit 1/Section 1.7.2/Pages 52-54 – Customer Satisfaction Survey
Ref 2: Exhibit 1/Section 1.7.1/Page 49 – Overview of Customer Engagement

At reference 1, Cooperative Hydro Embrun discusses the results of a customer satisfaction survey. OEB staff notes that while a customer satisfaction survey is a good tool to gauge how a customer views the past performance of its utility, it is not necessarily a tool that engages customers on future plans.

(a) Did the survey contain data comparisons to an Ontario-wide LDC benchmark?
(b) Did the survey results help shape certain parts of Cooperative Hydro Embrun's current application? If yes, please explain what was adopted in this application as a direct result of the survey completed by customers.
(c) Did Cooperative Hydro Embrun conduct any benchmarking to support the current cost of service application?

At reference 2, Cooperative Hydro Embrun notes that it hosted a town hall meeting to discuss the 2017 and 2018 capital budget. Fifty customers attended the meeting and none of the attendees provided feedback on the proposed capital spending.

(d) Does Cooperative Hydro Embrun find the attendance rates acceptable as a basis for measuring customer wants? If so, why?
(e) Did Cooperative Hydro Embrun discuss its proposed OM&A budget and any specific programs related to OM&A? If yes, please provide a description. If not, please explain why.
(f) Please provide a copy of the presentation made to customers at the town hall meeting.

1-Staff-11
Ref: Exhibit 1/Section 1.5/Page 31 – Application Summary

Cooperative Hydro Embrun indicates that OM&A cost expenditures for the 2018 test year are the result of a planning and work prioritization process that ensures that the most appropriate cost effective solutions are put in place.

Please explain what type of criteria or strategy is used to determine which solutions are the most cost effective for Cooperative Hydro Embrun and its customers.

Exhibit 2 – Rate Base

2-Staff-12
Ref: Exhibit 2/Section 2.1.2/Page 8 – Rate Base Trend

Cooperative Hydro Embrun's rate base for the 2018 test year is forecast to increase significantly by approximately 62% from the 2014 OEB-approved amount.

(a) In its annual capital planning and implementation for the years 2014 to 2018, how did Cooperative Hydro Embrun take into account the cumulative impact its capital expenditures would have on rate base and rates in 2018 given the large increase?

(b) How did this inform the pacing of investments identified in the Distribution System Plan for 2018 forward?

2-Staff-13
Ref: Chapter 2 Appendices, Tab 2-AA – Capital Projects

(a) Please update tab 2-AA to include 2017 actuals to date.
(b) Please explain any significant variances from the 2017 budget to actuals.

2-Staff-14
Ref: Exhibit 2/Section 2.2.1/Pages 19-26 – Gross Assets

In Tables 9-12, Cooperative Hydro Embrun has provided a list of 2018 capital projects. The total Test Year 2018 gross capital expenditures for all projects is $150,205 (excluding contributed capital).

(a) Are all of the listed projects and related capital expenditures totaling $150,205 expected to be placed in-service in 2018 and to be added to the 2018 Rate Base?
(b) If some of the projects that are listed are not expected to be in-service in 2018 and as a result will not be added to the 2018 Rate Base, please identify all such projects, the associated capital expenditure and the expected in-service date.

2-Staff-15
Ref: Exhibit 2/Section 2.2.2/Page 28 – Accumulated Depreciation

The reference above is reproduced below:

CHEI has adopted depreciation rates based on the Kinectrics Asset Depreciation Study which can be found at this link [add link]. The rates used are presented below, and the Continuity Schedules of the Accumulated Depreciation are presented in the table below. CHEI's depreciation expense policy and methodology are provided on the next page. The depreciation expenses continuity schedules are presented at [references].

Please provide the missing link and references mentioned in the paragraph above.

2-Staff-16
Ref: Exhibit 2/Section 2.3.3/Page 31 – Calculation of Cost of Power

Please update the Cost of Power forecast to reflect the most recent RPP prices from the OEB's Report issued on June 22, 2017 (effective July 1, 2017) for the period from January 1, 2018 to April 1, 2018.

2-Staff-17
Distribution System Plan
Ref: Table ES-1: Historical Capital Investments by Year
Ref: Table ES-2: Forecast Capital Investments by Year

The forecasted system access budget is significantly less than the historical actuals but Cooperative Hydro Embrun has stated it anticipates load to grow by over 30% between 2017 and 2023. Please provide an explanation on how Cooperative Hydro Embrun can meet increased load growth with a lower budget.

2-Staff-18
Distribution System Plan
Ref: Overview of Assets Managed

Cooperative Hydro Embrun has stated that their system consists of about 15km of overhead lines and 12km of underground lines. Cooperative Hydro Embrun also plans to test wood poles to identify poles that are at end-of-life and in need of replacement. There has also been concern of a backup supply in the event of a failure at one of Cooperative Hydro Embrun's distribution stations.

(a) Can Cooperative Hydro Embrun provide a high level age demographic for the overhead and underground conductors? If it has not been historically tracked, does the utility intend to track this in an asset registry moving forward? If not, how does Cooperative Hydro Embrun budget replacement of these conductors when required?
(b) Does Cooperative Hydro Embrun intend to test all the poles in their distribution system to build an asset condition assessment of their pole population? If Cooperative Hydro Embrun only intends to test poles that are likely to fail, how does it currently identify this subset of poles?
(c) Has Cooperative Hydro Embrun done any condition assessments on their stations? Are there any inspection reports for each station that could be provided?

2-Staff-19
Distribution System Plan
Ref: Capital Actual Expenditure 2013

Cooperative Hydro Embrun spent $29,050 on pole replacement and $12,000 on transformer replacement in 2013. Please provide how many poles were installed and how many transformers were replaced.

2-Staff-20
Distribution System Plan
Ref: Capital Actual Expenditure 2013
Ref: EB-2013-0122 Capital Budget 2013

Cooperative Hydro Embrun states that in its last cost of service application (EB-2013-0122) that there was a need to construct a 4th feeder in 2013 to address future load growth and had forecasted 800 customers will be connected to this feeder.

