CREATIVENERGY

2 April 2020

Via E-filing

Mr. Patrick Wruck
Commission Secretary
BC Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Mr. Wruck:

Re: British Columbia Utilities Commission (BCUC, Commission)
Creative Energy Vancouver Platforms Inc. (Creative Energy)
2019-2020 Revenue Requirements Application (RRA) for the
Core Steam System and Northeast False Creek Service Areas (Application)

Creative Energy writes to file its responses to BCUC IR No. 1 in the above noted proceeding, in accordance with Order G-7-20A.

For further information, please contact the undersigned.

Sincerely,

Rob Gorter
Director, Regulatory Affairs and Customer Relations

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CREATIVENERGY

Creative Energy Vancouver Platforms Inc.
2019-2020 Revenue Requirements Application for the
Core Steam System and Northeast False Creek Service Area

CREATIVE ENERGY RESPONSE TO BCUC IR NO. 1

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A. APPLICATION OVERVIEW

1.0 Reference: APPLICATION OVERVIEW
Exhibit B-1 (Application), Section 1, 1.1.1, pp. 1–2; Exhibit B-1-1 (Evidentiary Update), p. 1
Basis for the 2019 Test Year

On page 1 of the Application, Creative Energy Vancouver Platforms Inc. (Creative Energy or CEV) states that it is requesting final approval of 2019 rates, effective January 1, 2029, and also interim and final approval of rates effective January 1, 2020 for the core steam system (Core Steam System) and Northeast False Creek (NEFC) service areas.

On page 2 of the Application, Creative Energy states that the 2019 Revenue Requirements Application (2019 RRA or 2019 Test Year) results are based on "actuals through September 2019 and a forecast of October through December 2019."

On February 21, 2020, Creative Energy filed an Evidentiary Update, providing changes to the Core Steam System and NEFC RRAs for the 2019 and 2020 Test Years. Creative Energy also provided updated tables from the Application that "consequently require updating as implicated by the Evidentiary Update."

Section 59-60 of the Utilities Commission Act requires the BCUC to establish rates that are not unjust, unreasonable, or unduly discriminatory.

1.1 Please confirm, or explain otherwise, that the amounts provided in the Evidentiary Update for the 2019 RRA now represent 12 months of Actual results for the Core Steam System and NEFC, respectively.

RESPONSE:

The Evidentiary Update for the 2019 RRA is based on 12 months of unaudited actual 2019 results for the Core Steam and NEFC systems of Operating and Maintenance (O&M) expense and load, and

updates for actual municipal access fees and property taxes. Increases to Plant in Service and Rate Base and the corresponding calculated values of the revenue requirement including income taxes, return on equity, interest expense and amortization are projected values, as based in part on corresponding projected regulated amounts.

1.1.1 If not confirmed, please confirm the number of months of Actual and Forecast included in the 2019 RRAs for the Core Steam System and NEFC, respectively, and provide a breakdown between Actual and Forecast for all financial schedules. Please also explain the methodology for determining the Forecast amounts.

RESPONSE:

Please refer to the response to BCUC IR 1.1.

1.2 It is general practice for the British Columbia Utilities Commission (BCUC) to establish rates for a public utility on a prospective basis (for example, based on forecast cost of service). Given that Creative Energy is now reporting (some, if not, all) Actuals for the 2019 RRA (which have not been previously approved by the BCUC), please discuss what considerations this Panel must make in order to approve rates for 2019 in accordance with its mandate under the UCA.

RESPONSE:

Creative Energy fully understands the general practice of the BCUC to establish rates for a public utility on the basis of utility revenue requirements filed on a test year plan basis.

For additional context to the current circumstances, the approach to filing for final 2019 rates on a test year basis is unique, in part due to a BCUC decision in October 2018 denying Creative Energy's application for a multi-year index based ratemaking mechanism for the 2018-2020 period and noting that interim rates effective for 2019 were approved shortly thereafter, necessitating a revenue requirement application or applications for 2019 and 2020 rates. Additionally, Creative Energy had resource constraints earlier in 2019 related in part to its operational and regulatory response to very high fuel costs during the winter of 2018/2019. The effect of the circumstances overall was an ultimate decision by Creative Energy to file a single Application for the two-year period 2019-2020. Creative Energy also confirms that it has filed for approval of 2020 rates on a forward-looking test year plan basis and intends to file for future year rates also on that basis in the normal course.

Although the timing of the filing for final 2019 rates is uncommon, Creative Energy does not consider that review and approval of final 2019 rates presents any extraordinary considerations for the Panel outside of its existing mandate under the UCA to ensure that Creative Energy's ratepayers receive safe, reliable and non-discriminatory energy services at just and reasonable rates, and that shareholders are afforded a reasonable opportunity to earn a fair return on their invested capital.

1.3 Please provide examples in other jurisdictions in which public utilities have sought approval of energy rates using Actual results. What considerations did regulators make in those cases, and what did they decide?

RESPONSE:

Creative Energy does not propose that the Commission should approach its review of 2019 final rates differently than it would review a revenue requirements application in the normal course.

Accordingly, Creative Energy has not researched any examples of other approaches used in other jurisdictions in which public utilities might typically seek approval of rates based on actual results. As noted in the response to BCUC IR 1.2, Creative Energy acknowledges that it is not typical, but that it should not impede the BCUC's review of Creative Energy's application for final 2019 rates, which Creative Energy considers to be reasonable for the reasons it has set out in its Application.

B. CORE STEAM SYSTEM

2.0 Reference: APPLICATION OVERVIEW
Exhibit B-1, Section 1.1.1, 1.1.1.3, pp. 3, 5; Exhibit B-1-1, pp. 1–3; Appendix 1, p, 2; Evidentiary Update Schedules for RRA Filing, Core Schedule 13
2019 Revenue Requirements - Summary

On page 5 of the Application, Creative Energy states, "[t]he 2019 RRA mirrors 2019 Projected results, with the exception that the 2019 RRA incorporates the allowed ROE of 9.5 percent into the determination of the required average rate and specifically targets maintaining 2019 rates equivalent to 2018 rates". [*Emphasis Added*]

On page 1 of the Evidentiary Update, Creative Energy states, "Beyond the discussion below of each of the changes reflected in this Evidentiary Update, the substantive narrative and variance explanations provided in the Application remain current and no revisions are required in that regard."

Table 2 on page 3 of the Evidentiary Update shows that Municipal Access Fees for the 2019 RRA and 2019 Projected results are $268,387 and $268,459, respectively.

2.1 Please explain why Municipal Access Fees in the 2019 RRA do not "mirror" 2019 Projected results after the Evidentiary Update.

RESPONSE:

Municipal Access Fees in the 2019 RRA do "mirror" the 2019 Projected results after the Evidentiary Update, noting that an adjustment was made to the calculation of Municipal Access Fees in the Evidentiary Update to account for a $0.41 per MBTU adjustment, as explained in the response to BCUC IR 16.1 and Attachment 16.2-B.

2.1.1 Please provide revised financial schedules for the Core Steam System and errata to the Application or Evidentiary Update, as appropriate.

RESPONSE:

Not applicable. Please refer to the response to BCUC IR 2.1.

In the footnote to Table 2 on page 3 of the Application, Creative Energy states that the 2019 RRA (i.e. 2019 Test Year) revenue collected is less than the revenue required as it "reflects the proposal to set 2019 rates equal to the interim approved level of $7.65 [per thousand pounds of steam] given projected load and to concurrently record an addition to the Third-Party Regulatory Costs Deferral Account in the amount of the difference of ($45,742) for recovery through the DARR [Deferral Account Rate Rider] beginning in 2020." [*Emphasis Added*]

On page 3 of the Evidentiary Update, Creative Energy states that the amount of the revenue deficiency at the proposed rates is increased to $85,241 from $45,742 "for the same reasons as discussed in the

footnote to Table 2 of the Application…".

2.2 Please explain why Creative Energy proposes to maintain 2019 permanent rates at 2019 interim rates given the forecast revenue deficiency of $85,241.

RESPONSE:

Creative Energy understands that if the BCUC was to order that 2019 final rates shall be increased from the level of the interim rates, effective January 1, 2019, Creative Energy would be required to immediately bill customers to recover the difference between what they were charged under 2019 interim rates and what Creative Energy is required to charge them under the higher 2019 final rates ordered by the BCUC. Creative Energy considers that a more typical approach is to recover the revenue deficiency in 2019 (that is, the deficiency between the final approved 2019 revenue requirement and the revenue pursuant to interim 2019 rates) prospectively through a rate rider as Creative Energy has proposed.

Creative Energy highlights that the mechanics and rationale of this approach is also as described in the footnote to Table 2 of the Application and the associated references to sections 1.1.1.2 and 1.1.1.3. That discussion reflects the proposal to set 2019 rates equal to the interim approved level of 7.65/M# and to concurrently record an addition to the Third-Party Regulatory Costs Deferral Account (TPRCDA) to recover, through the DARR, the 2019 revenue deficiency at the 2019 proposed rates, which is driven in large part by extraordinary regulatory cost pressures in 2019, including:

- **As summarized in section 1.1.1.3 for example, and reflected in Tables 27 and 29 of the Application, Creative Energy projected at least an additional $178,000 of regulatory costs over forecast, related in part to the actual costs of the ongoing Commission review of the Beatty Redevelopment CPCN that extended through 2019 into the Specified Scope as set by the Panel in that proceeding; and**

- **The Commission's 2019 proceeding into the review of very high fuel costs in the Winter of 2018/2019 was also a result of unplanned, extraordinary circumstances.**

Thus, given that the revenue deficiency of $85,241 is materially less than the additional un-forecast regulatory costs, and for the same reasons as set out in the Application to record the initial estimated revenue deficiency of $45,742, Creative Energy considers it to be reasonable to maintain 2019 permanent rates at 2019 interim rates and to record the revenue deficiency of $85,241 to the TPRCDA for recovery through the DARR.

2.2.1 Please provide, with supporting calculations, what the 2019 permanent rate increase would be in order to recover the 2019 revenue deficiency of $85,241.

RESPONSE:

The increase in the 2019 permanent rate in order to recover the 2019 revenue deficiency of $85,241 would be 1 percent, as shown below.

2018 Approved Revenue Requirement	8,402,753
2018 Approved Load	1,098,514
Average Rate	7.65
2019 Actual Revenue	8,614,359
2019 Revenue Deficiency	85,241
2019 Revenue Requirement	8,699,600
2019 Actual Load	1,126,060
Average Rate	7.73
Increase in Average Rate	0.08
Increase in Permanent Rate = (.08/7.65)	1.0%

2.3 Please confirm, or explain otherwise, that the proposed addition of $85,241 to the Third-Party Regulatory Costs Deferral Account (TPRCDA) relates to "incorporating" an allowed Return on Equity (ROE) of 9.5 percent into the 2019 revenue requirement.

RESPONSE:

Confirmed. Please refer to the responses to BCUC IRs 1.1, 2.2, 2.4 and 2.5.

The following is a BCUC staff extract from Table 2 on page 3 of the Evidentiary Update showing the 2018 Approved, 2019 Projected, and 2019 and 2020 Test Year return on equity (ROE) in dollars and percentage terms:

Core Revenue Requirements Summary ($)	2018	2019	2019	2020
Cost or Rate Component	Approved	Projected – Update	RRA – Update	RRA – Update
Return on Equity	1,053,026	938,687	1,024,000	1,063,000
ROE	9.5%	8.7%	9.5%	9.5%

2.4 Please explain whether the 2019 Projected ROE of $938,687, or 8.7 percent, shown in Table 2 of the Evidentiary Update is based on 12 months of Actual results. If not, please explain how many months of Actual results are included.

RESPONSE:

The 8.7 percent is based on 12 months of actual results for O&M and revenue, while the 9.5 percent in the 2019 Update column reflects recovery of the revenue deficiency resulting from the higher costs in 2019, notably the higher regulatory costs as explained in the response to BCUC IR 2.2 above.

2.5 Given that Creative Energy now has (at least) 9 months of Actual ROE data, please discuss whether the approval of the requested ROE in this Application is equivalent to seeking a guarantee, as opposed to an opportunity, to earn its allowed ROE for 2019.

RESPONSE:

Creative Energy considers that by determining the final 2019 rates and the amount to be recorded to the DARR for recovery, the Commission will effectively determine Creative Energy's actual ROE for 2019. This is because Creative Energy's steam sales and O&M costs for 2019 are known. This is not a

situation where actual load might vary from an approved forecast or where actual O&M costs might vary from an approved plan; actual load and actual O&M costs are known as reported in the Evidentiary Update.

Creative Energy has also highlighted in the Application that its proposal to maintain 2019 final rates equal to the interim approved 2019 rates and to recover a portion of the extraordinary regulatory costs through the DARR reflects a fair and beneficial sharing of the higher than forecast actual load in 2019. That is, given the timing of its Application for 2019 rates Creative Energy is not seeking a rate increase that may have otherwise been defended by proposing a 2019 rate increase on the basis of recovering its projected 2019 cost of service under a lower load forecast that ought to be expected in an average year, such as the load forecast most recently approved in 2018, which is lower than 2019 actual load.

2.5.1 Please provide other jurisdictional examples to support your response.

RESPONSE:

Creative Energy is not clear what examples would be relevant to the BCUC's IR 2.5. In any case, Creative Energy has not researched the approaches of other regulators in other jurisdictions in connection with this Application. Please refer to the response to BCUC IR 1.3.

The following is a BCUC staff extract of Table 2 on page 3 of the Evidentiary Update showing the 2018 Approved, 2019 Projected, and 2019 and 2020 Test Year capital structure:

Table 2 Update: Core Revenue Requirements – Summary

Core Revenue Requirements Summary ($)	2018	2019	2019	2020
Cost or Rate Component	Approved	Projected – Update	RRA – Update	RRA – Update
Rate of Return Summary				
Rate Base	25,603,229	25,367,554	25,368,211	26,330,358
Debt	14,721,857	14,586,343	14,586,721	15,139,956
Equity	10,881,372	10,781,210	10,781,490	11,190,402

Lines 10-12 in Core Schedule 13 from the Financial Schedules attached to the Evidentiary Update shows the following capital structure for the 2019 and 2020 Test Years:

Schedule 13		2019	2020
Line #	Item	Test Year	Test Year
9	CAPITAL STRUCTURE $		
10	Equity	10,777,322	11,188,167
11	Long term Debt	9,306,535	9,661,311
12	Short Term Debt	5,274,548	5,475,620
13	Total	25,358,405	26,325,098

2.6 Please confirm whether the 2019 Test Year and 2020 Test Year debt is $14,586,721 and $15,139,956, respectively, as shown in Table 2 or $14,581,083 ($9,306,535 + $5,274,548) and $15,136,931 ($9,661,311 + $5,475,620), respectively, as shown in Core Schedule 13.

RESPONSE:

The correct values are the amounts of $14,581,083 and $15,136,931, corresponding to Schedule 13. Please refer to an updated Table 2 below.

Table 2 Update: Core Revenue Requirements – Summary

Core Revenue Requirements Summary ($)	2018	2019	2019	2020
Cost or Rate Component	Approved	Projected – Update	RRA – Update	RRA – Update
O&M - Total	4,475,257	4,934,103	4,934,103	5,126,308
Wages and Benefits (Steam, Distribution & Management)	2,692,446	2,745,630	2,745,630	2,992,604
Water-related and Electricity Expenses	776,350	900,422	900,422	991,046
Maintenance and related functional Operations	487,994	525,878	525,878	499,108
Special Services (Regulatory, Audit, Legal, Consultant)	233,315	487,878	487,878	313,215
Other General & Administration & Sales Expense	285,152	274,295	274,295	330,335
Municipal Access Fee	258,887	268,459	268,387	278,071
Property Taxes	595,160	663,826	663,826	763,300
Income Taxes	275,579	279,700	279,700	283,400
Depreciation	1,010,151	944,584	944,584	971,284
Interest Expense	600,856	585,000	585,000	608,000
Return on Equity	1,053,026	938,687	1,024,000	1,063,000
Total Return on Rate Base	1,653,882	1,551,594	1,609,000	1,671,000
Subtotal	8,268,916	8,614,359	8,699,600	9,093,363
Approved amort. of deferred Reg. and Pension expenses in steam rate	133,837	n/a	n/a	n/a
Amortization of deferred Regulatory and Pension expenses in DARR	n/a	n/a	n/a	331,097
Revenue	8,402,753	8,614,359	8,614,359	9,424,460
Rate Summary				
Steam Load M#	1,098,514	1,126,060	1,126,060	1,140,634
Average Steam Rate $/M#	7.65	7.64	7.65	7.97
Average Steam Rate % increase	n/a	n/a	0.0%	4.2%
Deferral Account Rate Rider (DARR) $/M#	n/a	n/a	n/a	0.29
DARR % rate impact	n/a	n/a	n/a	3.8%
Rate of Return Summary				
Rate Base	25,603,229	25,367,554	25,358,405	26,325,100
Debt	14,721,857	14,586,343	14,581,083	15,136,531
Equity	10,881,372	10,781,210	10,777,322	11,188,167
Debt %	57.5%	57.5%	57.5%	57.5%
Equity %	42.5%	42.5%	42.5%	42.5%
Weighted Average Cost of Debt	4.1%	4.0%	4.0%	4.0%
ROE	9.5%	8.7%	9.5%	9.5%

2.6.1 Please provide revised financial schedules for the Core Steam System and errata to the Evidentiary Update, as appropriate.

RESPONSE:

The Financial Schedules as provided in the Evidentiary Update are correct. Please refer to the response to BCUC IR 2.6 for an updated Table 2.

2.7 Please confirm whether the 2019 Test Year and 2020 Test Year equity is $10,781,490 and $11,190,402, respectively, as shown in Table 2 or $10,777,322 and $11,188,167, respectively, as shown in Core Schedule 13.

RESPONSE:

The correct values are the amounts of $10,777,322 and $11,188,167 as shown in Schedule 13. Please refer to the response to BCUC IR 2.6 for an updated Table 2.

2.7.1 Please provide revised financial schedules for the Core Steam System and errata to the Evidentiary Update, as appropriate.

RESPONSE:

The Financial Schedules in the attachment provided with the Evidentiary Update are correct. Please refer to the response to BCUC IR 2.6 for an updated Table 2.

On page 5 of the Application, Creative Energy states that its "intent is to maintain smooth and predictable rate increases over the entire 2019 to 2020 period while allowing it to recover its cost of service under business as usual conditions in response to inflationary pressures and with a fair opportunity to earn its allowed ROE. Accepting the removal of an otherwise beneficial sharing of the load impact in 2019 allows Creative Energy to put in place this objective". [*Emphasis Added*]

2.8 Please explain the statement, "[a]ccepting the removal of an otherwise beneficial sharing of the load impact in 2019", considering that Creative Energy does not have a load variance deferral account.

RESPONSE:

The statement is intended to reflect that Creative Energy determined it was reasonable at the time of the Application to propose final 2019 rates on the basis of its projected load at that time (projected 2019 load was, at that time, based on actuals through September 2019 and a forecast of October through December 2019) – rates that were thus lower than what otherwise would have been the case if determined on the basis of a lower load forecast that would normally be expected in an average year, such as the approved load forecast in 2018.

On page 2 of Appendix 1 to the Evidentiary Update, Creative Energy provides the following table showing a summary of component rate increases and variances in the 2019 and 2020 Test Year compared to 2018 Approved:

Table 4 Update: Core Revenue Requirements – Summary of Component Rate Increase and Variance from 2018 Approved to 2020 RRA

2020 Rate Increase Components				
Cost Component	General Category of Cost Control	2018 Approved to 2019 RRA	Explanatory Variance of Overall Steam Rate Increase: 2018 Approved to 2020 RRA	
O&M		458,846	651,051	7.7%
Wages and Benefits (Steam, Distribution & Management)		23,454	247,923	3.0%
	External	29,731	52,235	0.6%
Water-related expenses (Fees, treatment, electric service)		-	-	0.0%
	External	124,072	214,697	2.6%
Maintenance (including parts, supplies, safety and vehicles)		37,884	11,114	0.1%
	External	-	-	0.0%
Special Services (Regulatory, Audit, Legal, Outside Services)		48,579	49,563	0.6%
	External	205,983	30,336	0.4%
Other General & Administration (e.g. insurance, office)		(51,381)	(3,377)	0.0%
	External	41,987	48,560	0.6%
Municipal Access Fee	External	9,500	19,184	0.2%
Property Taxes	External	68,666	168,140	2.0%
Income Taxes	External	4,121	7,821	0.1%
Depreciation	External	(65,567)	(38,867)	-0.5%
Interest Expense	External	(15,856)	7,144	0.1%
Return on Equity	External	(29,026)	9,974	0.1%
Summary				
Amortization of deferred Regulatory and Pension expenses in steam rate			(133,837)	-1.6%
Controllable Costs as generally understood		34,098	305,222	3.6%
Externally Driven Costs as generally understood		421,708	519,225	6.2%
Load M#			42,120	-4.0%
Total Steam Rate Increase 2020				4.2%

2.9 Please confirm, or explain otherwise, that the two categories of cost control represented in Table 4 under the "General Category of Cost Control" column are: a) controllable costs; and b) external or externally driven costs.

RESPONSE:

Confirmed, although Creative Energy did qualify the labelling of these descriptors in section 3.2.2 of the Application to properly set the context for their interpretation, as follows:

> **… To assist this discussion, cost drivers are further grouped according to a qualitative assessment of where management is generally able to exercise budgeting control and decision-making and where operating costs are commonly understood to be within the scope of management control, as compared to where costs are more largely determined outside Creative Energy (e.g., rates applicable to Creative Energy's water, electricity and natural gas consumption). Creative Energy would caution, however, that this categorization should not be considered as precise. The categorization is intended to provide insight and understanding of the drivers for the variances between the 2020 test year and 2018 Approved levels.**

Thus, Creative Energy has labelled both overall categories, Controllable Costs and Externally Driven Costs, "as generally understood."

Also, to shorten the labelling in other tables of the Application for ease of formatting, the "Controllable Costs as generally understood" were interchangeably labelled "Not external".

2.9.1 For each cost component, please explain how Creative Energy classifies its costs into the categories of cost control (i.e. controllable costs, and external or externally driven costs).For example, why are is there a component of external or externally driven costs for Wages and Benefits considering that Creative Energy is a party to union negotiations?

RESPONSE:

Additional clarity on the categorization of costs is as follows:

- **The only external cost categorization under 'Wages and Benefits' are pension-related costs, while wages, overtime and benefits are categorized as generally controllable;**
- **Water fees, water treatment costs and electricity costs are all externally set and vary with load;**
- **Maintenance costs are considered overall as under management control even though a specific driver of required maintenance may at times be an external event;**
- **Special services in relation to regulatory costs and audit fees are categorized as external and outside legal fees and consultants are considered as generally controllable (although the latter might possibly be debatable year over year depending on the specific driver of work need and any related decisions to manage peak work requirements externally versus internally); and**
- **General and Administration Costs are categorized as generally controllable in relation to office-related expenses, such as supplies, phones and information technology, as well as directors' fees, sales expense and WCB-related costs, while externally driven amounts relate to insurance, permits and bank charges.**

2.10 Please confirm, or explain otherwise, for both variances in the 2019 and 2020 Test Year, compared to 2018 Approved, that: a) the sum of all cost variances which are "blank" in the

"General Category of Cost Control" column should equal the "Controllable Costs as generally understood" in the summary portion of the table; and b) the sum of all cost variances which are classified as "External" in the "General Category of Cost Control" column should equal the "Externally Driven Costs as generally understood" in the summary portion of the table.

RESPONSE:

Confirmed; however, noting now two items:

1. **The net total of controllable costs was missed being manually updated in the Appendix 1 document of the Evidentiary Update for the '2018 Approved to 2019 RRA' comparison; and**

2. **The net total of the Externally driven costs for the '2018 Approved to 2019 RRA' comparison was computing incorrectly as explained by a formula referencing typo of the word 'External' that had the effect of excluding from the net total the external costs of the items reported in Table 4 that are not O&M expenses.**

These items are corrected in the table provided in the response below to BCUC IR 2.10.1.

2.10.1 If confirmed, please provide a revised Table 4 (i.e. errata to the Evidentiary Update) correcting the amounts shown for "Controllable Costs as generally understood" and "Externally Driven Costs as generally understood" for the 2019 Test Year compared to 2018 Approved.

RESPONSE:

Please refer to the following table.

2020 Rate Increase Components				
Cost Component	General Category of Cost Control	2018 Approved to 2019 RRA	Explanatory Variance of Overall Steam Rate Increase: 2018 Approved to 2020 RRA	
O&M		458,846	651,051	7.7%
Wages and Benefits (Steam, Distribution & Management)	Not External	23,454	247,923	3.0%
	External	29,731	52,235	0.6%
Water-related expenses (Fees, treatment, electric service)	Not External	-	-	0.0%
	External	124,072	214,697	2.6%
Maintenance (including parts, supplies, safety and vehicles)	Not External	37,884	11,114	0.1%
	External	-	-	0.0%
Special Services (Regulatory, Audit, Legal, Outside Services)	Not External	48,579	49,563	0.6%
	External	205,983	30,336	0.4%
Other General & Administration (e.g. insurance, office)	Not External	(52,844)	(3,377)	0.0%
	External	41,987	48,560	0.6%
Municipal Access Fee	External	9,500	19,184	0.2%
Property Taxes	External	68,666	168,140	2.0%
Income Taxes	External	4,121	7,821	0.1%
Depreciation	External	(65,567)	(38,867)	-0.5%
Interest Expense	External	(15,856)	7,144	0.1%
Return on Equity	External	(29,026)	9,974	0.1%
Summary				
Amortization of deferred Regulatory and Pension expenses in steam rate			(133,837)	-1.6%
Controllable Costs as generally understood		57,073	305,222	3.6%
Externally Driven Costs as generally understood		373,611	519,225	6.2%
Load M#			42,120	-4.0%
Total Steam Rate Increase 2020				4.2%

On page 2 of Appendix 1 to the Evidentiary Update, Creative Energy provides the following table showing a summary of the incremental factors impacting the 2020 Steam Rate increase compared to 2018 Approved:

Table 3 Update: Incremental Factors impacting 2020 Steam Rate Increase compared to 2018 Approved

Summary	Applicable Amount ($)	% of Rate Impact (2018-2020)
Amortization of deferred Regulatory and Pension expenses in steam rate	(133,837)	-1.6%
Controllable costs as generally understood	305,222	3.6%
Externally Driven Costs as generally understood	519,225	6.2%
Load M#	42,120 M#	-4.0%
Total Core Steam Rate Increase 2020		4.2%

2.11 Please explain how the "% of Rate Impact" amounts as shown in Tables 3 and 4 of the Evidentiary Update were calculated and provide the calculations in an Excel spreadsheet.

RESPONSE:

The calculations are explained in the table below, and in which respect an accompanying Excel spreadsheet is not required.

2018 Approved RRA $	8,402,753	(1)
2018 Approved Load Forecast M#	1,098,514	(2)
2018 Average Rate $/M#	7.65	(3)
2020 Proposed Load Forecast M#	1,140,634	(4)
2020 Average Rate $/M#	7.97	(5)
Variance of 2018 Approved RRA to 2020 RRA		
Amortization of deferred Regulatory and Pension expenses in steam rate	(133,837)	(6)
Controllable costs as generally understood	305,222	(7)
Externally Driven Costs as generally understood	519,225	(8)
Load M#	42,120	(9)
% of Rate Impact (2018-2020)	**%**	**calculation**
Amortization of deferred Regulatory and Pension expenses in steam rate	-1.6%	(10) = (6)/(1)
Controllable costs as generally understood	3.6%	(11) = (7)/(1)
Externally Driven Costs as generally understood	6.2%	(12) = (8)/(1)
Load M# (i.e. the rate impact explained by the net increase in load)	-4.0%	(13) = [-(9)*(5)]/[(2)*(3)]
Net Core Steam Rate Increase 2020 compared to 2018	4.2%	(14) = sum[(10)(11)(12)(13)]

3.0 Reference: APPLICATION CONTEXT
Exhibit B-1, Section 2.1, 2.2.1, pp. 15–17
Direct Allocation of Time to Capital versus Expense

On page 15 of the Application, Creative Energy provides the following list of its thermal energy systems (TES) in Vancouver (planned or in-service):

Table 7: Creative Energy Thermal Energy Systems in Vancouver, Planned or In-service

Vancouver Projects	TES Type	Status	Entity
Core Steam	Stream B	In-service	CEV
NEFC	Stream B	In-service	CEV
Main & Keefer	Stream A	In-service	CEV
Kensington Gardens	Stream A	In-service	CEV
South Downtown Heating TES	Stream B	In-service	CEV
South Downtown Cooling TES	Stream B	Subject to approval	CEV
Pendrell Heating	Stream A	In-service	CE Pendrell LP
Horseshoe Bay Heating	Stream A	Planned	CEDLP
Main & 5th Cooling	Stream B	Planned	CEDLP
Cambie Thermal - Corix Partnership	Stream B	Planned	CEDLP

3.1 Please identify which TES projects included in Table 7 are new projects that Creative Energy has planned or put in-service since the filing of its last Revenue Requirements Application.

RESPONSE:

Creative Energy's 2018-2022 RRA was filed on December 1, 2017. The following TES in Table 7 are planned or have been put in-service since that time:

- **South Downtown Heating TES (noting that a Stream A was approved prior to December 1, 2017 for construction heat at this location);**
- **South Downtown Cooling TES;**
- **Pendrell Heating;**
- **Horseshoe Bay Heating;**
- **Main & 5th Cooling; and**
- **Cambie Thermal.**

3.1.1 Please discuss whether there are any TES projects not included in Table 7 which Creative Energy previously had planned but decided not to go forward with since the filing of its last Revenue Requirements Application. If yes, please provide the amounts that were written-off and the impact on Steam Rates, if any.

RESPONSE:

An affiliate of Creative Energy had planned to move forward with a Heating TES at a location near Alberni and Cardero streets in Vancouver. A Stream B CPCN application was submitted to the BCUC for that TES project in 2019 but withdrawn when one proponent/future customer terminated a connection agreement. The Creative Energy affiliate is still evaluating that TES project to serve the remaining proponent, and as applicable will file a Stream A or Steam B application as required.

Creative Energy notes however that all TES project development and capital costs, including related to Creative Energy Vancouver staff time, are all directly assigned and capitalized to each TES project, in most cases in an affiliate, and have no impact on Core Steam rates, whether the project proceeds or not. Such is the case also for the Alberni TES project described above.

In footnote 6 on page 17 of the Application, Creative Energy states:

> Pendrell [Heating] received Stream A approval under the CEDLP [Creative Energy Developments Limited Partnership] entity, but Creative Energy will be transferring ownership to a separate regulated limited partnership entity to ensure the proper separation of its activities from non-regulated CEDLP activities.

3.2 Please provide the expected timing of the application to the BCUC to transfer ownership of Pendrall Heating from CEDLP to "CE Pendrall LP".

RESPONSE:

An application was filed with the Commission on March 17, 2020 requesting approval for Creative Energy Developments LP to dispose of its interest in the Pendrell Street TES to its wholly-owned subsidiary, Creative Energy Pendrell LP.

On page 16 of the Application, Creative Energy provides the following table showing the forecast allocation of Creative Energy staff time between CEV and CEDLP and the direct assignment of forecast time to CEV that will be capitalized:

Table 8: 2020 Budgeted Time Allocation and Project Assignment by Role

	Time Allocation		Creative Energy Vancouver Platforms				
	Creative Energy Vancouver Platforms	Creative Energy Developments Limited Partnership	Project Assignment			Net Expense Assignment to Core RRA	
			Direct Assignment to CEV Projects (Capitalized)	Expensed to CEV	Net CEV Expense	Direct Assign-ment	Mass. Form.
Chief Executive Officer	50%	50%	0%	100%	50%	n/a	Yes
VP, Engineering & Projects	40%	60%	80%	20%	8%	n/a	Yes
VP, Business Development	0%	100%	n/a	n/a	0%	n/a	n/a
Chief Financial Officer	30%	70%	0%	100%	30%	n/a	Yes
Director, Regulatory Affairs	80%	20%	0%	100%	80%	n/a	Yes
Director, Operations	100%	0%	0%	100%	100%	n/a	Yes
Director, Engineering (planned)	40%	60%	80%	20%	8%	n/a	Yes
Mgr. Corporate Development	60%	40%	0%	100%	60%	n/a	Yes
Construction Manager	100%	0%	80%	20%	20%	n/a	Yes
Project Engineer	0%	100%	n/a	n/a	0%	n/a	n/a
Project Engineer	0%	100%	n/a	n/a	0%	n/a	n/a
Project Engineer (planned)	0%	100%	n/a	n/a	0%	n/a	n/a
Controller	70%	30%	0%	100%	70%	n/a	Yes
Accountant	80%	20%	0%	100%	80%	n/a	Yes
Accountant	40%	60%	0%	100%	40%	n/a	Yes
Office Coordinator	60%	40%	0%	100%	60%	n/a	Yes
Chief Engineer Steam Plant	100%	0%	0%	100%	100%	Yes	n/a
Steam Plant Crew (11)	100%	0%	0%	100%	100%	Yes	n/a
Distribution Lead	97%	3%	0%	100%	97%	Yes	n/a
Distribution Crew (6)	97%	3%	0%	100%	97%	Yes	n/a

3.3 Please elaborate on the percentage allocations between CEV and CEDLP shown in the "Time Allocation" column. How were the allocations developed by the Management team (e.g. historical timesheets, estimates, other)?

RESPONSE:

The factors considered when developing the budgeted allocation for the Management team were review of historical timesheets, analysis of budgets for specific capital projects, discussions with employees, and discussions with management.

3.3.1 Please clarify to which entity the time spent on the Pendrell Heating project is allocated (i.e. Creative Energy or CEDLP).

RESPONSE:

Time spent on the Pendrell Heating project will be allocated to Creative Energy Pendrell LP, a wholly owned subsidiary of CEDLP.

3.3.2 Please explain whether time allocated to CEDLP has any impact on the costs of Creative Energy, considering that CEDLP is a partnership between Creative Energy Canada Platforms Inc. (Creative Energy's parent company) and Emanate Energy Solutions Inc.

RESPONSE:

Time allocated to CEDLP has no impact on the costs of Creative Energy. Employees providing services to CEDLP prepare timesheets and their full costs are directly billed to CEDLP.

3.4 Under the "Creative Energy Vancouver Platforms" column heading, please explain what each sub-column heading (i.e. Direct Assignment to CEV Projects, Expensed to CEV, and Net CEV Expense) is and how each of the sub-column percentages is determined.