(a) Please provide the number of customers that have been connected to this feeder and the loading on this feeder.
(b) Please provide the length of the portion of feeder constructed in 2013.
(c) Please provide a business case or any planning documents for this four year project.

2-Staff-21
Distribution System Plan
Ref: Capital Actual Expenditure 2014
Ref: EB-2013-0122 Capital Budget 2014

Cooperative Hydro Embrun had identified the system access project Faubourg Ste-Marie Subdivision in 2014. The two project accounts 1845 and 1850 had an estimated cost of $398,000 and $87,500, respectively, in the EB-2013-0122 Capital Budget. The actual expenditures reported in the Distribution System Plan for account 1845 and 1850 are $692,811 and $288,934 respectively.

(a) Please explain the variance of between the capital budget cost estimate in EB-2013-0122 and the reported actuals in this Distribution System Plan.
(b) Was there a capital contribution from the developer of the subdivision for this project? If so, how much?
(c) Please provide the business case for this project or any planning documents related to this project.

2-Staff-22
Distribution System Plan
Ref: Capital Expenditure Forecast to Year End 2017
Ref: Appendix C New Station Justification

Cooperative Hydro Embrun has planned a new substation transformer in the existing station for growing load demand and to provide redundancy to the system due to the loss of emergency backup supply from Hydro One. Cooperative Hydro Embrun also states that a transformer is working "harder" at ONAF and is not considered good engineering practice to continuously operate in this range.

(a) Please confirm how many subdivision units actually materialized in 2016 and 2017 compared to the estimates in Appendix C for South-East of Ste. Marie and Castor, South-West of Ste. Marie and Notre-Dame, and North-East of Notre-Dame and Rue Manoir.
(b) Does Cooperative Hydro Embrun have evidence that operating a transformer in its ONAF rating is bad engineering practice? Is the transformer not rated to operate continuously at the ONAF rating?
(c) What was the incremental cost of purchasing a 10MVA transformer compared to a 7MVA transformer?
(d) Does the existing transformer or the new transformer have overload capabilities? Please provide the transformer specifications and their summer and winter ratings.
(e) Please provide the cost breakdown of this project.

2-Staff-23
Distribution System Plan
Ref: Capital Forecast Expenditure 2020-2021

Cooperative Hydro Embrun has identified that there is a need over two years to replace transformer cutouts and arrestors due to safety concerns. In 2020, Cooperative Hydro Embrun has budgeted $40,000 for these projects. Please provide how many cutouts and arrestors were replaced for each year over the two year period.

2-Staff-24
Distribution System Plan
Ref: Capital Forecast Expenditure 2018-2022 – General Plant

Cooperative Hydro Embrun has budgeted $5,700 for the general plant category for software, office equipment, and computer & hardware. Although this amount does not meet the materiality threshold it is a repeated yearly cost. Please provide some information on how Cooperative Hydro Embrun plans to spend this money and why there is a yearly upkeep.

Exhibit 3 – Operating Revenue

3-Staff-25
Ref: Load Forecasting Model, Tab "Bridge&Test Year Class Forecast"

It appears as though there is a formula error in cell B42. OEB staff notes that the cell currently sums I129-I140 from the "Input –Customer Data" tab. OEB staff believes the cell should sum I140-I151. Please make the necessary corrections to the re-filed Load Forecasting Model.

3-Staff-26
Ref: Load Forecasting Model, Tab "Bridge&Test Year Class Forecast"

OEB staff observes that the demand data (kW) shows a decrease of approximately 45% from 2016 to 2015 (from 1050 to 576 kW) for the Street Lighting rate class. However, the kWh consumption levels have not decreased by a proportionate percentage.

(a) Please provide an explanation.
(b) Please recalculate the kWh for 2016 using an average kW/kWh ratio from 2007 to 2015.

3-Staff-27
Ref: Exhibit 3/Section 3.1.7/Page 16/Table 4 – HDD and CDD as Reported at Utility Location

OEB staff notes that the "Total" columns for the "HDD and CDD as reported at Utility Location" do not sum correctly. Please reconcile and provide the corrected tables.

3-Staff-28
Ref 1: Exhibit 3/Section 3.1.7/Page 16/Table 4 – HDD and CDD as Reported at Utility Location
Ref 2: Load Forecasting Model – Tab "Input – Adjustments and Variables"

OEB staff notes that at reference 2 above, the CDD were entered beginning in June 2007 whereas the table in reference 1 shows the data beginning in May 2007 (i.e. the numbers have been shifted downwards by one month). Please correct the Cost

Allocation Model for this error and provide an updated version in accordance with interrogatory 6-Staff-47.

3-Staff-29
Ref 1: Exhibit 3/Section 3.4/Pages 54-61/Table 32 – Other Revenue
Ref 2: Chapter 2 Appendices – Tab 2-H

Tab 2-H of the Chapter 2 appendices is reproduced below:

	Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
		2014	2014	2015	2016	2017	2018
	USoA Description	Board Approved					
4235	4235-Miscellaneous Service Revenues	-$14,200	-$14,580	-$16,185	-$18,595	-$19,721	-$20,041
4225	4225-Late Payment Charges	-$6,000	-$7,963	-$9,946	-$11,283	-$11,320	-$11,400
4082	4082-Retail Services Revenues	-$4,130	-$3,343	-$3,398	-$3,151	-$3,239	-$3,245
4084	4084-Service Transaction Requests (STR) Revenues	$13	-$2	-$2	-$8	-$9	-$10
4210	4210-Rent from Electric Property	$0	-$6,561	-$5,917	-$6,452	-$6,482	-$6,593
4240	4240-Provision for Rate Refunds	$0	$21,935	$20,000	$20,000	$20,000	$20,000
4375	4375-Revenues from Non-Utility Operations	$0	-$31,129	-$9,347	-$3,215	-$75,000	-$30,000
4380	4380-Expenses of Non-Utility Operations	$0	$21,859	$0	$3,215	$75,000	$30,000
4390	4390-Miscellaneous Non-Operating Income	$0	$0	-$7,443	-$12,331	-$5,000	-$5,500
4405	4405-Interest and Dividend Income	$0	-$28,723	-$23,486	-$22,161	-$11,000	-$2,000
	Total	-$30,317	-$48,507	-$55,725	-$53,980	-$36,770	-$28,789