RESPONSE:

Direct assignment to CEV Projects (Capitalized): CEV employees spend time supporting capital projects for the Core system (maintenance capex and customer connections) and other energy systems within CEV (NEFC, South Downtown, Kensington, Main & Keefer). They directly charge their time to these projects and their costs are capitalized to those projects. The percentages are determined in the same manner as explained in the response to BCUC IR 3.3, with a view also the specific responsibilities of the corresponding employee role.

Expensed to CEV: These are the percentage of costs that employees spend on CEV that are not capitalized to projects. The total of these costs is shared between the Core steam system, NEFC, South Downtown, Kensington and Main & Keefer. They are allocated to these energy systems based on the Massachusetts formula. The percentages are determined in the same manner as explained in the response to BCUC IR 3.3, with a view also the specific responsibilities of the corresponding employee role.

Net CEV expense: The percentages in this column are equal to 'Time Allocation – Creative Energy Vancouver Platforms' multiplied by 'Project Assignment – Expensed to CEV.

Net Expense Assignment to Core RRA – Direct Assignment: Operating energy systems within CEV such as NEFC, South Downtown, Kensington and Main & Keefer are serviced by a shared plant and distribution team. These employees fill out timesheets and their costs are coded directly to those energy systems.

Net Expense Assignment to Core RRA – Mass. Form.: Management and administration staff do not work directly on energy systems once they are operating. Management and administration expenses are allocated using the Massachusetts Formula instead of timesheets.

3.5 Please explain the last two columns in the Table 8. How does Creative Energy determine which employee costs are directly assigned and which should apply the Massachusetts formula? How are the results of this analysis used in Table 9 of the Application?

RESPONSE:

Please refer to the responses to BCUC IRs 3.3 and 3.4. The last two columns in Table 8 are imputed from all prior columns of Table 8, with the exception as indicated by the last four rows of Table 8 that labour and expenses directly supporting the steam plant and steam distribution network are almost entirely directly assigned to those functions.

Thus, for example, the cost of management and accounting staff time allocated to Creative Energy Vancouver will be allocated across all projects in operation based on the Massachusetts formula allocation ratios, while those allocation are "not applicable" for any staff that are supporting entirely the projects under development by CEDLP (i.e. those staff whose time is noted as 100% applicable to CEDLP, the costs of which are entirely directly assigned to specific projects under development and not included in the total of remaining costs allocated through the Massachusetts formula).

4.0 Reference: APPLICATION CONTEXT
Exhibit B-1, Section 2.2.1, p. 17
Assignment of Net Expenses using the Massachusetts Formula

On page 17 of the Application, Creative Energy provides the following table showing the application of the Massachusetts Formula based on the proposed two-factor and existing three-factor allocation methods:

Table 9: Massachusetts Formula: 3 Factor versus 2 Factor

	Core	NEFC	Main & Keefer	Kensington Garden	SODO Heating	SODO Cooling[5]	Pendrell[6]	Total
Factor ($)								
Capital	25,665,155	4,851,398	781,427	1,865,605	3,752,214	1,418,054	1,254,230	39,588,083
Revenues	9,087,307	1,581,195	135,544	341,167	418,675	159,541	167,156	11,890,586
Plant & Dist. Labour	2,228,989	51,691	19,384	77,536	51,691	12,737	25,845	2,467,874
Ratio								
Capital	65%	12%	2%	5%	9%	4%	3%	100%
Revenues	76%	13%	1%	3%	4%	1%	1%	100%
Plant & Distribution Labour	90%	2%	1%	3%	2%	1%	1%	100%
Combined Ratio: 3 Factor	77.2%	9.2%	1.3%	3.6%	5.0%	1.8%	1.9%	100%
Combined Ratio: 2 Factor	83.4%	7.7%	1.0%	3.0%	2.8%	0.9%	1.2%	100%
3-Factor Allocation	1,211,978	144,695	20,407	56,123	78,995	28,470	29,420	1,570,089
2-Factor Allocation	1,309,019	120,837	15,115	47,189	44,085	14,585	19,258	1,570,089
Difference	97,041	-23,857	-5,292	-8,934	-34,910	-13,885	-10,162	-

On page 17 of the Application, Creative Energy states the "combined ratio for each project is applied to the total General and Administrative costs of CEV to determine the amounts to be allocated to each project."

4.1 Please confirm, or explain otherwise, that the source of the data highlighted in red in the table above is the 2020 Test Year.

RESPONSE:

Confirmed.

4.1.1 If confirmed, please provide the following, including a revised Table 9 as an erratum to the Evidentiary Update if needed:

i. References to the supporting Core Steam System and NEFC Financial Schedule(s) attached to the Evidentiary Update in which each amount can be found (i.e. schedule number and Excel cell reference); and

ii. A reconciliation of the account numbers and amounts shown in Core Schedule 15 (from the Financial Schedules attached to the Evidentiary Update) to the total amount allocated to the Core Steam System in the 2020 Test Year of $1,211,978, as shown in Table 9.

iii. An explanation for why Creative Energy selected the 2020 Test Year as the source data versus some other data (e.g. 2018 Actuals).

RESPONSE:

i. Please see response below for an updated Table 9 and how it ties into Core Schedule 15 and NEFC Schedule 14.

ii. The intention of this schedule was not to specifically tie into the proposed numbers in the Evidentiary Update and schedules, but to present a directionally consistent illustration of all inputs and calculations to demonstrate the impacts of the alternatives. Table 9 has now been updated below so that the results tie into Schedule 15.

	Core	NEFC	Main & Keefer	Kensington Garden	SODO Heating	SODO Cooling (1)	Pendrell	Total
Factor ($)								
Capital	25,665,155	5,030,828	781,427	1,865,605	3,752,214	1,418,054	1,254,230	39,767,514
Revenues	9,092,370	1,581,195	135,544	341,167	418,675	159,541	167,156	11,895,649
Plant & Dist. Labour	2,228,989	51,691	19,384	77,536	51,691	12,737	25,845	2,467,874
Ratio								
Capital	65%	13%	2%	5%	9%	4%	3%	100%
Revenues	76%	13%	1%	3%	4%	1%	1%	100%
Plant & Distribution Labour	90%	2%	1%	3%	2%	1%	1%	100%
Combined Ratio: 3 Factor	77.1%	9.3%	1.3%	3.6%	5.0%	1.8%	1.9%	100%
Combined Ratio: 2 Factor	83.4%	7.7%	1.0%	3.0%	2.8%	0.9%	1.2%	100%
3-Factor Allocation	1,067,886	129,449	17,960	49,407	69,484	25,039	25,885	1,385,110
2-Factor Allocation	1,154,867	106,562	13,331	41,621	38,881	12,863	16,985	1,385,110
Difference	86,982	-22,888	-4,629	-7,786	-30,603	-12,176	-8,900	0

The balance of $1,154,867 ties into the following balances from Schedule 15.

		Allocated Using Massachussett's Formula?	Core	NEFC
	Administrative & General - Operation			
915	Directors Fees	Yes	41,686	3,847
920	Admin & General Salaries	Yes	676,042	62,380
921	Office Supples & Exp	Yes	104,801	9,670
922	Admin & General Exp	Yes	7,303	674
923	Special Services (Mass. Formula)	Partially	163,215	15,060
923	Special Services (Directly Charged)		150,000	
924	Insurance (Mass Formula)	Partially	67,727	6,249
924	Insurance (Directly Charged)		71,013	-253
925	Injuries & Damages-WCB	Yes	6,520	602
926	Employee Benefits	Yes	87,573	8,081
	Total Allocated Using Mass. Formula		1,154,867	106,562
	Total Directly Charged		221,013	(253)
	Total		1,375,880	106,309

iii. The 2020 Test Year is more applicable than other data sources as new energy systems such as South Downtown Heating and Kensington began operating in 2019 while others such as NEFC added major customers. 2020 will be the first full year of operations for these energy systems.

A key component of the Massachusetts formula is revenues and the most relevant source data for these calculations is 2020 budgeted revenues by energy system.

4.2 Please explain why Pendrell Heating is included in Table 9, considering that this TES project is not operated by Creative Energy (as shown in Table 7 of the Application).

RESPONSE:

Pendrell Heating is included in Table 9 to ensure that the customers of the other TES do not unfairly subsidize the residual general and administrative expenses that are deemed to be fairly allocated to all TES projects, including Pendrell Heating. Where applicable, Creative Energy Vancouver staff are supporting all TES projects whether the projects are owned by Creative Energy Vancouver or separate affiliated LPs.

4.3 Please clarify whether Creative Energy proposes to use the 2-factor Massachusetts Formula in both the 2019 and 2020 Test Year or in only the 2020 Test Year for the Core Steam System.

RESPONSE:

Creative Energy is proposing the use the 2-factor Massachusetts Formula in 2020 and going forward, and not for 2019.

4.3.1 If Creative Energy proposes to use the 2-factor Massachusetts Formula in both the 2019 and 2020 Test Year, please provide (in a similar format to Table 9): i) the calculation of the total amount allocated to the Core Steam System in the 2019 Test Year; and ii) a reconciliation of the account numbers and amounts shown in Core Schedule 15 (from the Financial Schedules attached to the Evidentiary Update) to the total amount allocated to the Core Steam System.

RESPONSE:

Not applicable. Please refer to the response to BCUC IR 4.3.

4.4 Please discuss whether there are other jurisdictions where utilities use the proposed 2-factor Massachusetts Formula based on direct labour expenses and gross revenues to allocate costs.

RESPONSE:

Creative Energy is not aware of other jurisdictions using a 2-factor approach as proposed by Creative Energy. The proposal is based simply on the merits as described in section 2.2.1 of the Application given the unique circumstances and disparate nature of the size and number of customers of the TES projects. Please refer also to the response to CEC IR 7.1.

4.5 Please provide, with supporting calculations, what the percentage increase in Steam Rates would be if the approved 3-factor Massachusetts Formula were used in the 2020 Test Year.

RESPONSE:

If the 3-factor Massachusetts Formula were used in 2020 the average rate would decrease $.07 per M# from the average rate in the Evidentiary Update. As a result, the average rate would increase

3.2% from the 2019 average rate compared to 4.2% if the 2-factor Massachusetts Formula were used.

Difference between 2-factor and 3-factor	(86,982)
Revenue Requirement per Evidentiary Update	9,093,363
Revenue Requirement if 2-factor model is used	9,006,381
Load Forecast per Evidentiary Update	1,140,634
2020 Adjusted Average Rate	7.90
2020 Average Rate per Evidentiary Update	7.97
Difference in Average Rate	(0.07)
% Change from Evidentiary Update	-0.9%
2019 Average Rate	7.65
Difference in Average Rate	0.25
% Change from 2019 Average Rate	3.2%

5.0 Reference: APPLICATION CONTEXT
Exhibit B-1, Section 2.4, pp. 19–20
City of Vancouver - Water and Sewer Charges

On pages 19 to 20 of the Application, Creative Energy states:

> Since 2003, Creative Energy has been exempted from approximately 95 percent of the sewer discharge fees that might otherwise apply given that steam does not go to drain at our plant… if the City [of Vancouver] were to otherwise consider removing the sewer discharge exemption and attempt to recover the allocated costs from Creative Energy directly, Creative Energy's operating costs could increase by approximately $700,000 per year.
>
> Creative Energy continues to assess this risk and to defend the current exemption with the City of Vancouver. While the probability of this cost arising is the very near term is currently low, if it were to arise, Creative Energy would immediately and appropriately bring forward an application to pass through these costs for direct recovery from customers.

5.1 Please provide an update on the assessed risk of the current exemption being removed since the filing of the Application and define "the very near term."

RESPONSE:

Creative Energy considered that the probability of this cost arising in 2020 is low, and it does not yet have an update on the materiality of this risk in future years.

6.0 Reference: CORE STEAM REVENUE REQUIREMENTS
Exhibit B-1, Section 3.1, p. 21
System Load Forecast

On page 21 of the Application, Creative Energy states that the "Steam load may vary plus or minus 10 percent in any given year due to the effect of temperature."

6.1 Please explain, showing calculations, the impact on the revenue requirements and the requested rate increase for the 2020 Test Year under the scenarios that the steam load varies by:

i) Plus 10 percent; and

ii) Minus 10 percent.

RESPONSE:

i) A 10 percent higher load forecast would result in an estimated 4.2 percent decrease in the average rate.

ii) A 10 percent lower load forecast would result in an estimated 14.5 percent increase in the average rate.

	Base Case	10% Increase in Load	10% Decrease in Load
2019 Average Rate	7.65	7.65	7.65
2020 Revenue Requirement	9,093,363	9,193,706	8,993,020
2020 Actual Load Forecast	1,140,634	1,254,697	1,026,571
Average Rate	7.97	7.33	8.76
Increase in Average Rate ($)	0.32	- 0.32	1.11
Increase in Average Rate (%)	4.2%	-4.2%	14.5%

7.0 Reference: CORE STEAM REVENUE REQUIREMENTS
Exhibit B-1-1, Appendix 1, p. 3; Creative Energy 2016-2017 RRA and Rate Design for NEFC Hot Water Decision and Order G-167-16 dated November 18, 2016 (Creative Energy 2016-2017 RRA Decision), p. 54
Total Operations and Maintenance (O&M) Expense

On page 3 of Appendix 1 to the Evidentiary Update, Creative Energy provided Table 14 showing a breakdown of O&M expenses by business function.

On page 54 of the Creative Energy 2016-2017 RRA Decision, it states:

> In future RRAs Creative Energy is directed to use the same capitalized overhead rates for regulatory reporting as it does for financial reporting. It also must provide a table in future RRAs disclosing a five year history of the following: (a) the capitalized overhead rates and amounts used for financial reporting purposes, (b) the forecast and actual capitalized overhead amounts used in the RRA, and (c) the forecast and actual capitalized labour

7.1 Given that Creative Energy previously confirmed 2016 and 2017 Actual O&M expenses allocated to capital, of $18,638 and $20,100 respectively, during the Creative Energy 2018-2022 RRA proceeding,[1] please explain why no capitalized amount is shown for 2016 and 2017 in Table 14 of the Evidentiary Update.

[1] https://www.bcuc.com/Documents/Proceedings/2018/DOC_52036_B-12_Creative_Response-IR-2-BCUC.pdf

RESPONSE:

For accounting purposes under Accounting Standards for Private Enterprises (ASPE), overhead cannot and has not been capitalized. O&M expenses are considered overhead for accounting purposes. The balance of Plant in Service for regulatory purposes matches the property, plant and equipment balance for accounting purposes at the end of 2018.

Note that Creative Energy uses a loaded rate when employees directly charge time to capital. This rate includes O&M costs that are directly related to the employee performing their tasks such as IT, dues and memberships, training and cell phone costs. Actual O&M costs would be higher if these costs were not included in the loaded rate.

7.2 Please explain why there are no O&M expenses capitalized in 2015 and 2018 Actual.

Please see the response to BCUC IR 7.1.

7.3 Please explain why there are no O&M expenses expected to be capitalized in 2019 and 2020 test years.

RESPONSE:

Please see the response to BCUC IR 7.1.

8.0 Reference: CORE STEAM REVENUE REQUIREMENTS
Exhibit B-1, Section 3.2.3.2, p. 25; Exhibit B-1-1, Appendix 1, p. 4
Wages and Benefits – Account #500 – Steam Production Supervision and Labour

On page 4 of Appendix 1 to the Evidentiary Update, Creative Energy provided Table 17 showing a detailed breakdown of Account #500 – Steam Production Supervision and Labour costs, including base wages, overtime and benefit costs, for 2015 to 2018 Actual, 2018 Approved, and 2019 and 2020 Test Year.

On page 25 of the Application, Creative Energy states "Compared to 2018 Approved levels, base wages for 2020 Test Year are planned to increase approximately 3.7 percent, compared with union-approved annual wage increase of 1.8 percent per year over the two year [*sic*] 2019-2020 test period."

On page 25 of the Application, Creative Energy states:

> 2018 Approved levels did not record the cost of overtime, which is necessary periodically to maintain efficient operation of the plant, for example when operations staff work additional hours to cover for another employee that is away sick. The average actual cost for overtime between 2015 and 2018 was $37,000 and was as high as $67,000 in 2018. Overtime is estimated at $54,000 for the 2020 Test Year.

8.1 Please explain why the 2019 Test Year base wages ($1,226,794) increased by approximately 9percent compared to 2018 Actual base wages ($1,130,144), considering that the annual union-approved wage increase was 1.8 percent for 2019.

RESPONSE:

In dollars, the increase is $96,650. The wage increases of 1.8% represents $20,343 of the increase. A

number of factors contributed to 2019 actuals being more than 1.8% higher. This includes the following: there were job vacancies for part of 2018, most significantly the Chief Engineer position, that were not experienced in 2019; overtime was correspondingly higher in 2018 than in 2019; and there were more new employees hired in 2018 than 2019. For new plant employees, there is a probationary period where they earn less than full salary.

Note that this cost should be viewed in combination with Distribution wages. During 2018, the plant team and distribution team shared employees that were qualified to work for both groups.

8.1.1 Please provide the percentages of union and non-union employees within Steam Production Supervision and Labour.

RESPONSE:

There are twelve employees included in Steam Production, Supervision and Labour. In 2018, all were union employees. One employee left the union and became part of the management team in Q4 2019, but their full costs will continue to be included in Steam Production Supervision and Labour in 2019 and 2020.

8.2 Please explain why 2018 Actual overtime cost for Steam Production Supervision and Labour was approximately 81 percent higher than the average cost for overtime between 2015 and 2018 ($37,000).

RESPONSE:

Overtime in the plant typically relates to missed shifts due to sick days. The number of sick days in 2018 was higher than average, in part due to one employee who had two periods of sick leave before going on short term disability in 2018.

8.3 Please provide supporting calculations for the 2020 Test Year forecast cost for overtime ($53,692) shown in Table 17.

RESPONSE:

Overtime for 2020 was based primarily on 2017 and 2018 actuals with a higher weight applied to 2018 due to the higher overtime cost incurred during that period related to the impact of sick days taken.

Creative Energy notes that there are essentially no supporting calculations to predict overtime expense; the estimated overtime expense was based on a qualitative judgement as between the cost in 2017 and the very high cost in 2018.

Creative Energy considers that 2020 is still a reasonable forecast at this time considering the risk of sick days are volatile and outside of Creative Energy's control.

8.3.1 Please explain why the cost for overtime in the 2020 Test Year is expected to be approximately 46 percent more than the average cost for overtime between 2015 and 2015 ($37,000) and approximately 70 percent higher than 2019 Test Year.

RESPONSE:

Overtime relates almost entirely to sick days. Please refer to the responses to BCUC IRs 8.2 and 8.3.

8.4 Please explain statement on page 25 of the Application with respect to why "2018 Approved levels did not record the cost of overtime."

RESPONSE:

The 2018-2022 RRA did not include overtime costs for the plant team. Current Creative Energy staff cannot explain why overtime was not included or missed in that application given that overtime has historically been a cost to Creative Energy and continues to be.

8.5 Please explain why the cost for benefits in the 2019 Test Year ($142,987) is approximately 37 percent higher than 2018 Actual ($103,999).

RESPONSE:

A new Employer Health Tax was added in 2019 that did not exist in 2018. The impact of this was $23,183. MSP still existed for all of 2019. In addition, $5,317 related in increases in CPP and EI, $5,613 related to WCB and $4,676 related to higher Extended Health premiums in 2019.

9.0 Reference: CORE STEAM REVENUE REQUIREMENTS
Exhibit B-1, Section 3.2.3.3, pp. 25–26; Exhibit B-1-1, Appendix 1, p. 4
Wages and Benefits – Account #870 – Distribution Supervision and Labour

On page 4 of Appendix 1 to the Evidentiary Update, Creative Energy provided Table 19 showing a detailed breakdown of Account #870 – Distribution Supervision and Labour costs, including base wages, overtime and benefit costs, for 2015 to 2018 Actual, 2018 Approved, and 2019 and 2020 Test Year.

On pages 25 to 26 of the Application, Creative Energy states, "Compared to 2018 Approved, base wages for the 2020 Test Year are planned to increase approximately 10 percent. Approximately 3.6 percent of this increase relates to union approved annual wage increase in absolute terms…"

9.1 Please explain why base wages and costs for overtime increased from 2017 Actual to 2018 Actual (i.e. from $404,526 to $447,044, and $6,854 to $20,310, respectively).

RESPONSE:

Base wages increased from 2017 Actual to 2018 Actual primarily due to:

1. **The implementation of the $1 premium for red seal tickets, an impact of $10,000 in 2018. (The Red Seal Program is recognized as the interprovincial standard of excellence in the skilled trades. Through the program, tradespersons are able to obtain a Red Seal endorsement on their provincial/territorial certificates by successfully completing an interprovincial Red Seal examination); and**

2. **Wage increases outside of union increases due to employee promotions, an impact of $22,000 in 2018.**

The remainder of the increase was due to the union rate increase.

Distribution team overtime increased in 2018 related to unscheduled distribution maintenance and the assistance that the Distribution team provided the Plant team for the coverage required due to the higher number of sick days in the plant, as described in the response to BCUC IR 8.3.

9.2 Please provide the percentages of union and non-union employees within Distribution Production Supervision and Labour.

RESPONSE:

All employees within Distribution Production Supervision and Labour are members of the union.

10.0 Reference: CORE STEAM REVENUE REQUIREMENTS
Exhibit B-1, Section 3.2.4.1, p. 29; Exhibit B-1-1, p. 4
Water Expenses

On page 29 of the Application, Creative Energy states:

> For the purpose of estimating overall 2020 water costs, historical data from 2017-2019 is used to project the volume of water required for each M# of steam sold. Water consumption has been projected using the average ratio of pounds of steam sold for every pound of water consumed. The projected volume of water was multiplied by the 2019 City of Vancouver water rate plus [an assumed] 6.5% rate increase.

10.1 Please further elaborate on the choice to use three years of historical data as the basis for the projected volume of water. Did Creative Energy consider using a longer historical period such as five or ten years? Why or why not?

RESPONSE:

Creative Energy is of the view that 2019 actuals are most relevant for forecasting future water costs, in particular due to water use efficiency improvements that have been experienced since 2018. Creative Energy notes also that data on water volumes for more than 3 years has not been tracked in our system outside of the individual invoicing records and this data is therefore not readily available for analysis.

10.1.1 Please confirm, or explain otherwise, that the historic ratio of pounds of steam sold for every pound of water consumed used to derive the 2020 forecast was <u>not</u> updated in the Evidentiary Update for the most recently available data (i.e. 2020 forecast water expense is the same before and after the Evidentiary Update).

RESPONSE:

Confirmed. The most recently available data is the October-January water invoice which was not received until March and could not be used for the Evidentiary Update. In addition, the City of Vancouver informed customers that the high season (with higher rates) has been extended by 45 days; the high season is now May 1 – October 15. We have recalculated the estimated cost of water based on actual 2020 rates and the new high season time frame in the response to BCUC IR 10.1.1.1.

10.1.1.1 If confirmed, please provide the incremental impact, if any, to the revenue requirements and the steam rate, if all the most recently available data from 2019 were used in the 2020 forecast water expense calculation.

RESPONSE:

Using 2019 actual load and water bills to forecast the units of water for 2020 and updating the projection for actual 2020 rates and now the change in the City's peak period definition (as noted in the response to BCUC IR 10.1.1), a recalculation of water costs is shown in the table below.

The difference from the water costs projected in the Evidentiary Update ($743,622) is an additional increase of $35,199 ($778,821 less $743,622), which is in addition to the projected increase in water costs of $22,344 for the reasons noted on page 4 of the Evidentiary Update.

That is, the total increase in projected water costs over the amount currently reflected in the Application for approval as part of the 2020 RRA equals $57,543, or approximately an additional 0.7% increase in the average steam rate (or an ~4.9 % increase compared to the 2019 interim approved rate). The magnitude of these changes further illustrates the risk in relation to this unpredictable item outside of Creative Energy's control.

For these reasons, Creative Energy now requests approval of a deferral account to track the difference between actual total annual water costs versus forecast total annual water costs (the Water Cost Deferral Account or WCDA).

Water rates are set by the City of Vancouver and are inherently uncertain for the purposes of forecasting Creative Energy revenue requirements on a test year plan basis. The water rates applicable to Creative Energy for a test year plan period are not finalized until some point in the actual year of concern, which is a further risk that Creative Energy cannot control for under either a single period or multi-period revenue requirements application.

Creative Energy proposes that the balance in the WCDA be amortized over a one-year period on an ongoing basis at a carrying cost equal to Creative Energy's short-term debt rate. Creative Energy proposes that the net balance in the WCDA, as between actual and forecast amounts from the prior year can be recorded for credit or recovery through the net amount of all outstanding balances for Creative Energy's deferral accounts that are recovered through the DARR.

Month	Load	L Per M#	Litres	Units of Water	Rate	Cost
January	163,030	520	84,724,286	29,921	$ 3.428	$ 102,569
February	139,898	510	71,379,013	25,208	$ 3.428	$ 86,413
March	129,547	510	66,097,603	23,343	$ 3.428	$ 80,019
April	98,566	510	50,290,568	17,760	$ 3.428	$ 60,883
May	70,212	510	35,823,354	12,651	$ 4.297	$ 54,363
June	50,960	607	30,955,421	10,932	$ 4.297	$ 46,975
July	42,023	607	25,526,876	9,015	$ 4.297	$ 38,737
August	39,380	607	23,921,150	8,448	$ 4.297	$ 36,301
September	48,710	607	29,588,573	10,449	$ 4.297	$ 44,901
October (half)	40,980	520	21,296,498	7,521	$ 4.297	$ 32,318
October (half)	40,980	520	21,296,498	7,521	$ 3.428	$ 25,782
November	124,562	520	64,732,650	22,861	$ 3.428	$ 78,367
December	151,787	520	78,881,085	27,857	$ 3.428	$ 95,495
	1,140,634		604,513,576	213,488		$ 783,124
Meter Charge						$ 1,731
Sewer Meter 4.2%						$ 32,891
Gross Water Costs						$ 817,746
Discount 4.76%						$ (38,925)
						$ 778,821

10.2 Please complete the following table:

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Test Year	2020 Test Year
Steam load (M#)						
Water load (Units)						
Ratio of Steam Load to Water Load						

RESPONSE:

As discussed in the response to BCUC IR 10.1, historical data other than actual billings in 2019 is not used in the forecasting of water costs.

Please see below for a record of the last four bills which include October 2018 – January 2020 and the ratio of M#'s to units of water sold. As explained in the response to BCUC IR 10.1, historical data is not readily available.

Historical Invoices	Units of Water	L of Water (2831.6 L per unit)	Actual Load (M#) adjusted for NEFC Meter Issue	L Per M#
Oct 1 2018 - Jan 31, 201	89,678	253,931,772	483,406	525
Feb 1 - May 31, 2019	85,806	242,967,943	467,505	520
June 1-Sept 30, 2019	38,371	108,652,555	179,080	607
Oct 1 2019 - Jan 31, 202	95,220	269,624,952	522,863	516

NEFC load was normalized for October 2018 – December 2019 based on the imputed NEFC load using actual hot water consumption (MWh) in order to ensure that this record can be used to forecast costs in 2020.

On page 4 of the Evidentiary Update, Creative Energy states that the actual City of Vancouver water rate increase for 2020 equals 9.7 percent, compared to the forecast water rate increase of 6.5 percent included in the Application. Creative Energy states:

> The incremental impact is $22,344 and the net effect of this change together with the Municipal Access Fee change would be to increase the required steam rate increase to 4.5%...[However], Creative Energy does not at this time seek to amend its proposal for a 4.2 percent increase in 2020 rates and therefore the impact of the water rate increase is not reflected in the Table 2 Update at this time.

10.3 Please explain why Creative Energy does not seek to amend its proposal for a 4.2 percent increase in 2020 rates to 4.5 percent.

RESPONSE:

Creative Energy initially considered that it was not necessary, at the time of submitting the Evidentiary Update, to specify an amendment to its application for 2020 rates, expecting ultimately

that the BCUC in its final decision on this Application could address the recovery or refund as the case may be of any change between final and interim 2020 rates. That is, the Commission's decision into the specific line-items in Creative Energy's RRA could necessarily incorporate higher actual 2020 costs related to water rates into a final determination and approval of the required percentage increase in steam rates.

However, further to the proposed WCDA set out in the response to BCUC IR 10.1.1.1., Creative Energy now seeks an amendment to the mechanism for recovering forecast versus actual water costs. Creative Energy has set out in the Evidentiary Update that it seeks approval of its 2020 Core Steam revenue requirement, comprised of $9,093,363 to be recovered through its steam tariff at rates determined on the basis of an approved load forecast, and through the DARR, as proposed and approved on an interim basis to recover $331,097. Under the proposed WCDA and recovery mechanism, beginning in 2021 the DARR would allow credit or recovery as necessary between actual annual water costs and the forecast of annual water costs currently factored into the proposed 4.2 percent increase in 2020 steam rates.

10.4 Please confirm whether Creative Energy intends to recover the difference between the required steam rate increase of 4.5 percent and the requested steam rate increase of 4.2 percent in a future RRA or whether this difference is treated as a shareholder cost.

RESPONSE:

Please refer to the response to BCUC IR 10.3.

10.5 Please provide the difference in the required steam rate increase of 4.5 percent and the requested steam rate increase of 4.2 percent in dollars.

RESPONSE:

Please see the responses to BCUC IRs 10.1.1.1 and 10.3.

11.0 Reference: CORE STEAM REVENUE REQUIREMENTS
Exhibit B-1, Section 3.2.4.2, p. 29; Exhibit B-1-1, p. 2
Water Treatment Expenses

On page 29 of the Application, Creative Energy states:

> Water treatment costs in 2017 and 2018 were significantly higher than the actual cost from 2015 and 2016 and the approved costs. While this was partially due to load, a Softener System Upgrade capital project was implemented during 2018 that resulted in more accurate metering of water and salt brine, improving efficiencies for the regeneration cycle.

On page 29 of the Application, Creative Energy also states:

> It is estimated that with the efficiency improvements noted above that water treatment costs for the 2020 Test Year will be more in line with 2015 and 2016 actuals and the 2018 Approved cost.

On page 2 of the Evidentiary Update, Creative Energy states, "Reported Water-related and Electricity

Expenses are $43,121, lower due to lower than projected water treatment costs."

11.1 Please specify when (i.e. which month) the Softener System Upgrade capital project was implemented during 2018.

RESPONSE:

The project was started in May 2017. Upgraded control units and resin were purchased in 2017 and held in the plant for installation. Work on the upgrade was continued in June 2018 and continued through October 2019 due to various issues.

Work on the upgrade was continued in June 2018 given that it was not complete ahead of Fall and Winter heating load increases. The project was continued in June 2018, after the Winter and Spring load in the Plant had been greatly reduced.

Work continued into October 2019 for the following reasons:

- **A failed resin trap was identified during the winter load of 2018/19, identifying the need for Softener 2 to be opened back up again, to have the resin removed, nozzles replaced, and the resin trap replaced. When the vessel was opened, it was found that less than 10% of the new resin had remained in the vessel and had gone into the feedwater system. This resulted in a significant amount of maintenance work in the plant to remove resin from areas where it was blocking feedwater strainers and other related instrumentation. It was found that several nozzles had been cracked or displaced from their normal positions, resulting in resin leaving the vessel.**
- **Further inspection of Softeners 1 and 3 identified another resin trap that needed replacing due to incorrect original installation; and**
- **Further work on fine tuning the newly installed control system in 2018 identified the need to replace the 3 main water isolation valves due to their leakage, as well as several control valves for the sequencing of the regeneration cycle needed to be rebuilt.**

These items occurred in succession and limitations on the ability to completely repair them in a timely manner were due largely to overall load on the Boiler plant as fall, winter and spring loads make this work more challenging to complete.

11.2 Please further elaborate on the issues in 2017 and 2018 that resulted in higher-than-normal water treatment expenses and how that was or was not impacted by the Softener System Upgrade capital project in 2018.

RESPONSE:

Please refer to the response to BCUC IR 11.1

11.3 Please explain to what extent the decline in water treatment expenses in 2019 are due to the Softener System Upgrade capital project or to other factors.

RESPONSE:

It is not possible to specifically measure the impact of the decline in water treatment expenses due to the Softener System Upgrade. Overall reduced salt usage due to longer softener resin life has led to lower costs overall. However, other factors such as improved operational control have also led to savings.

Creative Energy also notes that the original estimate for 2019 was based on where costs were tracking up to the time of the Application. Actual costs were ultimately lower as some of the purchases remained in inventory at year end.

11.4 Please provide the methodology used to forecast the water treatment costs for the 2020 Test Year. How has Creative Energy treated the higher-than-average expenses in 2017 and 2018 and the expected efficiency improvements in its forecast methodology?

RESPONSE:

The estimate was based on the 5-year average ($143,438) adjusted down by about $10,000 to recognize possible efficiency improvements related to the softener project and improved operations control (noting as above that those benefits cannot be specifically quantified). Future actual results may make the impact of efficiency improvements more evident, and the average calculation used to forecast costs in the future will then be adjusted accordingly to reflect any trends as need be.

11.4.1 Please confirm whether the updated, 2019 Actual water treatment expenses are used to derive the 2020 Test Year forecast. Why or why not?

RESPONSE:

Please refer to the response to BCUC IR 11.4.

11.4.1.1 If not confirmed, please provide the incremental impact, if any, to the revenue requirements and the steam rate, if the most recently available data from 2019 is used in the forecast calculation.

RESPONSE:

Please refer to the response to BCUC IR 11.4.

12.0 Reference: CORE STEAM REVENUE REQUIREMENTS
Exhibit B-1, Section 3.2.4.3, p. 30; Exhibit B-1-1, Appendix 1, p. 5
Electricity Expenses

On page 30 of the Application, Creative Energy states:

> Creative Energy takes electricity service from BC Hydro under Large General Service Rate Schedule 1611. Electricity costs for the 2020 Test Year factor in the requested rate increases in BC Hydro's 2019-2020 RRA of 6.85 percent in 2019 and 0.72 percent in 2020, both effective April 1st per BC Hydro's fiscal year. The estimate of 2020 electricity costs uses an estimate of historical peak demand by month to forecast demand charges and an estimate of the ratio of electricity consumption to steam production to forecast energy charges.

In Exhibit B-11 of the BC Hydro Fiscal 2020 to 2021 Revenue Requirements Application proceeding, BC Hydro provided an Evidentiary Update revising the 0.72 percent rate increase for F2021 to a decrease of

0.99 percent.[2]

12.1 Please explain, in Creative Energy's view, whether it would be appropriate to revise its electricity expense forecast based on the latest evidentiary update from BC Hydro's Fiscal 2020 to 2021 Revenue Requirements Application.