	Specific Service Charges	-$14,200	-$14,580	-$16,185	-$18,595	-$19,721	-$20,041
	Late Payment Charges	-$6,000	-$7,963	-$9,946	-$11,283	-$11,320	-$11,400
	Other Distribution/Operating Revenues	-$4,117	$12,029	$10,683	$10,389	$10,271	$10,152
	Other Income or Deductions	$0	-$37,993	-$40,276	-$34,491	-$16,000	-$7,500
	Total	-$24,317	-$48,507	-$55,725	-$53,980	-$36,770	-$28,789

(a) Please provide an explanation for the swings in the amounts in Accounts 4375 and 4380 from 2014 to 2018.
(b) Please explain why for 2014 and 2015 the amounts in the accounts noted in part (a) are not offsetting as seen in 2016-2018.
(c) Please explain why the "total" rows for 2014 Board Approved do not match (i.e. -$30,317 at the top portion of the table and -$24,317 at the bottom portion).

3-Staff-30
Ref: Exhibit 3/Section 3.4.3/Page 61 – Proposed Specific Service Charges

Cooperative Hydro Embrun is proposing a change to the microFIT service charge. Cooperative Hydro Embrun incurs a $10.00 monthly fee per microFIT meter point from its vendor Utilismart and would like to pass this charge onto its microFIT customers.

(a) Please confirm if Cooperative Hydro Embrun has provided for this increase in revenue in its 2017 revenue offsets. If not, please make the applicable corrections.

(b) How many customers would be impacted by this change?
(c) How much revenue would the change in the microFIT rate equate to on an annual basis?

Exhibit 4 – Operating Expenses

4-Staff-31
Ref 1: Exhibit 4
Ref 2: Chapter 2 Appendices

Please update the following tabs in the Chapter 2 appendices for actuals to date:

1. Tab 2-JA – OM&A Summary Analysis (Page 8 of Exhibit 4)
2. Tab 2-JB – OM&A Cost Drivers (Page 9 of Exhibit 4)
3. Tab 2-JC – OM&A Programs (Page 22 of Exhibit 4)
4. Tab 2-K – Employee Costs (Page 34 of Exhibit 4)
5. Tab 2-L – OM&A Cost per FTE (Page 17 of Exhibit 4)

4-Staff-32
Ref: Chapter 2 Appendices, Tab 2-JA

The proposed OM&A costs in 2018 of $721,971 represent an increase of $152,890 or 27% over the 2014 actual OM&A.

(a) Please identify any customer engagement relating specifically to the increase in OM&A that supports the increases proposed in this application.
(b) Please identify what if any improvements in services and outcomes the applicant's customers will experience in 2018 and during the subsequent IRM term as a result of increasing the provision for OM&A at the rate indicated.
(c) Please identify any initiatives considered and/or undertaken by Cooperative Hydro Embrun, including any analysis conducted, to optimize plans and activities from a cost perspective.

4-Staff-33
Ref: Exhibit 4/Section 4.1.1/Page 6 - Overview

	2014 Board Approved	2018	Diff
Operations	$20,900	$37,769	$16,869
Maintenance	$40,300	$56,215	$15,915
Billing and Collecting	$170,174	$209,970	$39,796
Community Relations	$4,000	$7,875	$3,875
Administrative and General	$320,905	$410,142	$89,237
Total	**$556,279**	**$721,971**	**$165,692**
%Change (year over year)			29.79%

Cooperative Hydro Embrun notes that the majority of the variance in OM&A between the 2014 OEB-approved and 2018 test year is attributable to an increase in administrative costs. Please provide a breakdown of what the $89k increase consists of (i.e. what are the discrete items).

4-Staff-34
Ref: Exhibit 4/Section 4.2.1/Page 10 – Summary of Cost Drivers

Cooperative Hydro Embrun included a one-time severance pay ($45k) after terminating an employee and an increase in salaries ($7k) for 2 customer service representatives in Account 5315 – Customer Billing.

Please explain the rationale for including these costs in this account.

4-Staff-35
Ref: Exhibit 4/Section 4.4/Page 35 – Workforce Planning and Compensation Strategy

Cooperative Hydro Embrun notes that it does not use specific benchmarking studies to determine salary ranges, however uses neighbouring utilities' salaries a guideline. In addition, when compared to the Sunshine List, its salaries and increases over the last 4 years are well below those published in the Sunshine List.

(a) Does Cooperative Hydro Embrun plan on undertaking in the future any benchmarking analysis to comparable utilities?
(b) Please explain why Cooperative Hydro Embrun believes the Sunshine List is an appropriate comparable benchmark for its salary ranges.