RESPONSE:

Creative Energy notes that the BCUC pursuant to Order G-32-20 approved for BC Hydro a rate decrease of 1.01 percent effective April 1, 2020 on an interim basis. The BC Hydro rates will remain interim and subject to further adjustment until the BCUC issues its final decision into BC Hydro's F20-F21 RRA, possibly in the Fall. It may be appropriate to revise the forecast electricity expense based on the rates set by BCUC Order G-32-20, though those rates are interim and subject to further change. It may be appropriate otherwise, or also, to establish a deferral account to record any cost variance associated with a difference between forecast and actual electricity rates for a given approved load forecast.

12.2 Please elaborate on the methodology used for forecasting electricity expenses. Please include in the response the time period used to calculate the historical peak demand and the ratio of electricity consumption to steam production.

RESPONSE:

The estimate was based on invoices from 2018 and 2019 that were available at the time of the Application with reference to the ratio of M# of steam sold to kWh of electricity by month and peak load by month. Based on these drivers, rates from the most recent bill were used for the following: Basic Charge per day, Energy charges per kWh, Demand charges per kW, transformer discount and primary potential discount. The average ratio used for estimating electricity consumption to steam consumption was 0.87 kWh per M#.

On page 5 of Appendix 1 of the Evidentiary Update, Creative Energy provides the following table showing water and electricity expenses for 2015 to 2018 Actual, 2018 Approved, and 2019 and 2020 Test Year:

Table 23 Update: Water and Electricity Related Expenses – Account 502 Partial and Account 874 – Summary

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2018 Approved	2019 Test Year	2020 Test Year
502 Steam Expenses - Partial							
Water	500,997	580,806	617,733	661,905	502,200	696,145	743,622
Electricity	115,610	94,934	78,068	77,380	118,018	102,640	93,624

12.3 Please explain what factors contributed to the decline in Actual electricity expenses from 2015 to 2018.

RESPONSE:

Although Creative Energy has not specifically differentiated the factors that contributed to the observed decline in actual electricity expenses between 2015 and 2018, it is likely that the overall decline is explained in part by warmer than average weather in 2016 (i.e. lower load) and a significant change in the Large General Service rate design that was approved by Order G-5-17 effective April 1,

[2] Retrieved from: https://www.bcuc.com/Documents/Proceedings/2019/DOC_55184_B-11-BCH-Evidentiary-Update-Public.pdf

2017 in the matter of BC Hydro's 2015 Rate Design Application. Creative Energy has attached no predictive value to actual water and electricity -related expenses that pre-date the change in rate design in 2017, outside of the impact of energy load and peak demand on forecast electricity costs.

12.4 Please explain what factors contributed to the increase in Actual electricity expenses from $77,380 to $103,396 between 2018 Actual to 2019 Test Year.

RESPONSE:

The increase is likely mainly explained by the increase in load in 2019 compared to 2018, outside of the changes in the underlying electricity rates. Please refer also to the responses to BCUC IRs 12.1-12.3.

12.5 Given that forecast electricity expenses are based on the "ratio of electricity consumption to steam production" and that water expenses are forecast to increase in the 2020 Test Year, please explain why electricity expense is expected to decrease between 2019 and 2020 Test Years. What factors are expected to change between 2019 and 2020?

RESPONSE:

While electricity generally moves directionally with load, it is still a challenge to obtain a strong estimate for electricity expense by using M#'s of steam sold as a predictor. Creative Energy is billed by BC Hydro based on kWh energy consumption and peak load. Electricity expense was originally estimated using data from both 2018 and 2019 for kWh consumption and peak load. Peak load in 2018 was lower than 2019, which is why the estimate for 2020 is lower than 2019 despite a higher load forecast and a higher water cost forecast.

12.5.1 Please confirm, or otherwise explain, whether the updated, Actual 2019 electricity expenses are used to derive the 2020 Test Year forecast. Why or why not?

RESPONSE:

Actual 2019 expenses were only used in the estimate up to August 2019.

12.5.1.1 If not confirmed, please provide the incremental impact, if any, to the revenue requirements and the steam rate, if the most recently available data from 2019 is used in the forecast calculation.

RESPONSE:

No change is necessary recognizing that the estimated 2020 cost is less than the 5-year average. Please refer to the response to BCUC IR 12.1, which suggests that a deferral account may be an appropriate means to record any cost variance associated with a difference between forecast and actual electricity rates and costs for a given approved load forecast.

13.0 Reference: CORE STEAM REVENUE REQUIREMENTS
Exhibit B-1-1, Appendix 1, p. 5; Exhibit B-1, Section 3.2.5, p. 30
Maintenance Expenses

On page 5 of Appendix 1 to the Evidentiary Update, Creative Energy provided Tables 23 and 25 showing that Account #502 – Steam Expenses is split between "Water and Electricity Related Expenses" and "Maintenance and related functional operation."

13.1 Please explain how Account #502 – Steam Expenses was split between "Water and Electricity Expenses" shown in Table 23 and "Maintenance and related functional operation" expenses in Table 25.

RESPONSE:

The split of steam expenses is based on an assessment of the steam expenses that are externally driven as related to water rates, water treatment and electricity costs versus steam plant expenses that are recorded to Account #502 but are generally under management control. The costs in the latter category include: Plant Maintenance and Supplies, Permits and Inspections, Safety Supplies and Training and Uniforms.

On page 5 of Appendix 1 to the Evidentiary Update, Creative Energy provided the following breakdown of Maintenance and relation functional operation costs for 2015 to 2018 Actual, 2018 Approved, and 2019 and 2020 Test Year:

Table 25 Update: Maintenance and related functional operation – Multiple Accounts – Detailed Summary

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2018 Approved	2019 Test Year	2020 Test Year
502 Steam Expenses – Maintenance & related	153,371	94,582	225,735	180,529	229,321	194,488	140,320
506 Structures and Improvements	3,576	1,548	8,230	37,129	9,573	86,693	78,696
880 Other Distribution Operation	-	-	-	-	15,582	-	-
933 Transportation	14,102	11,198	13,612	13,191	24,951	23,481	20,840
887 Mains and Services	35,838	44,716	52,965	42,286	68,233	72,268	51,880
889 Meters & House Regulators	106,675	160,888	90,809	112,863	116,403	126,777	187,000
932 Maintenance of General Plant	15,814	16,873	22,980	71,747	23,932	22171	20,372
Total	329,376	329,805	414,331	457,744	487,994	525,878	499,108

On page 30 of the Application, Creative Energy states, "[t]he unusual recorded percentage variance in account 506 compared to 2018 Approved reflects a change in the coding of costs to this category in recent years".

13.2 Please explain the change in coding of costs to Account #506 – Structures and Improvements. In which account were these costs categorized for 2018 Approved? Are the offsetting variances contained within overall maintenance costs? If not, where do these variances reside?

RESPONSE:

Accounts 502 and 506 both relate to the Steam Plant. Creative Energy's internal budgeting process looks at these categories in combination and spends in accordance with priorities as they develop throughout the year. From an internal accounting perspective, the difference between the nature of expense coded to an account grouped to 502 (maintenance) or 506 (improvement) can be difficult to distinguish. The budgets and actuals for these accounts should be looked at in combination.

On page 30 of the Application, Creative Energy states, "Forecast 2020 maintenance costs exceed 2018 Approved amounts by 2 percent… The evident longer-term trend of increasing maintenance costs from 2015 through 2020 forecast relates to a requirement for more inspections of ageing equipment and more expensive work to maintain that equipment, noting that the amount of equipment to be maintained is generally stable."

13.3 Please provide the percentage increases in maintenance costs in each year from 2015 Actual through 2018 Actual, and 2019 Test Year compared to 2018 Actual.

RESPONSE:

Please refer to the following table.

	2015	2016	2017	2018	2019	2020
Total	329,376	329,805	414,331	457,744	525,878	499,108
Increase		0.1%	25.6%	10.5%	14.9%	-5.1%

13.3.1 Please explain why Creative Energy considers that 2020 Test Year maintenance costs, which are 2 percent higher than 2018 Approved amounts, is reasonable, considering the percentage increases provided in the response above.

RESPONSE:

The 2020 budget looked at the average of actual costs from both 2018 and 2019 ($491,811), plus an adjustment for inflation, which gives a higher weight to the more recent actual maintenance costs, which are more reflective of ongoing requirements.

These numbers are consistent with the 2020 budget that operations management must follow. Actuals are tracked on a monthly basis and reviewed with operations management. Each month, finance and operations management reforecast and assess required spending to ensure that costs are appropriately prioritized to meet budget.

13.4 Please explain why 2020 Test Year forecast maintenance expenses should be less than 2019 Test Year expenses, considering the longer-term trend.

RESPONSE:

Please refer to the response to BCUC 13.3.1.

14.0 Reference: CORE STEAM REVENUE REQUIREMENTS
Exhibit B-1-1, Appendix 1, p. 5; Exhibit B-1, Section 3.2.6, pp. 31–32
Special Services Expenses

On page 5 of Appendix 1 to the Evidentiary Update, Creative Energy provided the following breakdown of Special Services costs for 2015 to 2018 Actual, 2018 Approved, and 2019 and 2020 Test Year:

Table 27 Update: Special Services – Account 923 – Summary

923 Special Services	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2018 Approved	2019 Test Year	2020 Test Year
Audit Fees	51,200	70,975	28,596	47,203	28,590	57,234	44,578
Legal Fees	18,284	20,242	7,875	18,654	17,869	5,586	13,171
Outside Services	129,241	115,448	52,439	101,325	51,205	112,067	105,466
Regulatory	47,397	179,552	21,684	343,309	135,651	312,991	150,000
Total	246,122	386,217	110,595	510,491	233,315	487,878	313,215

On page 31 of the Application, Creative Energy states it "expects that 2020 Regulatory expenses ought to be closer in range to 2018 Approved levels and therefore it budgets $150,000 for the 2020 test period…"

14.1 In the same format as Table 29 on page 31 of the Application, please provide a breakdown of the 2020 Test Year forecast regulatory expenses.

RESPONSE:

As discussed in the Application in reference to regulatory expenses, Creative Energy reiterates that these costs are difficult to forecast, and it is for this reason that the existing deferral account is appropriate to record variances in such costs. Accordingly, Creative Energy will apply differences between forecast and actual total 2020 regulatory expenses to the Third-Party Regulatory Costs Deferral Account for the purpose of rate setting on go-forward basis.

The following table applies estimates by category and anticipated proceeding in the requested format, acknowledging the underlying uncertainty.

	2020 Projected
BCUC	
Annual Fee (paid quarterly)	50,000
Beatty CPCN Commission & Contractor Fees	25,000
2019-2020 RRA Commission & Contractor Fees	25,000
2019-2020 RRA PACA award	25,000
Regulatory Legal Support	
2019-2020 RRA	25,000
Total Forecast Regulatory in the Application	150,000
Beatty CPCN PACA Award	34,551

Further to the introductory comment to this response, there is uncertainty in these costs, even as between the time that the Application was filed, noting for example that:

- **Creative Energy now expects to pay a PACA award in the amount of $34,551 in 2020 as applied for by an intervenor in the Beatty CPCN proceeding. Technically that amount should be recorded to 2019 covering the period of work. However, based on the dollar value not being significant for our audit and considering that our books are now closed for 2019, the amount will be entered into 2020, thereby increasing the regulatory cost estimate from the $150,000; and**

- **The broad estimate of $150,000 also did not contemplate costs associated with the external consultant and legal support for, and Commission and intervener review of, Creative Energy's proposal for recovery of costs recorded to the Fuel Switch Study and LTRP Deferral Account, directed by the Commission to be filed on February 21, 2020 and now included for review as part of the 2019-2020 RRA proceeding.**

On page 32 of the Application, Creative Energy states, "The average actual costs form 2015 through 2018 for Outside Services has been approximately $100,000 and actual average amounts are considered representative of ongoing company priorities."

14.2 Please explain why Outside Services in 2017 Actual of $52,439 were lower than the actual average cost of 2015 through 2018 of approximately $100,000.

RESPONSE:

The nature of outside services varies from year to year, but typically relates to advisory services and consulting services for business development opportunities and other small projects. From 2017-2019, these costs primarily related to initiatives related to the LTRP and ongoing efforts to enable low-carbon energy project development.

On page 32 of the Application, Creative Energy states that actual Audit Fees from 2015 through 2018 averaged $49,000 during that period.

14.3 Please explain why Audit Fees for 2017 Actual of $28,596 were less than the five-year average of Actual audit fees from 2015 though 2018 of $49,000.

RESPONSE:

Audit fees are accrued through the year. Billings for the year are not finalized until the year after. The amount accrued in 2016 was too high. The accrual reversed in 2017 reduced costs for 2017. The average for 2016 and 2017 was $49,786, which is in line with other years.

15.0 Reference: CORE STEAM REVENUE REQUIREMENTS
Exhibit B-1-1, Appendix 1, p. 6
Other General & Administrative and Sales Expense

On page 6 of Appendix 1 to the Evidentiary Update, Creative Energy provided the following breakdown of Other General & Administrative costs for 2015 to 2018 Actual, 2018 Approved, and 2019 and 2020 Test Year:

Table 30 Update: Other General & Administrative – Multiple Accounts - Summary

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2018 Approved	2019 Projected	2020 Test Year
915 Directors Fees	71,135	49,268	24,150	28,200	40,023		41,686
921 Office Supplies & Expenses	110,831	110,167	114,006	106,356	92,776	113,100	104,801
922 Admin & General Expenses	18,874	6,011	4,697	25,493	10,693	5,115	7,303
924 Insurance	102,466	109,466	103,106	107,102	103,877	122,971	138,740
925 Injuries & Damages - WCB	7,078	6,959	4,527	6,622	5,907	7,206	6,520
Total	310,384	281,871	250,486	273,773	253,276	248,392	299,050

15.1 Please explain why Directors Fees are nil for the 2019 Test Year.

RESPONSE:

There were no external Directors in 2019 that charged fees.

15.2 Please explain how the 2020 Test Year forecast for Directors Fees ($41,686) was developed.

RESPONSE:

Directors fees were estimated to be approximately equal to the 2018 approved cost of $40,023. Creative Energy anticipates appointing external directors during 2020.

15.3 Please explain how the 2020 Test Year forecast for Admin & General Expenses ($7,303) was developed. Why were 2018 Actual costs of $25,493 higher?

RESPONSE:

This category consists of a variety of items such as team building events, the company Christmas breakfast, summer BBQ, office snacks, employee accommodation and food-related travel expenses while employees attend conferences. A portion of these costs are now included in employee benefits in 2019 and 2020.

16.0 Reference: CORE STEAM REVENUE REQUIREMENTS
Exhibit B-1, Section 3.3, p. 34; Exhibit B-1-1, Evidentiary Update Schedules for RRA Filing, Core Schedule 17
Municipal Taxes (City of Vancouver Municipal Access Fee)

On page 34 of the Application, Creative Energy states:

> In exchange for the rights under the MAA, the Company pays to the City an annual fee equal to 1.25 percent of Tariff Revenues plus a flat fee that the City escalates at 2 percent for each of 2019 and 2020.

Section 3.2 License Fees, of the Municipal Access Agreement (MAA) dated September 1, 1999[3] states:

> *["On April 15, 2000 and April 15 of each and every following year of this Agreement the Company will pay the total of the following amounts:*
>
> *(i) 1.25% of the amount obtained by deduction the Fuel Adjustment Costs from the Total System Portion of Gross Revenue for the immediately preceding calendar year, plus*
>
> *(ii) $100,000 adjusted (on a cumulative basis) in each year (commencing with an adjustment to the first such payment on April 15, 200) in proportion to any and all changes made during the prior calendar year to the Company's prices net of fuel adjustment recoveries for the sale of heat or cold. "]*[8]

Creative Energy provides the calculation of the City of Vancouver Municipal Access Fee in the Financial Schedules attached to the Evidentiary Update (Core Schedule 17). The financial schedule includes the following note with respect to Line 1 of the calculation:

> Note: Revenue Requirement +/- Rate Rider + $.41 per MBTU adjustment - internal

[3] Creative Energy 2016-2017 Revenue Requirements and Rate Design for Northeast False Creek Hot Water Service Application, Exhibit B-1A, p. 35

revenue from NEFC

16.1 Please confirm whether the 1.25 percent tax rate should be applied to the previous years' annual steam revenues as stated in the Section 3.2(i) of the MAA or to the steam revenues in the current year as shown in Core Schedule 17.

RESPONSE:

Municipal Access Fees are paid in April of the subsequent year once the numbers have been audited. Costs are accrued throughout the year based on the formula described in the agreement. The reference to "previous year's" as stated in Section 3.2 (i) is actually referring to the current year. As such, the cost estimates for 2019 and 2020 costs should be based on the steam revenue forecast for those years.

16.2 Please explain how the note (and Excel formulas) with respect to Line 1 of the City of Vancouver Municipal Access Fee calculation in Core Schedule 17 reflects the calculation of the fee as outlined in Section 3.2(i) of the MAA (i.e please explain the individual components of the calculation).

RESPONSE:

The calculation described in Section 3.2 is no longer relevant. An amendment was agreed to for the 2017 and 2018 fiscal years. Please refer to Attachment 16.2-A. Please also refer to Attachment 16.2-B, which is the amendment letter describing the new methodology and that includes the fixed fee escalating at 2% per year and a $0.41 per MBTU adjustment.

16.3 Please explain the methodology used to calculate the 2 percent escalation of the Flat Fee for each of 2019 and 2020.

RESPONSE:

The 2018 fixed fee was increased by 2% for 2019. The 2019 fixed fee was increased by 2% for 2020. Please refer to the amendment letter attached to the response to BCUC IR 16.2.

17.0 Reference: CORE STEAM REVENUE REQUIREMENTS
Exhibit B-1, Section 3.4, p. 35; Exhibit B-1-1, p. 2; Appendix 1, p. 2
Property Taxes

On page 35 of the Application, Creative Energy states that "[t]he 2019 Test Year is based on the actual assessment. As the 2020 assessment is not yet available, the 2020 Test Year estimates the cost by increasing the assessed value of land by 7.6 percent and the additional property tax for 701 Expo Blvd. by 7.6 percent…"

On page 2 of the Evidentiary Update, Creative Energy states that 2019 Test Year property taxes have been updated to reflect that "Reported Property Taxes are $1,926 higher."

17.1 Please explain why 2019 Test Year property taxes are $1,926 higher in the Evidentiary Update, considering that the Application states that 2019 Test Year property taxes are "based on the actual assessment."

RESPONSE:

In the evidentiary update, Creative Energy used the actual expense in the general ledger (GL). The number used in the Application was based on a calculation (Schedule 16) which uses actual mill rates and the assessed land and building values. The difference from the GL is not considered significant but has been adjusted to the GL value to be consistent with adjustments made in the Evidentiary Update for other O&M expense items.

17.2 Please provide the rationale for using an increase of 7.6 percent for the assessed land value and property tax rate, respectively, for forecasting 2020 Test Year property taxes.

RESPONSE:

The mill rates are not finalized or published until May so there is still uncertainty until then. The interim billing for 2020, received in December 2019, was the best evidence Creative had at the time for increasing property tax expense. The 2020 interim bill was approximately 7.6% higher than the 2019 interim bill.

17.2.1 Please explain why the forecast for 2020 Test Year property taxes is the same before and after Creative Energy's Evidentiary Update, given that 2019 Test Year property taxes were increased.

RESPONSE:

The change between 2019 Test Year property taxes in the Evidentiary Update was not significant and does not impact the calculation in Schedule 16 for 2020 Property Taxes.

On page 2 of the Evidentiary Update, Creative Energy states "Creative Energy notes that its 2020 City of Vancouver property taxes will not be confirmed until June, 2020, and thus Creative Energy proposes that any differences between forecast and actual 2020 property taxes be deferred for future recovery or credit as required as part of Creative Energy's 2021 RRA".

17.3 Please discuss whether Creative Energy proposes to include any carrying costs on the proposed deferral account if it is approved. If yes, please explain what the proposed carrying cost is and why it is appropriate.

RESPONSE:

Yes, similar to other deferral accounts interest should be accrued on this account based on Creative Energy's short-term interest rate of 3.5% on the mid-year value.

Table 4 on page 2 of Appendix 1 to the Evidentiary Update shows the following variances in relation to property taxes:

Table 4 Update: Core Revenue Requirements – Summary of Component Rate Increase and Variance from 2018 Approved to 2020 RRA

2020 Rate Increase Components			
Cost Component	General Category of Cost Control	2018 Approved to 2019 RRA	Explanatory Variance of Overall Steam Rate Increase: 2018 Approved to 2020 RRA

Property Taxes	External	68,666	168,140	2.0%

17.4 Please provide an explanation for the variances provided in Table 4.

RESPONSE:

Between 2018 and 2019, the assessed value of Creative Energy's property increased 26 percent. The impact of this was approximately a $114,000 increase to property tax costs. This was offset by a decrease in mill rates. The utility rate decreased approximately 6% and the business and other utility rate by 14%.

For 2020, Creative Energy forecasts an increase property tax expense by 7.6% as described in the response to BCUC IR 17.2. The impact of this increase is approximately $60,000. An adjustment was also made to the reduction for non-regulated assets, an impact that increased the expense by $40,000. This adjustment relates to the fact that Creative Energy does not have rental income for its additional office space in 2020 and the allocation of property taxes related to this space has been removed.

18.0 Reference: CORE STEAM REVENUE REQUIREMENTS
Exhibit B-1, Section 3.8.2, p. 39; Appendix D
Capital Additions

On page 39 of the Application, Creative Energy provides the following table showing 2015 to 2018 Actual, and 2019 and 2020 Test Year capital additions for the Core Steam System:

Table 41: Core System Capital Additions

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Test Year	2020 Test Year
Total Capital Additions	957,101	1,506,832	436,695	1,173,038	2,107,017	1,648,917
Steam Plant					285,427	407,000
Distribution System					533,483	559,667
Customer Building Services					420,076	163,868
Customer Connections					868,032	518,382

18.1 Please define the scope of each capital addition category (e.g. Steam Plant, Distribution System) shown in Table 41. For example, are "Customer Building Services" referring only to equipment or assets found inside each customer building? Do "Customer Connections" refer to only the section of pipe connecting a customer building to the main steam line? Please explain.

RESPONSE:

The scope of each category is as follows:

- **Steam Plant**
  - **Beatty steam plant electrical, instrumentation or mechanical equipment used in the production of steam;**
- **Distribution System**
  - **Any piping, manhole or auxiliary equipment used in the steam distribution piping network;**
- **Customer Building Services**

- **Meter replacements, upgrades or pressure reducing station improvement; for example, the installation of a primary and secondary pressure reducing station where previously only a primary station was installed, or installation of an access platform (safety) to a pressure reducing station; and**

- **Customer Connections**
  - **Costs directly associated with adding a new customer, including the pipe section from existing steam mains to building mechanical room, pressure regulating station, Energy Transfer Station, meter station, equipment insulation, mechanical and electrical install, commissioning, permits, fees, and management.**

18.2 Please provide 2015 to 2018 Actual and Approved costs for each category of capital additions and the total capital additions.

RESPONSE:

Previous rate applications did not track customer connections separately nor does Creative Energy's accounting system track customer connections separately. Customer connections are generally included as part of customer building services. Please see below for comparison of the three categories:

	Plant		Distribution		Building Services and Customer Connections	
	Actual	**RRA**	**Actual**	**RRA**	**Actual**	**RRA**
2015	190,901	139,000	747	525,000	629,171	190,518
2016	276,503	670,500	305,739	925,000	914,069	410,000
2017	110,403	250,000	100,323	920,000	179,228	100,000
2018	316,994	254,600	759,802	936,928	69,636	101,840

In Appendix D, Creative Energy provides a detailed summary table of 2019 Test Year and 2020 Test Year capital additions.

18.3 Please identify all projects listed in Appendix D that are expected to incur costs over multiple years (i.e. multi-year projects).

RESPONSE:

The only multi-year project is the Remote Metering project. Some projects may span two fiscal years but are not considered multi-year projects if they start during one year and finish in the following year. Projects are not added to rate base until complete and in service. Schedule D therefore presents the actual 2019 and forecast 2020 capital additions as the amounts that are now in service or forecast to be in service by the end of 2020. Please refer to Attachment 18.5 for further detail.

Two of the projects listed in Appendix D will be added into rate base in multiple years as the projects are completed in phases. The remote metering project and the Vancouver Post Office projects are ongoing but are added to rate base as the parts of the project enter service.

18.3.1 Of these multi-year projects, please provide the total expected capital cost of each project.

RESPONSE:

The total expected capital cost of the remote metering project is approximately $750,000, of which Creative Energy proposes to add $293,666 to rate base in 2019 as associated with the assets placed into service since the project began in 2017. The project is forecast to be complete by the end of 2021.

18.4 Please identify any project listed in Appendix D that has been included and approved as part of any previous application reviewed by the BCUC.

RESPONSE:

The remote metering project was included in the 2016-2017 RRA and in the 2018-2022 RRA but it is through the proposed 2019 rates that Creative Energy seeks approval to commence recovery of the capital so far placed into service.

18.4.1 For the projects identified, please provide the BCUC order number, the approved cost, and an explanation for any variance between the previously approved forecast and current forecast costs for the 2019 and 2020 Test Years.

RESPONSE:

Creative Energy did not seek approval of the remote metering installations as it was within its base capital budget as part of the 2018-2022 RRA. At the time Creative Energy noted in response to a BCUC IR that the estimated remote metering project budget was $100,000/per year by virtue of the same amount being included in capital expenditures in the 2016-2017 RRA.

18.5 Please provide the following additional information for each "Steam Production Plant", "Steam Distribution System" and "Building Services" project listed in Appendix D:

i) Project description and scope of work;
ii) Project need and benefits to customers; and
iii) Construction start date and in-service date.

RESPONSE:

Please refer to Attachment 18.5 - Capital Additions Detail.

18.6 Please clarify whether the costs associated with the "Built space" project represent a one-time fee for implementation of this system or an on-going subscription.

RESPONSE:

Confirmed. The Built Space costs represent a one-time cost for build-out and implementation. Ongoing subscription is factored into operating costs.

18.6.1 Please explain why these costs are classified as capital costs (as opposed to operating costs).

RESPONSE:

The initial build-out is capital due to the enhanced operability and improvement on what was an antiquated system and setup, which included a new work order system, a photo directory of all assets, and location tracking with each tablet device for technician safety. The asset will be used for multiple years.

18.7 Please discuss any plant capacity limitations that may occur as a result of the proposed work on Boiler 6 in the 2020 Test Year.

RESPONSE:

No plant capacity limitations are expected, the work is being planned for normal boiler annual maintenance and it is not significant enough to require many months of downtime for the work to be performed.

In any given year, a summer shutdown schedule for Boiler 6 would be routinely 2 to 3 months. Boiler 6 is one of our largest Boilers (capacity of 200,000 pounds per hour with one burner only) and less efficient when operating below 50% capacity. The steam plant has other boilers that can carry the summer load as required.

18.7.1 Please describe the factors that led Creative Energy to determine that Boiler 6 required reliability and redundancy improvements. Please discuss any alternative strategies considered (e.g. other than Fan and VFD upgrade).

RESPONSE:

It is normal practice to conduct a more significant overhaul on one (and sometimes two) boiler(s) each year on a rotating basis. Boiler 6 has not had any significant work performed on it in the recent past, and work on the turbine (fan and VFD) was deemed necessary, with the various small repairs that have been done over the last several years charged to O&M.

18.7.2 The BCUC is currently reviewing a CPCN application regarding a Creative Energy Beatty-Expo Plant Project. Please describe any impacts that the outcome of this CPCN application may have on the Boiler 6 capital additions proposed for the 2020 Test Year in this Application. Similarly, please describe if and how the proposed capital additions associated with Boiler 3 would change as a result of the BCUC's decision on the Beatty-Expo Plant CPCN application.

RESPONSE:

There are expected to be no impacts to Boiler 6 or Boiler 3 as an outcome of the CPCN application and decision given that both will remain in place after the redevelopment.

18.8 Please discuss whether Creative Energy anticipates a future need of projects similar to the "MB-1 Manhole Rebuild" capital addition at other locations within the core steam distribution system. If so, please elaborate on any consideration given to project execution efficiencies (or challenges) that may be realized by completing similar projects concurrently.

RESPONSE:

Yes, several manholes are slated for refurbishment in the coming years and consideration has been given to project execution efficiencies to complete these projects concurrently to the extent practicable. The efficiencies will include completing one project while having already started another so that civil contractors' tasks may overlap on the job sites.

18.8.1 What factors led Creative Energy to determine the need to initiate a life extension project for this asset? What alternative strategies were considered?

RESPONSE:

Regular inspection of this manhole revealed its declining state of health. This manhole is along a major supply line of the distribution system and within this manhole are significant pieces of equipment that are vital to the safe operation of this section of the piping, including: a significant anchor point that is need of refurbishment; expansion joints that are required to be accessed for regular maintenance; and asbestos insulation removal that is part of the ongoing program to remove and replace the asbestos insulation identified within the distribution infrastructure. No other alternative strategies were considered.

18.9 Please elaborate on the "improved customer service" benefits of the "Remote Metering Project." Please also describe any operational cost savings anticipated as a result of this project, identifying the year in which these savings are anticipated to occur.

RESPONSE:

Steam service is metered by a steam meter, condensate meter, or a BTU meter located at a customer's building. The use of steam at our Customers premises is solely at the discretion of the building operators or demand of the building with little to no visibility by Creative Energy. The remote monitoring and metering are expected to be set up with email alerts for all monitored parameters out of range and this would include flow rates and meter accumulations.

The installation of the monitoring devices will provide:

- **Operations with real time data of steam regulating equipment, meters, and if needed or requested, other key operating parameters;**
- **Accounting with an integrated program that takes month end meter readings and downloads this data to a billing module; and**
- **Engineering with data that can be used to assess peak building loads and system loads.**

The entire Creative Energy network of systems is expected to be viewed from the web portal either from an individual computer screen or a centrally mounted flat screen TV.

Once a month, service engineers enter each building to read steam meters and the related savings from remote meter reading has been estimated to be $50,000 per year. Meters can also be read for billing purposes and accounting costs during the monthly meter reading and billing cycle are

estimated to save $10,600 per year. After the first day of meter reading any missed readings, reading errors, and failed meters are identified for further readings, repairs and estimations of consumption by accounting. The related impact is an estimated savings of $5,000 per year (accounting and operations combined). Calls for service are often vague with poor comprehension of how the steam delivery to any building occurs. Many calls for service are found to be unrelated to the steam delivery of the Creative Energy's equipment. Service calls could be reduced by Operations staff viewing in real time the associated equipment, potentially reducing calls at an estimated saving of $2,600 per year. The total yearly estimate of savings as above equals $68,065.

Customers may also benefit from real time metering information, with the ability to view and receive alerts when monitored equipment is out of normal operating parameters, by either the building operators and/or Creative Energy operations. This may allow a customer to compare their building to other similar buildings of size (square footage), function (residential, commercial, hotel), number of units (residential and hotel), and load services (heating, domestic hot water, laundry) to heating degree days. Customers may have access to their historical consumption, something that can be uploaded into the platform, which could be used to track their monthly and yearly efficiency of each building and to assist in preparing budgets.

In Appendix D of the Application, Creative Energy provides a breakdown of the capital costs associated with customer connections. The applicable subsection of Appendix D is reproduced below:

Customer Connections			
Vancouver Post Office DPS	868,032	70,000	Relocating existing line due to Post Office construction to maintain service to two existing customers and one new customer
410 West Georgia		249,862	New customer load
402 Dunsmuir		100,920	New customer load
YWCA		97,600	New customer load
Subtotal	868,032	518,382	

18.10 Please provide the following for the 2019 Test Year "Customer Connections" costs of $868,032:

i) Detailed scope of work and cost break down, including accuracy level;
ii) Map(s) showing the existing system and the planned new work. Please include any planned line relocations, line extensions, existing and new customer locations and any other relevant information related to the capital expenditure;
iii) Customers to which costs are attributed. If attributable to multiple customers, please provide a breakdown of cost allocation for each customer;
iv) The incremental new load (MWh) forecasted for each customer. Please also include the expected timeline for the forecasted load additions; and
v) Confirmation of whether these capital additions are in-service.

RESPONSE:

i) The Scope of work is as follows and as reflected in the table below reflecting current estimates, noting that the proposed amount to add to rate base in 2019 remains based on initial projections (as summarized in Appendix D):

a. Install new underground steam service on Homer street from Georgia street to existing service feeding the existing building 401 W Georgia. The new steam service on Homer street would supply the existing 401 W Georgia site, and the new developments at 402 Dunsmuir and 349 W Georgia;

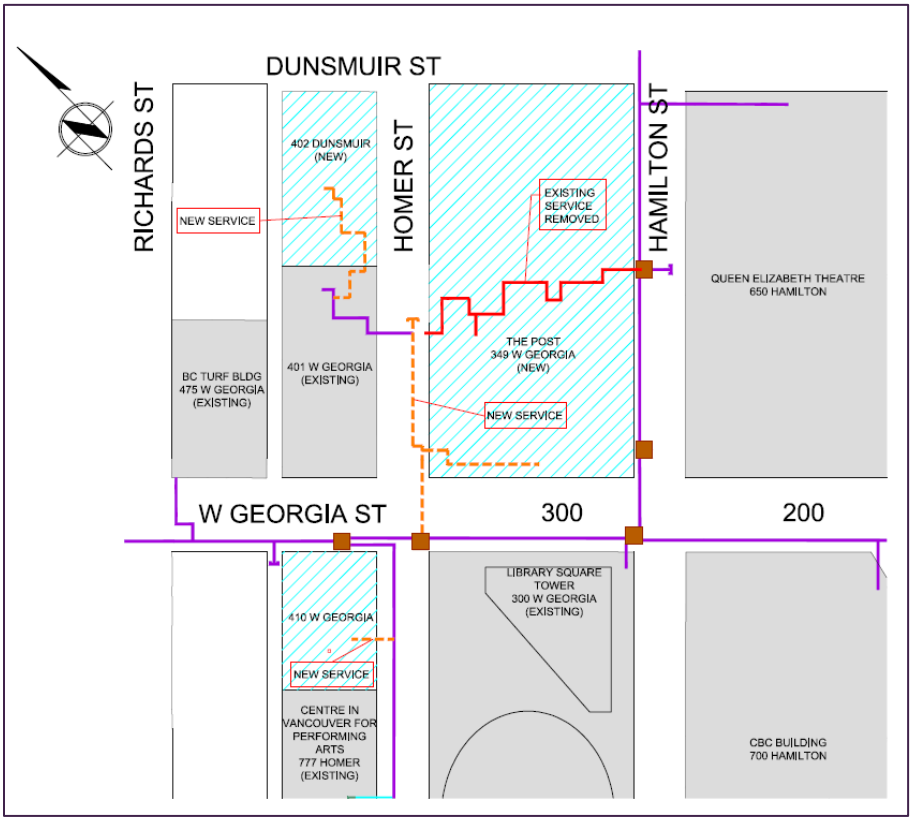
b. Install above ground piping from 401 W Georgia to 402 Dunsmuir including pressure

regulating station;

c. **Install new underground service on Homer street to service 410 W Georgia;**
d. **Planning for YWCA Expansion steam connection. The YWCA on Beatty street is an existing customer of Creative Energy. YWCA is adding a new wing to their hotel in 2020 which requires steam service.**

Customer Connections	Xost Category	Cost to the end of 2019	Forecast 2020 (+/- 20%)
Vancouver Post Office			
	Construction	753,856	-
	OSE	82,514	-
	Engineering/Management	155,508	135,000
	Total	**991,878**	**135,000**
410 W Georgia			
	Construction	49,447	180,000
	OSE	2,744	35,000
	Legal	960	-
	Engineering/Management	12,952	35,000
	Total	**66,103**	**250,000**
402 Dunsmuir			
	Construction	72,325	25,000
	OSE	19,775	-
	Engineering/Management	7,158	10,000
	Total	**99,258**	**35,000**
YWCA			3,465
	Construction	-	50,000
	OSE	-	15,000
	Engineering/Management	3,465	17,000
	Total	3,465	82,000
subtotal		**1,160,704**	**502,000**

ii) Please refer to the following map.



iii) Please refer to the table above for a reporting of the costs by customer connection.

iv) Please refer to the response to BCUC IR 18.12

v)

- **YWCA – not in service**
- **Vancouver Post office – DPS in service**
- **410 W Georgia – not in service**
- **402 Dunsmuir – not in service**

Please refer to the response to BCUC IRs 18.3 and 18.12 and to the Application at section 3.8.2 for further discussion of the components of customer connections forecast to be added to rate base.