4-Staff-36
Ref 1: Exhibit 4/Section 4.4/Page 35 – Workforce Planning and Compensation Strategy
Ref 2: Chapter 2 Appendices – Tab 2-K

Reference 2 is reproduced below:

	Last Rebasing Year - 2014-Actual	2015 Actuals	2016 Actuals	2017 Bridge Year	2018 Test Year
Number of Employees (FTEs including Part-Time)[1]					
Management (including executive)	1	1	1	1	1
Non-Management (union and non-union)	2	2	2	2	2
Total	3	3	3	3	3
Total Salary and Wages including ovetime and incentive pay					
Management (including executive)	$ 188,050	$ 213,055	$ 233,874	$ 215,007	$ 225,000
Non-Management (union and non-union)	$ -				
Total	$ 188,050	$ 213,055	$ 233,874	$ 215,007	$ 225,000
Total Benefits (Current + Accrued) [2]					
Management (including executive)	$ 30,053	$ 30,753	$ 26,894	$ 30,136	$ 31,650
Non-Management (union and non-union)	$ -				
Total	$ 30,053	$ 30,753	$ 26,894	$ 30,136	$ 31,650
Total Compensation (Salary, Wages, & Benefits)					
Management (including executive)	$ 218,104	$ 243,808	$ 260,768	$ 245,143	$ 256,650
Non-Management (union and non-union)	$ -	$ -	$ -	$ -	$ -
Total	$ 218,104	$ 243,808	$ 260,768	$ 245,143	$ 256,650

At reference 1, Cooperative Hydro Embrun notes that periodically the Board of Directors along with management input re-adjusts employee salary to be in line with neighbouring cohorts, however as a rule, the utility tries to apply a 2% inflation factor to salaries and wages.

(a) Please explain the varying amounts for total salary and wages including overtime and incentive pay in 2015 to 2017 (i.e. $213k in 2015 up to $233k in 2016 and back down to $215k in 2017).

(b) Please confirm if Cooperative Hydro Embrun agrees with the year over year increases/decreases below calculated by OEB staff:

	2014 Approved	2014 Actual	2015	2016	2017	2018
Total OM&A	$556,279	$569,081	$613,072	$601,025	$651,616	$721,971
% increase per year	-	2.3%	8%	-2%	8%	11%

(c) Please explain the increases given that Cooperative Hydro Embrun tries to apply a 2% inflation factor to salaries and wages. Are these increases the result of overtime, vacation paid out etc.?

4-Staff-37
Ref: Exhibit 4/Section 4.6.3/Page 45 – Regulatory Costs

	Worst Case
AESI (DSP)	$25,000.00
BDO (PILs + DVAs + IRs)	$10,000.00
Production & Submission (Print)	$1,000.00
Public Notice (OEB)	$1,000.00
Legal - Review, IR, Settlement, DRO	$32,000.00
Legal - Oral hearing	$45,000.00
Intervenor costs	$40,000.00
Community Meeting	$10,000.00
Total Cost of Service Filing costs	$164,000.00

Cooperative Hydro Embrun indicates that the regulatory costs proposed in the application include provision for legal fees related to an Oral Hearing if the parties are unable to reach a full settlement and includes provision for up to 2 intervenors. Cooperative Hydro Embrun proposes to remove these costs if the application is dealt with via written hearing or parties reach a full settlement and if only one intervenor gets involved in the application.

Please provide a breakdown by category of the costs proposed to be removed given that this proceeding has one approved intervenor. Please also provide two tables with the proposed costs to be removed if there is 1) a full settlement, and 2) a partial settlement.

4-Staff-38
Ref: Exhibit 4/Section 4.10/Page 60 – Non-Recoverable and Disallowed Expenses

OEB staff is unable to find a reference to property taxes applicable to Cooperative Hydro Embrun.

(a) Please confirm if Cooperative Hydro Embrun pays property taxes.
(b) If Cooperative Hydro Embrun does pay property taxes, please provide the most recent OEB-Approved, historical years 2014-2016, the 2017 bridge year and the 2018 test year amounts.

4-Staff-39
Ref: Exhibit 4/Section 4.12.2/Pages 64-66 - LRAMVA

OEB staff notes that if the OEB approves a distributor’s account balances on a final basis, any adjustments made to prior years by the IESO are not recoverable.

Is Cooperative Hydro Embrun expecting any retroactive adjustments from the IESO to its savings?

4-Staff-40
Ref: Tab 1 of 2018 LRAMVA Work Form (May 1, 2017)

Cooperative Hydro Embrun applied for a debit balance of $10,951 in lost revenues associated with new CDM programs savings between 2013 and 2015, and persisting savings from 2013 to 2015. Of this original amount, it includes a credit balance of $3,855 to indicate the 2011 and 2012 LRAMVA amounts cleared in the 2014 COS application (EB-2013-0122).

As noted in Cooperative Hydro Embrun's 2018 COS application, the LRAMVA request pertains to disposing of balances related to 2013, 2014 and 2015.

(a) Please provide rationale for including a credit balance of $3,855 for 2011 and 2012 amounts, as the current disposition is related to seeking recovery for 2013-2015 amounts.
(b) As past approved amounts do not need to be included in the balance of the current LRAMVA disposition, please confirm appropriateness of removing the credit amount of $3,855 from Table 1 (cell K27).

4-Staff-41
Ref: Tab 2 of 2018 LRAMVA Work Form (May 1, 2017)

In the LRAMVA work form, Cooperative Hydro Embrun included the following amounts for forecast CDM savings used for comparison against actual program results: 38,800 kWh in 2013, and 38,800 kWh in 2014, and 0 kWh in 2015.

(a) Please confirm the LRAMVA threshold approved in the 2010 COS application. Please also provide the rate class specific breakdown of the 2010 LRAMVA threshold, as it appears the 2010 LRAMVA threshold amount was not reflected in Tab 2.
(b) Please update in Table 2 of your application using the approved LRAMVA threshold from the 2010 cost of service application in the calculation of 2013 LRAMVA amounts.

4-Staff-42
Ref: Tab 2 of 2018 LRAMVA Work Form (May 1, 2017); 2014 DRO Load Forecast Worksheet (revision Jan 10, 2014)

In Cooperative Hydro Embrun's 2014 Draft Rate Order in the 2014 cost of service application, the approved LRAMVA threshold was 388,471 kWh in 2014.
As indicated in the filing requirements and CDM Guidelines, the LRAMVA threshold approved as part of a distributor's most recent cost of service application is to be used as part of the LRAMVA calculation.