18.11 Please provide the following for each of the "Customer Connections" costs listed in the 2020 Test Year:

i) Detailed scope of work and cost break down, including accuracy level;
ii) Map(s) showing the existing system and the planned new work. Please include any planned line relocations, line extensions, existing and new customer locations and any other relevant information related to the capital expenditure;
iii) The incremental new load (MWh) forecasted for each customer. Please also include the expected timeline for the forecasted load additions; and
Confirmation that these capital additions will be in-service by the end of the 2020 Test Year.

RESPONSE:

Please refer to the response to BCUC IR 18.10.

18.12 Please discuss the expected load changes resulting from the service renewal at the former Vancouver Post Office Building. Please include in your response:

i) Historical load for this customer;
ii) Forecast future load for this customer and expected timeframes; and
iii) Whether the forecast future load is included in the Application. If not, please explain why not.

RESPONSE:

The Post Office project at 349 W Georgia is forecast to demand 8,305 M# per year. In 2017, the last full year of operations, 349 W Georgia used 15,746 M#'s load. Average load from 2008-2017 was 11,334 M#.

- **The Post Office project supports connection of 401 W Georgia and 402 Dunsmuir, which are forecast to demand 3,000 M# and 1,973 M#, respectively.**
- **402 Dunsmuir is anticipated to start operating during 2020, while 410 W Georgia and 349 W Georgia are forecast to being taking service in 2021 and 2022, respectively.**
- **The 2020 load forecast incorporates a partial year for new load in 2020 at 402 Dunsmuir.**

19.0 Reference: CORE STEAM REVENUE REQUIREMENTS
Exhibit B-1, Section 3.8.3. p. 40
Allowance for Funds Used During Construction (AFUDC)

On page 40 of the Application, Creative Energy states that "2019 and 2020 capital additions do not include AFUDC."

19.1 Given the statement "2019 and 2020 capital additions do not include AFUDC", please confirm whether this means that the capital additions proposed in this Application will go into service during the test years in which they are reported. If not confirmed, please explain the statement.

RESPONSE:

Confirmed.

20.0 Reference: CORE STEAM REVENUE REQUIREMENTS
Exhibit B-1, Section 3.8.5, p. 41
Contributions in Aid of Construction

On page 41 of the Application, Creative Energy states:

> A customer may be required to make a financial contribution to extend utility services, a Contribution in Aid of Construction, if the incremental cost of extending the service exceeds forecast incremental revenue over the planned or contracted period of service duration. When required, such contributions protect existing customers from subsidizing the costs of new customer connections.

Creative Energy also states on page 41:

> Creative Energy does not forecast any new CIAC additions during the test period of this Application.

20.1 Please explain how Creative Energy's extension policy adheres to the BCUC's Utility System Extension Test Guidelines and the BCUC's Thermal Energy System Guidelines.[4]

RESPONSE:

The referenced paragraph above articulates the principle that Creative Energy adheres to when assessing the costs of extending service to connect a new, single customer to its Core Steam system; that being that existing customers ought to be better-off from the addition of the new customer and at minimum no worse off. Creative Energy considers that its approach to such extensions of service is aligned to the principles and conclusions set out in the BCUC's Utility System Extension Test Guidelines.

Creative Energy acknowledges that the TES Guidelines set out requirements for when a CPCN application may be required in respect of capital additions to Stream B TES systems of a material dollar amount to provide additional capacity to meet increased demand. There are no considerations nor circumstances applicable to Creative Energy's Core steam network to which those requirements currently apply.

[4] Guidelines may be found on BCUC's website https://www.bcuc.com/resources/guidelines.html

20.2 Please provide the Contribution in Aid of Construction cost analysis for each new customer to be connected during the 2019 and 2020 Test Years.

RESPONSE:

The cost analysis of the extension to 402 Dunsmuir is as follows, based on a 30-year contract and 2019 rates escalating at 2 percent inflation per year. On the basis of the results no Contribution in Aid of Construction was deemed necessary.

402 Dunsmuir	NPV
Capital	(149,758)
Maintenance	(30,759)
Municipal Access Fee	(2,248)
Revenue	179,860
Net	(2,905)

The cost analysis of the extension to the YWCA addition at 733 Beatty is as follows, based on a 25-year contract and 2019 rates escalating at 2 percent inflation per year. Under the circumstances of renewing a 25-year contract for both the existing and new load at 733 Beatty and on the basis of the overall results, no Contribution in Aid of Construction was deemed necessary.

YWCA Addition - 733 Beatty	NPV
Capital	(88,658)
Maintenance	(8,369)
Municipal Access Fee	(1,068)
Revenue (incremental load)	85,447
Net	(12,648)

On page 41 of the Application, Creative Energy provides the following table for Core Steam System Contributions in Aid of Construction for 2015 to 2018 Actual and 2019 and 2020 Test Year:

Table 42: Contributions in Aid of Construction

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Test Year	2020 Test Year
Gross CIAC						
Opening Balance	(922,397)	(922,397)	(1,052,385)	(1,256,385)	(1,256,385)	(1,256,385)
Repayments						
Additions		(129,988)	(204,000)			
Closing Balance	(922,397)	(1,052,385)	(1,256,385)	(1,256,385)	(1,256,385)	(1,256,385)
Accumulated Depreciation						
Opening Balance	253,218	270,376	287,534	304,692	336,102	367,512
Depreciation	17,158	17,158	17,158	31,410	31,410	31,410
Closing Balance	270,376	287,534	304,692	336,102	367,512	398,922
Net CIAC						
Opening Balance	(669,179)	(652,021)	(764,852)	(951,693)	(920,283)	(888,873)
Closing Balance	(652,021)	(764,851)	(951,693)	(920,283)	(888,873)	(857,463)
Net Mid-Year CIAC	(660,600)	(708,436)	(858,273)	(935,988)	(904,578)	(873,168)

20.3 Please explain Creative Energy's method for depreciating CIAC. Why is Actual CIAC depreciation the same in the years 2015, 2016 and 2017 Actual, and also the same for 2018 Actual and 2019 and 2020 Test Years?

RESPONSE:

CIAC is depreciated on a straight-line basis over 40 years. It is calculated by multiplying the opening balance of gross CIAC by 2.5%. The amount of CIAC depreciated for a year will change in the year after new additions are made to the total balance. This is the same approach used for depreciation of plant in service.

20.3.1 Please explain why the CIAC additions in 2016 and 2017 Actual ($129,988 and $204,000, respectively) do not have different impacts on the amount of CIAC depreciation in later years.

RESPONSE:

In response to this IR, Creative Energy has assessed that the prior record of depreciation of CIAC, as reported in the GL and summarized in Table 42 above, was not calculated correctly for 2015-2017. Depreciation should have been $23,060 in 2015, $23,060 in 2016 and $26,310 in 2017.

21.0 Reference: NON-RATE BASE DEFERRALS AND DEFERRAL ACCOUNT RATE RIDER
Exhibit B-1-1, Appendix 1, pp. 4–5; Exhibit B-1, Sections 3.2.3.2, 5.2, pp. 25–27, 48; Exhibit A2-1, p. 1
Pension Expense Deferral Account

BCUC staff extracted the following from Table 15 on page 4 of Appendix 1 to the Evidentiary Update:

Table 15 Update: Total O&M by Cost Driver and Control

	Category of Cost Control	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2018 Approved	2019 Test Year	2020 Test Year
Pension revaluation		95,200	(59,600)	246,400	403,700	-	-	5,126,308

In Exhibit A2-1, Creative Energy states:

Information about the Company's defined benefit pension is as follows:

	2018 $	2017 $
Pension expense		
Current service costs	251,954	245,000
Finance cost	(25,100)	(29,600)
Remeasurement and other items	403,700	246,400

21.1 Please confirm, or explain otherwise, that the Actual 2017 and 2018 "Pension revaluation" amounts shown in Table 15 from the Evidentiary Update are incorrectly labelled and should instead be labeled pension "Remeasurement and other items" as shown in Exhibit A2-1 (considering these are the same amounts).

RESPONSE:

Confirmed.

21.2 Please confirm, or explain otherwise, that there is a typographical error in Table 15 from the Evidentiary Update in that the $5,126,308 for the 2020 Test Year is the total forecast O&M for the 2020 Test Year (i.e. the $5,126,308 does <u>not</u> specifically relate to pensions).

RESPONSE:

Confirmed. This is a typographical error. The balance in this cell should be zero.

21.2.1 If not confirmed, please provide supporting evidence for the $5,126,308 for the 2020 Test Year and explain the increase between Actual 2018 and forecast 2020 Test Year.

RESPONSE:

Not applicable.

21.3 Please explain if any pension remeasurements can be forecast or expected for the 2019 Test Year. If not, why not?

RESPONSE:

The remeasurement cannot be forecast in advance. Actual remeasurement has become available subsequent to the Evidentiary Update. The 2019 remeasurement and other items line is a gain of $446,700.

On page 48 of the Application, Creative Energy states:

> In 2018, current service costs on the pension were $25,776 lower than Approved [2018 current service costs]. However, there was a revaluation of the pension asset for $403,700 as the return on plan asset was not sufficient to cover the interest expense on pension liability.

21.4 Please confirm, or explain otherwise, that the $403,700 in pension revaluation costs in 2018 were due to the actual return on plan assets being lower than expected. If confirmed, but there are other items included in this figure as well, please provide a breakdown of each.

RESPONSE:

During 2018, there was a loss on plan assets. Therefore, the value of the net defined benefit pension assets decreased by both the loss on plan assets and the interest on the defined benefit obligation. The remeasurement and other items also includes costs paid to the Creative Energy's actuary and administrator.

The remeasurement and other items includes the following amounts:

Interest on defined benefit obligations	-	269,100
Return (loss) on Plan Assets	-	59,500
Finance Costs	-	25,100
Administrative Costs	-	50,000
	-	403,700

21.4.1 Please confirm, or explain otherwise, that the pension revaluation costs are provided by an actuary. If confirmed, please provide the name of the actuarial services firm. If not confirmed, please explain why not and how Creative Energy determined the pension revaluation cost.

RESPONSE:

Creative Energy utilizes actuaries from Aon to prepare a CPA Section 3462 Disclosure Information each year. The interest on defined benefit obligations and return (loss) on plan assets is included in the report provided by Aon.

On page 48 of the Application, Creative Energy also states:

> A portion of the actual pension costs are allocated to capital costs and projects other than the Core steam system. As such, actual pension costs used for calculating the deferral account balance are lower than the expense in the notes to the 2018 audited financial statements. [*Emphasis Added*]

In Exhibit A2-1, Creative Energy states:

Information about the Company's defined benefit pension is as follows:

	2018 $	2017 $
Pension expense		
Current service costs	251,954	245,000
Finance cost	(25,100)	(29,600)
Remeasurement and other items	403,700	246,400
	630,554	461,800

On page 48 of the Application, Creative Energy provides the following Table:

Table 51: Pension Expense Deferral Account Variances

Description	2017 Approved	Inflation Factor	2018 Approved	2018 Actual	Deferral
Plant	100,130	1.84%	101,972	98,280	(3,692)
Service	28,124	1.84%	28,641	27,181	(1,460)
Management	58,593	1.84%	59,671	39,088	(20,583)
Revaluation				403,700	403,700
Total	186,846		190,284	568,249	377,966

21.5 Please confirm, or explain otherwise, that $62,305 (calculated as $630,554 from the total 2018 Pension Expense in Exhibit A2-1 minus $568,249 from the total 2018 Actual Pension Expense shown in Table 51) was allocated to "capital costs and projects other than the Core Steam System."

RESPONSE:

Confirmed.

The Current service costs line from Exhibit A2-1 of $251,954 is presented to include the Finance Costs of $25,100. The second line splits out the finance costs. The costs of $25,100 are also included in the $403,700 Remeasurement and Other items line. In effect, the Finance costs are being removed from current service costs and are being added into remeasurement and other items. Thus, current service costs are $226,854. Of the current service costs, $164,549 were expensed to the Core system. The

remaining $62,305 was capitalized to Core capital expenditures, allocated using Massachusetts formula to other energy systems or transferred to projects in Creative Energy Developments LP. The total expense in 2018 also includes the remeasurement and other items $403,700 for a total of $568,249.

21.5.1 Please provide a breakdown of the allocation by cost and project.

RESPONSE:

The allocation to individual projects has not been quantified. However, it can be broken out to the following categories:

- **Core Capital Projects: $25,815**
- **Other operating energy systems via the Massachusetts formula: $5,074**
- **Projects in Creative Energy Developments LP: $31,414**

21.5.2 Is any of the $62,305 included in Creative Energy's 2018 rate base?

RESPONSE:

Yes, project management time is capitalized to maintenance capex projects and new customer connections, which is added to rate base. The rate charged to capital projects is loaded to include all payroll related costs including benefits and pension costs. Please refer to the response to BCUC 21.5.1.

Table 17 on page 4 of Appendix 1 to the Evidentiary Update shows the following pension costs for Steam Production staff [with emphasis added]:

Table 17 Update: Steam Production Supervision and Labour – Account 500 - Summary

500 Supervision and Labour	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2018 Approved	2019 Test Year	2020 Test Year
Wages	1,030,544	1,075,306	1,165,332	1,130,144	1,181,190	1,226,794	1,225,290
Overtime	23,328	24,244	36,001	66,696		31,595	53,692
Benefits	77,527	95,189	101,466	103,999	103,593	142,937	136,089
Pension Costs	89,182	85,462	87,433	98,280	101,972	137,901	151,162
Pension Revaluation			100,050	174,899			
Total	1,220,581	1,280,201	1,490,282	1,574,018	1,386,755	1,539,227	1,566,232

On pages 25 of the Application, Creative Energy states:

> Pension costs have also increased from 2018 Approved cost as the contribution rate has increased. Calculations are based on the expectation that all plant staff will enroll in the program.

Table 19 on page 4 of Appendix 1 to the Evidentiary Update shows the following pension costs for Distribution staff [with emphasis added]:

Table 19 Update: Distribution Supervision and Labour – Account 870 - Summary

870 Supervision and Labour	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2018 Approved	2019 Test Year	2020 Test Year
Wages	472,340	447,368	404,526	447,044	469,429	462,458	515,940
Overtime	3,568	3,642	6,854	20,319	10,400	18,615	22,403
Benefits	39,117	39,768	30,550	38,748	41,364	56,826	55,804
Pension	36,002	38,362	32,589	27,181	28,641	54,664	68,611
Pension Revaluation			45,756	59,351			
Total	551,027	529,141	520,275	592,644	549,834	592,563	662,757

On page 26 of the Application, Creative Energy states:

> Pension costs have also increased from the 2018 Approved cost as the contribution rate has increased. Calculations are based on the expectation that all Distribution staff will enroll in the program.

21.6 What is the amount of the increase in contribution rates for Steam Production and Distribution staff in 2019 and 2020?

RESPONSE:

Contribution rate is the percentage that Creative Energy must contribute to the pension on the total wages for each employee enrolled in the plan. This question may be confusing contribution rate with the percentage of employees who were enrolled in the plan.

The contribution rate in 2018, 2019 and 2020 was 11% of employee wages for those enrolled in the plan. The 2018 approved cost was based on the 2017 approved costs plus inflation. However, the contribution rate increased from 2017 and 2018. The inflation increase from 2017 approved would only pick up the increase in employee wages. It would not take into account higher current service costs related to the contribution rate increasing. The impact of this was offset by the fact that not all employees were enrolled in the plan during 2018 as some were new employees were new and were not eligible to join the plan until later in the year.

21.6.1 Please discuss the rationale for the increasing contribution rate in 2019 and 2020.

RESPONSE:

The contribution rate in 2019 and 2020 did not increase from 2018. It is 11% for all three years as described in the response to BCUC IR 21.1. The number of plant and distribution employees enrolled in the plan has increased.