(a) Please discuss why Cooperative Hydro Embrun has not used the LRAMVA threshold of 388,471 kWh approved in its 2014 CoS to calculate the following LRAMVA amounts:
    i. 2014
    ii. 2015
(b) Please discuss why Cooperative Hydro Embrun has used the following LRAMVA thresholds:
    i. 2014 – 38,800 kWh
    ii. 2015 – 0 kWh
(c) Please update your application using the approved LRAMVA threshold of 388,471 kWh in the calculation of 2014 and 2015 LRAMVA amounts.

4-Staff-43
Ref: Tab 3 of 2018 LRAMVA Work Form (May 1, 2017)

In Table 5, it appears that the number of months in period 1 (row 18) have not been entered correctly. In order to convert rates to a January to December year equivalent, the number of months should capture the amount of time from January to the start of the LDC's rate year. Please note that if rates were implemented in May, four months should be entered in row 18 to reflect the rate effective for the first four months of the year.

Please adjust the entries in row 18 of Table 5.

4-Staff-44
Ref: Tab 7 of 2018 LRAMVA Work Form (May 1, 2017); Exhibit 4 of Application page 65 of 69

As part of the LRAMVA disposition, Cooperative Hydro Embrun indicated that it would collect carrying charges up to April 30, 2015. In Tab 7 of the work form, it appears that carrying charges are collected up to the period of December 30, 2015.

(a) Please confirm the time period Cooperative Hydro Embrun is collecting carrying charges until.

(b) Please confirm the amount of the carrying charges to be included in the disposition.

(c) Please re-submit a revised version of the work form to address changes to the work form in response to questions 4-Staff-40 to 4-Staff-43 above.

Exhibit 5 – Cost of Capital and Capital Structure

5-Staff-45
Ref 1: Exhibit 5/Section 5.5.4/Page 11 – Long-Term Debt
Ref 2: Exhibit 5/Appendix B/Page 1 – Promissory Note

Section 1.2 of the Promissory Note attached as Appendix B indicates a 5-year term for the $1,000,000 Promissory Note. Section 1.3 indicates an amortization period of 20 years.

Please confirm if the 2.9% interest rate is for the 20 year term or is it renegotiable after 5 years.

Exhibit 6 – Calculation of Revenue Deficiency

6-Staff-46
Ref: Exhibit 6/Section 6.2.1/Page 4/Table 1 – Distribution Revenues as Current Rates – 2018 Volumes

2017 Rates at 2018 Load	Test Year Projected Revenue from Existing Fixed Charges							
Customer Class Name	Fixed Rate	Customers (Connections)	Fixed Charge Revenue	Variable Revenue	TOTAL	% Fixed Revenue	% Variable Revenue	% Total Revenue
Residential	$21.8700	2,100	$21.8700	2,100	$551,124.00	$155,637.67	$706,761.67	77.98%
General Service < 50 kW	$17.9000	172	$17.9000	172	$36,969.84	$74,644.73	$111,614.58	33.12%
General Service > 50 to 4999 kW	$199.4500	9	$199.4500	9	$21,540.60	$47,068.45	$68,609.05	31.40%
Unmetered Scattered Load	$21.1600	17	$21.1600	17	$4,415.87	$451.70	$4,867.57	90.72%
Street Lighting	$1.9900	530	$1.9900	530	$12,646.72	$4,878.84	$17,525.56	72.16%
Total Fixed Revenue		2,828		2,828	$626,697.03	$282,681.40	$909,378.43	

A portion of Table 1 is replicated above. OEB staff notes that the “Fixed Charge Revenue” column duplicates the fixed rates in column 1, which is incorrect. Please provide an updated table with the fixed charge revenues calculated.

6-Staff-47

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

Also upon completing all interrogatories from OEB staff and intervenors please provide any updates to the following Microsoft Excel documents in working format: PILS, any Appendix 2 changes (e.g. cost allocation, rate design, and so on as required), EDDVAR spreadsheet, Tariff and Bill Impact Model and the updated cost allocation model reflecting the revised revenue requirement in the updated RRWF.

In its application, Cooperative Hydro Embrun notes that at the time of filing, the OEB had not yet updated its Bill Impact Work Form and therefore used its own bill impacts which replicate an older format of the OEB's calculation. Along with these interrogatories, OEB staff has attached an updated Tariff and Bill Impact Model to be used by Cooperative Hydro Embrun in its interrogatory responses.

Exhibit 7 – Cost Allocation

7-Staff-48
Ref 1: Exhibit 7/Section 7.2.1/Page 11/Table 6 – Sheet I6-1 of the Cost Allocation Model
Ref 2: Cost Allocation Model – Tab I6.1: Revenue

OEB staff notes that the data entered in Table 6 of the application does not match Tab I6.1 of the Cost Allocation Model. OEB staff notes that the data entered in the Cost Allocation Model matches to the proposed load forecast and RRWF. Please confirm that the data entered in the table on page 11 of exhibit 7 are typographical errors.

7-Staff-49
Ref 1: Exhibit 7/Section 7.4.1/Page 19/Table 15 – 2018 Allocation
Ref 2: Exhibit 7/Section 7.4.1/Page 20
Ref 3: Revenue Requirement Work Form, Tab 11 – Cost Allocation

Reference 1 is reproduced below:

Table 15 – 2018 Allocation

Customer Class Name	Calculated R/C Ratio	Proposed R/C Ratio	Variance	Target Range Floor	Target Range Ceiling
Residential	1.02	0.99	0.03	0.85	1.15
General Service < 50 kW	0.54	0.90	-0.36	0.80	1.20
General Service > 50 to 4999 kW	1.88	1.50	0.38	0.80	1.20
Unmetered Scattered Load	1.31	1.20	0.11	0.80	1.20
Street Lighting	0.79	0.80	-0.01	0.80	1.15

At Reference 2, Cooperative Hydro Embrun notes “At its current rates, the General Service >50kW is slightly over-recovering revenues in comparison to its allocated costs. Since the calculated ratio of 1.88 is higher than the ceiling of 1.50, adjusting it down to the ceiling is being proposed.”

A portion of reference 3 is reproduced below:

Name of Customer Class	Proposed Revenue-to-Cost Ratio Test Year 2017	Price Cap IR Period 2018	Price Cap IR Period 2019	Policy Range
Residential	99.24%	99.24%	99.24%	85 - 115
General Service < 50 kW	89.93%	89.93%	89.93%	85 - 115
General Service > 50 to 4999 kW	150.06%	150.06%	150.06%	80 - 120
Unmetered Scattered Load	120.05%	120.05%	120.05%	80 - 120
Street Lighting	79.74%	79.74%	79.74%	80 - 120

(a) Please correct the RRWF at Tab 11 (reference 3) which currently notes 2017 as the test year as opposed to 2018.

(b) At reference 2, Cooperative Hydro Embrun indicates the ceiling for the GS 50 to 4,999kW rate class to be 150%. As seen in reference 3, the OEB’s policy range for this rate class is 120%. Please reconcile.

(c) Please explain why Cooperative Hydro Embrun has not proposed to bring this ratio down to 120%. If any changes are required to the models, please make the updates in accordance with 6-Staff-47.

(d) Please explain how the proposed revenue to cost ratios impact the bill impacts as found in exhibit 8. For example, OEB staff notes that the revenue to cost ratio for the GS<50kW class is increasing by approximately 30%, yet the bill impact shows an overall decrease. Similarly, the revenue to cost ratio for the Residential class is decreasing, however the bill impacts show a large increase.

7-Staff-50
Asset Functionalization and Demand Allocators
Ref: Cost Allocation Model, Sheet I4 BO Assets
Ref: Cost Allocation Model, Sheet I6.2 Customer Data, Sheet I8 Demand Data

Cooperative Hydro Embrun has not separately identified primary and secondary assets for accounts 1830 – Poles towers and Fixtures, 1835 – Overhead Conductors and Devices, and 1845 – Underground Conductors and Devices. The prepared model functionalizes all assets as Secondary voltage. This can result in an unfair allocation of costs to street lighting as well as to rate classes where some customers do not receive secondary distribution, if any.

In addition, Cooperative Hydro Embrun has identified every customer in every rate class, as well as every kW of demand in every rate class as being served at secondary voltage.

(a) Please review the assets, and perform a breakout to Primary and Secondary using the best information available.
(b) Please confirm that every customer of Cooperative Hydro Embrun is connected to secondary distribution service.

7-Staff-51
Asset Functionalization
Ref: Cost Allocation Model, Sheet I4 BO Assets

Account 1855 – Services has a negative asset value, net of Accumulated Depreciation and Contributed Capital.

Please review the gross asset, accumulated amortization, contributed capital, and amortization of contributed capital for all asset categories, and update as required.

7-Staff-52
Weighting Factors
Ref: Cost Allocation Model, Sheet I5.2 BO Assets

Cooperative Hydro Embrun has used the same weighting factor for Billing and Collecting for all rate classes.

Please provide a derivation of the Billing and Collecting weighting factors.

7-Staff-53
Customer Data
Ref: Cost Allocation Model, Sheet I6.2 Customer Data

The Street Light rate class does not have the Number of Devices field populated at cell J18. As a result, the Street Lighting Adjustment Factors calculation at the bottom of this sheet is unable to calculate an adjustment factor, and it is not possible for the model to accurately allocate costs to the Street Light rate class.

Please review the device count and connection count, and update as necessary.

7-Staff-54
Meter Count
Ref: Cost Allocation Model, Sheet I6.2 Customer Data, Sheet I7.1 Meter Capital

Cooperative Hydro Embrun has identified 172 GS < 50 customers on sheet I6.2 Customer Data, but has only entered a total of 163 meters on sheet I7.1 Meter Capital. Please reconcile.

7-Staff-55
Meter Reading
Ref: Cost Allocation Model, Sheet I6.2 Customer Data, Sheet I7.2 Meter Reading

Cooperative Hydro Embrun has identified 172 GS < 50 customers and 9 GS > 50 customers on sheet I6.2 Customer Data, but has not entered any meter reading for GS < 50, and only entered 8 interval meter reading for GS > 50. Please reconcile.

7-Staff-56
Demand Allocators
Ref: Cost Allocation Model, Sheet I6.1 Revenue, Sheet I8 Demand Data

Cooperative Hydro Embrun has used a forecast of 603 kW of streetlight billing demand on sheet I6.1 Revenue, and a on Sheet I8 Demand Data, a 12 NCP Demand of 1,092 kW for the same rate class. The billing demand value on sheet I6.1 Revenue should match or exceed the 12 NCP value on sheet I8 Demand Data. This may be related to IR 3-Staff-25.

Please review the calculation of the values on sheet I8 Demand Data, and correct as necessary.

7-Staff-57
Load Profile Update
Ref: Update of Demand Data worksheet

Cooperative Hydro Embrun has used load profiles, prepared by Hydro One based on 2004 data as the starting point for its 2018 load profiles and demand allocators.

Please confirm that Cooperative Hydro Embrun will endeavour produce updated load profiles based on smart meter and interval meter data in its next rebasing application.

7-Staff-58
Load Profile Update
Ref: Update of Demand Data worksheet

In calculating the 1NCP values for each rate class, Cooperative Hydro Embrun has selected the peak for January, rather than selecting the class peak for each rate class.

Please revise the 1NCP calculation to reflect the class peak for each rate class.

Exhibit 8 – Rate Design

8-Staff-59
Ref 1: Exhibit 8/Section 8.1.4/Page 12 – Retail Transmission Service Rates
Ref 2: RTSR Workform, Tab 5 – UTRs and Sub-Transmission

Please update the RTSR Workform for the most recent Hydro One Sub-Transmission rates issued by the OEB in its Decision on December 21, 2016 effective January 1, 2017 (EB-2016-0081).

The rates are:

- Retail Transmission Rate – Network Service Rate: $3.1942/kW
- Retail Transmission Rate – Line Connection Service Rate: $0.7710/kW
- Retail Transmission Rate – Transformation Connection: $1.7493/kW

8-Staff-60
Ref: Exhibit 8/Section 8.1.10/Page 24/Table 15 – Calculation of Proposed Low Voltage Charges

Please explain the significant difference in the uplifted versus non uplifted volumes for the Street Lighting rate class, and make any corrections, as required.

Low Voltage Charges - Allocation of LV Charges based on Transmission Connection Revenues

Customer Class Name		RTSR Rate	Uplifted Volumes	Revenue	% Alloc
Residential	kWh	$0.0059	22,548,045	$132,492	70.83%
General Service < 50 kW	kWh	$0.0051	5,260,949	$26,830	14.34%
General Service > 50 to 4999 kW	kW	$2.0670	12,736	$26,326	14.07%
Unmetered Scattered Load	kWh	$0.0051	85,667	$437	0.23%
Street Lighting	kW	$1.5979	603	$964	0.52%
TOTAL			**27,908,005**	**$187,049**	**100.00%**

Customer Class Name	% Allocation	Charges	Not Uplifted Volumes	Rate	per
Residential	70.83%	69,699	21,616,344	$0.0032	kWh
General Service < 50 kW	14.34%	14,115	5,043,563	$0.0028	kWh
General Service > 50 to 4999 kW	14.07%	13,849	2,827,501	$0.0049	kW
Unmetered Scattered Load	0.23%	230	82,127	$0.0028	kWh
Street Lighting	0.52%	507	393,969	$0.0013	kW
TOTAL	**100.00%**	**98,400**	**29,963,508**		

8-Staff-61
Ref: Exhibit 8/Section 8.1.11/Page 25 – Loss Adjustment Factors

Cooperative Hydro Embrun notes that although it was not directed to conduct a line loss study as part of its previous cost of service application, the utility makes a point of doing so prior to each rebasing application.

Has Cooperative Hydro Embrun included the cost of the new study in this application? If so, please indicate where the costs have been included.

8-Staff-62
Ref 1: Exhibit 8/Section 8.1.11/Page 26 – Loss Adjustment Factors
Ref 2: Chapter 2 Appendices, Tab 2-R

With respect to row A(1), the instructions on Tab 2-K note: If fully embedded within a host distributor, kWh pertains to the virtual meter on the primary or high voltage side of the transformer, at the interface between the host distributor and the transmission grid. For example, if the host distributor is Hydro One Networks Inc., kWh from the Hydro One Networks' invoice corresponding to "Total kWh w Losses" should be reported. This corresponds to the higher of the two kWh values provided in Hydro One Networks' invoice.

Please explain why row A(1) has not been populated.

8-Staff-63

Ref 1: Exhibit 8/Section 8.1.16/Page 32 – Rate Mitigation/Foregone Revenue
Ref 2: Exhibit 8/Section 8.1.2/Pages 5-6 – Rate Design Policy Consulation
Ref 3: EB-2012-0410 Board Policy: A New Distribution Rate Design for Residential Electricity Customers

Cooperative Hydro Embrun indicates that the total bill impacts for customers at the 10th percentile of consumption are over 10% (15.72%) and has analysed and tested all options available to the utility to minimize the rates for low volume consumers. For example, selecting a longer transition periods for the transition to fixed rate.

Currently, the disposition periods set out below have been proposed as part of the application.

Description	Disposition Period
Accounts 1550,1551,1584,1586,1595	1
Accounts 1580,1588	1
Account 1589 Global Adjustment	1
Group 2 Accounts	1
Account 1568 LRAMVA	1
Fixed Rate Design Transition	5 (2 years remaining)

(a) Please provide bill impact (total bill % and $) scenarios using illustrating 2 and 3 year disposition periods for the Group 1 and Group 2 DVAs, while keeping all else proposed in the application the same.

Exhibit 9 – Deferral and Variance Accounts

9-Staff-64
Ref: Deferral and Variance Account Work Form, July 14, 2017

On July, 24, 2017, the OEB posted an updated Deferral and Variance Account Work Form which corrected for some inconsistencies in the previous version.

To ensure that account balances are allocated appropriately to all rate classes, please populate and file the latest version of the Deferral and Variance Account Work Form.

9-Staff-65
Ref: EDDVAR Continuity Schedule and 2.1.7 Reporting for 2016, Account 1592

According to Cooperative Hydro Embrun's 2.1.7 reporting as of December 31, 2016, there is a balance of $13,097 in Account 1592, PILs and Tax Variances. However, there is no balance shown it Cooperative Hydro Embrun's Continuity Schedule.

(a) Please explain the discrepancy between the evidence filed and the 2.1.7 reporting.
(b) Why is Cooperative Hydro Embrun not proposing disposition of the balance in this account?
(c) Please update the evidence as necessary.

9-Staff-66
Ref: Chapter 2 of the Filing Requirements for Electricity Distribution Rate Applications – 2017 Edition for 2018 Rate Applications, Page 66

Effective May 23, 2017, per the OEB's letter titled Guidance on Disposition of Accounts 1588 and 1589, applicants must reflect RPP Settlement true-up claims pertaining to the period that is being requested for disposition in the RSVA Power (Account 1588) and RSVA GA (Account 1589) variance accounts. In doing so, distributors are to follow the guidance provided in the above noted letter.

Please update Cooperative Hydro Embrun's EDDVAR Model to reflect any RPP settlement true-up claims.

9-Staff-67
Ref: GA Analysis Workform
Ref: Chapter 2 of the Filing Requirements for Electricity Distribution Rate Applications – 2017 Edition for 2018 Rate Applications, Page 67

On July 24, 2017 the OEB issued its Deferral and Variance Account Workform for 2018 cost of service rate application. Given that Cooperative Hydro Embrun filed its application before this date, please update the Deferral and Variance Account Workform by completing sheet 7.a GA Analysis Workform.

9-Staff-68
Ref: GA Analysis Workform

1) In booking expense journal entries for Charge Type 1142 (formerly 142), and Charge Type 148 from the IESO invoice, please confirm which of the following approaches is used:

a) Charge Type 1142 is booked into Account 1588. Charge Type 148 is pro-rated based on RPP/non-RPP consumption and then booked into Account 1588 and 1589, respectively
b) Charge Type 148 is booked into Account 1589. The portion of Charge Type 1142 equalling RPP-HOEP for RPP consumption is booked into Account 1588. The portion of Charge Type 1142 equalling GA RPP is credited into Account 1589.
c) Another approach. Please explain this approach in detail.

2) With regards to the Dec. 31, 2016 balance in Account 1589:
   a) Please indicate whether the items that flow into the account (i.e. revenues, expenses, CT 142) are based on estimates/accruals or actuals at year end.
   b) If there are reconciling items #1a, 1b in the GA Analysis Workform or if there are any proposed adjustments to Account 1589 in the DVA Continuity Schedule for the true up impacts, please quantify the adjustments that relate to each of the following items:
      i. Revenues (i.e. is unbilled revenues trued up)
      ii. Expenses - GA non-RPP (Charge Type 148) with respect to the quantum dollar amount and RPP/non-RPP pro-ration percentages
      iii. Credit of GA RPP (Charge Type 142) if the approach under IR 1b is used

3) With regards to the Dec. 31, 2016 balance in Account 1588:
   a) Please indicate whether the items that flow into the account (i.e. revenues, expenses, CT 142) are based on estimates/accruals or actuals at year end.
   b) If there are any proposed adjustments to Account 1588 in the DVA Continuity Schedule for the impacts of RPP settlement true up, please quantify the adjustment that relate to each of the following items:
      i. Revenues (i.e. is unbilled revenues trued up)
      ii. Expenses - Commodity (Charge Type 101)
      iii. Expenses - GA RPP (Charge Type 148) with respect to the quantum dollar amount and RPP/non-RPP pro-ration percentages
      iv. RPP Settlement (Charge Type 1142 - including any data used for determining the RPP/HOEP/RPP GA components of the charge type)

9-Staff-69
Ref 1: EDDVAR Model, Tab 2 – Continuity Schedule
Ref 2: 2012 IRM Decision and Order (EB-2011-0164), Page 8

OEB staff notes that in column Q, the 2012 OEB-approved principal amounts have been transposed for Accounts 1588 - Power and 1589 – Global Adjustment.
Please make the necessary corrections to the continuity schedule.

9-Staff-70
Ref: EDDVAR Model, Tab 2 – Continuity Schedule

OEB staff notes that interest amounts on the balances requested for disposition up to December 31, 2017 have not been included.

Please make the necessary corrections to the continuity schedule.

9-Staff-71
Ref 1: Exhibit 1/Section 1.3.10/Page 17 – Board Directive from Previous Decisions
Ref 2: Exhibit 1/Page 43 – Overview of Deferral and Variance Account Disposition
Ref 3: Exhibit 9/Section 9.3.2//Page 11 – Disposition of DVAs Used by the Applicant

At reference 1, Cooperative Hydro Embrun notes that it is not aware of any OEB directives from any previous OEB decisions that require addressing.

OEB staff notes that in its 2016 IRM Decision (EB-2015-0063), the OEB ordered an audit of Account 1595 and noted that disposition of the account will be considered in the next rate application following the audit. Similarly, in Cooperative Hydro Embrun's 2017 IRM Decision (EB-2016-0065), the OEB noted that given that the results of the OEB's audit were not yet available, the clearance of Account 1595 was not appropriate at that time. Cooperative Hydro Embrun was expected to bring forward the request for disposition of Account 1595 in the first application following completion of the audit.

(a) If the audit has been completed, please provide a table summarizing the findings of the audit, the resulting adjustments, and an explanation of each adjustment.
(b) Please confirm that the table provided in (a) includes all of the adjustments required by the audit.
(c) If any changes are required to the application as a result of the OEB's audit, please make the necessary corrections to the DVA Continuity Schedule as part of the EDDVAR Model and update Cooperative Hydro Embrun's request for disposition of its DVAs.
(d) If changes are made in response to part (c) above, please confirm that these adjustments align with the findings of the OEB audit.

9-Staff-72
Ref 1: Exhibit 9/Section 9.8/Page 29 – Account 1576 Accounting Changes Under CGAAP
Ref 2: EDDVAR Model, Tab 6 – Rate Rider Calculations
Cooperative Hydro Embrun transitioned to MIFRS on January 1, 2015 and therefore the difference in depreciation due to the adoption of useful lives was addressed in its 2014 CoS application. Cooperative Hydro Embrun notes that it has not used Account 1576 in this application and is therefore requesting discontinuation of this account.

OEB staff notes that at Tab 6 of the EDDVAR Model, a balance of -$0.44 is being disposed to all rate classes and a rate rider is calculated for the GS 50 to 4,999kW rate class. Please confirm this is an error and remove the amounts for Account 1576.

9-Staff-73
Ref 1: Exhibit 9/Section 9.9.2/Pages 35-37 – Calculation of Rate Rider
Ref 2: EDDVAR Model, Tab 6 – Rate Rider Calculations

(a) OEB staff notes that the rate riders listed in the tables on the above noted pages of the application do not match those being produced from the EDDVAR Model. Please reconcile and/or update the evidence as necessary.
(b) OEB staff notes that Cooperative Hydro Embrun has calculated its Group 2 rate riders for all rate classes on a fixed basis. The OEB policy requires fixed rate riders for Group 2 for residential class only. Please recalculate update the rate riders for Group 2.
(c) OEB staff notes that the last column in the Rate Rider Calculation for Group 2 Accounts is labelled “Rate Rider for RSVA – Power – Global Adjustment”. Please confirm that this Table is related to Group 2.