21.7 Please provide the numbers of additional Steam and Distribution staff who joined the company in 2018. How many are expected to join the pension plan in 2019 and 2020?

RESPONSE:

Three Steam plant and two Distribution staff joined in 2018. One additional employee was hired for the Distribution team and is also expected to enroll in 2020.

Table 21 on page 5 of Appendix 1 to the Evidentiary Update shows the following pension costs for Management [with emphasis added]:

Table 21 Update: Management Labour and Benefits – Accounts 920 and 926 - Summary

920 Admin & General Salaries	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2018 Approved	2019 Test Year	2020 Test Year
Wages	784,491	593,410	496,221	551,172	648,236	527,415	676,042
926 Employee Benefits							
Benefits	47,467	60,448	56,351	44,907	47,950	58,976	64,826
Pension	17,263	69,351	51,130	39,088	59,671	27,449	22,746
Pension Revaluation	95,200	(59,600)	100,593	169,450			
Subtotal Total	159,930	70,199	208,074	253,445	107,621	86,426	87,573
Total	944,421	663,609	704,295	804,617	755,857	613,840	763,614

On page 27 of the Application, Creative Energy states:

> Conversely, estimated pension costs are significantly lower than 2018 Approved as fewer management team members are enrolled in the pension. The pension plan was discontinued for new members of the management team in 2018 and only those employees that were with the company prior to it being discontinued still receive this benefit.

21.8 Please confirm, or explain otherwise, that the pension plan is closed to new members of the management team but that the pension plan has not been terminated.

RESPONSE:

The pension plan has not been terminated. Some management and administrative staff are still in the pension plan. Management and administrative staff that started working for Creative Energy prior to July 2018 will continue to be in the plan and new employees hired since then are not in the plan.

21.8.1 If confirmed, please also confirm, or explain otherwise, that the pension plan remains open to new Steam Production and Distribution staff.

RESPONSE:

The pension plan remains open to new Steam Production and Distribution staff.

21.9 Please explain what impact the discontinuation of the pension plan for new members of the management team has had on the funded status of the pension plan and what impact it will have on the remeasurement expense.

RESPONSE:

The discontinuation of the pension plan for new members of the management team has had no impact on the funded status of the pension plan. It has no impact on the remeasurement expense.

21.10 Please provide the following details of the pension plan:

a) Number of Active Plan Members split between Steam Production, Distribution and Management staff; and
b) Does the plan have mandatory enrollment, or may employees opt in/out at any time?

RESPONSE:

a) The plan has the following active members:

Management:	**7**
Steam Production:	**15**
Distribution:	**6**

b) The plan does not have mandatory enrollment. However, once an employee is enrolled, they cannot opt out unless they quit or are terminated.

On page 48 of the Application, Creative Energy provides the following table:

Table 51: Pension Expense Deferral Account Variances

Description	2017 Approved	Inflation Factor	2018 Approved	2018 Actual	Deferral
Plant	100,130	1.84%	101,972	98,280	(3,692)
Service	28,124	1.84%	28,641	27,181	(1,460)
Management	58,593	1.84%	59,671	39,088	(20,583)
Revaluation				403,700	403,700
Total	186,846		190,284	568,249	377,966

On page 48 of the Application, Creative Energy states:

> In 2018, [actual] pension costs were $377,924 higher than approved… Approved pension costs for 2017 were derived from the 2017 Approved costs with inflation of 1.84 percent added as directed by the Commission when finalizing 2018 Core Steam rates… In 2018, current service costs on the pension were $25,776 lower than Approved.

21.11 Please confirm, or explain otherwise, that the $377,924 stated on page 48 of the Application should be $377,966 as shown in Table 51 of the Application.

RESPONSE:

Confirmed.

21.12 Please confirm, or explain otherwise, that there is a typographical error on page 48 in that "Approved pension costs for 2017 were derived from the 2017 Approved costs…" should read "Approved pension costs for 2018 were derived from the 2017 Approved costs…"

RESPONSE:

Confirmed.

21.13 Please confirm, or explain otherwise, that the $25,776 stated on page 48 of the Application should be $25,735 (calculated as the sum of the deferral amounts of $3,692 + $1,460 + $20,583), corresponding to Table 51.

RESPONSE:

Confirmed.

22.0 Reference: NON-RATE BASE DEFERRALS AND DEFERRAL ACCOUNT RATE RIDER
Creative Energy 2016-2017 RRA Decision, pp. 48, 50; Exhibit B-1, Section 1.1, 2.1, 5.3, pp. 3, 14, 48–49; Exhibit B-1-1, p. 2
Third Party Regulatory Costs Deferral Account (TPRCDA)

On page 50 of the Creative Energy 2016-2017 RRA Decision, the BCUC states:

> In all future revenue requirements applications (RRA) Creative Energy is directed to provide a comprehensive explanation for each deferred expense item as follows: a detailed description of the expense item; a justification as to why the particular variance is eligible to be included in the TPRCDA; and an explanation of why the expense item was greater or less than forecast."

On page 48 of the Application, Creative Energy provided the following table:

Table 52: Third Party Regulatory Costs Deferral Account Variances

Description	2017 Approved	Inflation Factor	2018 Approved	2018 Actual	Deferral
BCUC Quarterly Fees	43,000	1.84%	43,791	23,435	(20,357)
BCUC RRA Fees 2018	15,000	1.84%	15,276	24,132	8,856
RRA Consulting Support	48,000	1.84%	48,883	20,366	(28,517)
PACA - CEC/BCOAPC	27,200	1.84%	27,700	52,472	24,771
RRA Legal Fees				95,812	95,812
RNG Application				2,329	2,329
BCUC LTRP review				2,996	2,996
Beatty CPCN BCUC				121,768	121,768
Subtotal	133,200		135,651	343,309	207,659
BCUC Review of Beatty CPCN in 2019 - partial					45,741
Total (not including interest)					253,400

Creative Energy states on page 14 of the Application that "[t]he NEFC system is thus both a customer of the Core Steam system and a separate service area with its own Commission-approved revenue requirements and rates for hot water service".

22.1 Please explain whether any allocations were made to the amounts shown in Table 52 in the "2018 Actual" column to separate the fees between the NEFC and Core Steam System. If yes, please explain how the amount of the adjustment was determined for each cost.

RESPONSE:

No allocations were made to NEFC or other energy systems related to regulatory costs. The NEFC is a customer of the Core steam system and the noted regulatory costs are applicable to the Core system.

22.2 Regarding 2018 Actual "RRA Consulting Support" in Table 52 ($20,366), please provide a breakdown of the consultants who provided this service and clarify to which RRA application(s) this support relates.

RESPONSE:

All consulting support was provided by Reshape Infrastructure Strategies for services related to the 2018-2022 Core RRA.

22.3 In respect to the 2018 Actual "RRA Legal Fees" in Table 52, please: (a) explain what legal entity provided these services; (b) identify which RRA proceeding(s) these fees relate; and (c) provide supporting documentation for the legal services provided.

RESPONSE:

Services were provided by McCarthy Tetrault and related to the 2018-2022 Core RRA. Please refer to Attachment 22.3.

22.4 Please provide a breakdown for the "Beatty CPCN BCUC" costs included in Table 52 (e.g. consulting, external legal, and regulatory costs). Please provide supporting documentation for the work done within each category of costs.

RESPONSE:

The recorded costs were costs invoiced by the BCUC. There are no consulting costs or legal costs included in the referenced figure.

July 2018	**$2,113**
August 2018	**$10,353**
September 2018	**$13,458**
October 2018	**$56,305**
November 2018	**$10,267**
December 2018	**$29,273**
Total	**$121,769**

On page 49 of the Application, Creative Energy states "[t]he two most significant costs [in 2018 Actual] were the Commission costs, intervenor costs and consulting and legal fees for the 2018 Revenue Requirement Application totaling $194,782..."

22.5 Please confirm, or explain otherwise, that there is typographical error on page 49 of the Application in that the $194,782 should be $192,782.

RESPONSE:

Confirmed.

In the footnote to Table 2 on page 3 of the Application, Creative Energy states that the revenue collected in the 2019 RRA is less than the revenue required as it "reflects the proposal to set 2019 rates equal to the interim approved level of $7.65 [per thousand pounds of steam] given projected load <u>and to concurrently record an addition to the Third-Party Regulatory Costs Deferral Account in the amount of the difference of ($45,742)</u> for recovery through the DARR [Deferral Account Rate Rider] beginning in 2020." [*Emphasis Added*]

On page 48 of the Creative Energy 2016-2017 RRA Decision, the BCUC states, "[t]he Panel approves the creation of a TPRCDA specifically limited to capture the <u>annual variance between forecasted and actual third party costs</u> relating to regulatory filings and proceedings required under the UCA, with a <u>one year amortization period</u> at a short term debt carrying cost." [*Emphasis added*]

22.6 Please provide justification as to why the amounts outlined in red in the Table 52 above should be added to the TPRCDA given that no costs were forecasted for these regulatory proceedings in 2018.

RESPONSE:

The amounts outlined in red are the reasonably incurred regulatory costs required to support Creative Energy's applications before the Commission as a regulated public utility as governed by the *Utilities Commission Act* and in accordance with the Commission's jurisdiction under the Act.

22.6.1 Please discuss whether allowing actual regulatory costs to flow into the TPRCDA is contrary to the purpose that the TPRCDA was established for. Please explain why or why not.

RESPONSE:

Creative Energy disagrees with the premise of this question if it suggests that any actual regulatory cost or proceeding that is not at first forecast in a previous RRA ought to be excluded from recovery through the TPRCDA. The TPRCDA captures the variance between forecast and actual third party costs relating to regulatory filings and proceedings required under the Act, which necessarily and appropriately means that it will also capture the variance related to filings and proceedings that may not have been contemplated or otherwise forecast in a previous RRA.

Further to the response to BCUC IR 22.6, there are no current Creative Energy staff that supported the development of the 2018-2022 RRA and it is therefore unclear as to why in the context of that application there were not costs forecast for review of the Beatty Redevelopment CPCN, for example. Be that as it may however, the only effect of that approach was to exclude those costs from the 2018 test period rates as permanently approved by the Commission. The effect is not to suggest that the actual costs were not reasonably incurred nor otherwise ineligible for recovery under the TPRCDA as per the intent of the deferral account.

On page 2 of the Evidentiary Update, Creative Energy states "[it] proposes to add an additional amount of $39,499 to the opening balance of the amounts to be recovered through the Deferral Account Rate Rider (DARR); that is, the addition of that amount to the Third-Party Regulatory Costs Deferral Account". Creative Energy states that the effect of the updates is to "[i]ncrease the revenue deficiency at the proposed rate to $85,241 from $45,742."

22.7 Please confirm, or explain otherwise, that the only change to Table 52 based on the Evidentiary Update is that the "BCUC Review of Beatty CPCN in 2019 - partial" amount of $45,741 should be revised to the proposed amount of $85,241. If confirmed, please provide an updated Table 52.

RESPONSE:

Confirmed. Please refer to the Table 52 Update below.

Table 52 Update : Third Party Regulatory Costs Deferral Account Variances

Description	2017 Approved	Inflation Factor	2018 Approved	2018 Actual	Deferral
BCUC Quarterly Fees	43,000	1.84%	43,791	23,435	(20,357)
BCUC RRA Fees 2018	15,000	1.84%	15,276	24,132	8,856
RRA Consulting Support	48,000	1.84%	48,883	20,366	(28,517)
PACA - CEC/BCOAPC	27,200	1.84%	27,700	52,472	24,771
RRA Legal Fees				95,812	95,812
RNG Application				2,329	2,329
BCUC LTRP review				2,996	2,996
Beatty CPCN BCUC				121,768	121,768
Subtotal	133,200		135,651	343,309	207,659
BCUC Review of Beatty CPCN in 2019 - partial					85,241
Total (not including interest)					292,890

22.7.1 If confirmed, please provide a breakdown and description of the expenses that the $85,241 relates to and justification as to why these amounts are eligible to be included in the TPRCDA.

RESPONSE:

Please refer to the response to BCUC IR 2.2.

22.7.2 If not confirmed, please provide the information requested in the IR above for the $45,741.

RESPONSE:

Not applicable. Please refer to the responses to BCUC IRs 22.7.1 and 2.2.

22.8 In the event that the proposed DARR is not approved, please provide the overall rate impact of the TPRCDA balance ($253,400) on Steam Rates amortized over one-, two- and three-years.

RESPONSE:

If the TPRCDA balance of $253,400 was amortized for recovery through the steam rate instead of through the DARR, recovery over a 1-year period would increase the average steam rate by increase 7.2% compared to 2019, over 2 years by 5.7% compared to 2019 and over 3 years by 5.3% compared to 2019.

23.0 Reference: NON-RATE BASE DEFERRALS AND DEFERRAL ACCOUNT RATE RIDER
Exhibit B-1, Section 1.1, 1.1.1.5, 5.1, 5.4, pp. 1, 7, 47–49; Exhibit B-1-1, p. 2; Appendix 1, p. 7
DARR

On page 1 of the Application, Creative Energy requests approval, among other things, to "establish a new rate rider (the Deferral Account Rate Rider or DARR), effective January 1, 2020, to recover non-rate base regulatory and pension-related deferred costs from Core Steam system customers, with the level of the DARR set to recover the balance over a two-year amortization."

On page 7 of the Application, Creative Energy states "[t]he objective of the rate rider mechanism and two-year amortization is to target smooth and stable recovery of these irregular regulatory and pension cost impacts". Creative Energy also states that under "the proposed DARR, these costs will be recovered from Core Steam customers on a single per unit basis ($/M#) ... This approach will promote more equitable allocation of cost recovery from customers and more predictable cost recovery by the utility."

23.1 Please elaborate on why a new rate rider (DARR) is appropriate to recover the non-rate base regulatory and pension-related deferred costs from Core Steam system customers.

RESPONSE:

Rate Riders, of which the DARR is no exception, are simple and readily understood rate mechanisms to recover discrete costs such as those that are appropriate for deferral account treatment. They provide a mechanism for the recovery of discrete costs separate from the base rates, the ability to quickly adjust the level of the rate rider and, if applicable, cancel the rate rider when the subject costs

have been recovered. They also support transparency and rate and revenue stability over time.

For example, in its Decision into Creative Energy's 2016-2017 RRA issued under Order G-167-16, the Commission directed Creative Energy to establish a Fuel Cost Stabilization Account (FCSA) to record variances between forecast and actual fuel costs and a fuel cost rate rider mechanism to recover or distribute excess balances in the FCSA when required, subject to an application for approval of the level of the rate rider and amortization period when required.

23.2 Please discuss any alternatives to the proposed DARR that Creative Energy has considered, including the pros and cons of each and why they were rejected (e.g. increase Steam Rates).

RESPONSE:

Creative Energy proposed the DARR with a view of the merits described in the Application and as elaborated in the response to BCUC IR 23.1, which it considers to be the overall benefit of a rate mechanism relative to the alternative of recovering deferral account balances through an adjustment to the declining block steam rate.

The other alternative is a rate rider using a different billing determinant. For example, a basic recovery charge (e.g., $/day) that would be the same for each Core steam customer was regarded to be unfair to smaller customers and was thus not considered in any meaningful way.

23.3 Please provide further justification for proposing to recover these deferred costs over a two-year amortization period.

RESPONSE:

A two-year amortization period allowed a DARR to be put into place such that the overall rate impact in 2020 was less than 10 percent.

A one-year amortization period would advance the recovery of costs in closer alignment to the period over which costs were incurred but increases the 2020 rate impact of the DARR, as shown in the response to BCUC IR 23.6. A three-year amortization would marginally lessen the overall percentage rate impact of the DARR (from 3.8% to 2.7%), but further extend the lag in cost recovery from customers for the period in question. In Creative Energy's view a two-year amortization reasonably balances such competing objectives and is consistent with the Commission's recent decision into a final fuel cost rate rider for Creative Energy, as issued under Order G-226-19, approving a two-year amortization period in that case.

23.4 Please provide the overall rate increase in 2020 based on the proposed two-year amortization of the DARR, in an excel spreadsheet.

RESPONSE:

The calculated rate increase of the DARR in 2020, 3.8% as reported in Table 10 of the Application, is equal to the level of the DARR in 2020, $0.29/M#, divided by the average approved steam rate in 2018 and interim approved and proposed final 2019 steam rate, of $7.65/M#.

The sum of the steam rate impact in 2020 and the DARR rate impact in 2020 equals 8 percent (4.2% plus 3.8%, respectively).

23.5 Please elaborate on why "[t]his approach will promote more equitable allocation of cost recovery from customers."

RESPONSE:

The DARR promotes more equitable allocation of cost recovery from customers as, by comparison, recovery of the deferral account balances through the declining block steam rate would necessarily mean that larger customers achieve a relative discount on their contribution to the recovery of the pension-related and regulatory costs recorded to the deferral accounts.

A basic monthly recovery charge (e.g., a $/day charge) that does not vary by steam usage might also be considered inequitable to the smaller customers.

On page 7 of the Application, Creative Energy states that "a one-year amortization of these costs, for example, would equate to about a 11.5 percent steam rate increase overall in 2020".

On page 49 of the Application, Creative Energy states "that a one-year amortization of these costs, for example, would equate to about a 9 percent steam rate increase overall in 2020".

23.6 Please clarify the overall percentage rate increase in 2020 based on a one-year amortization period of these deferred costs and provide the overall percentage rate increase based on a three-year amortization period. Please provide the calculations in an Excel spreadsheet.

RESPONSE:

Please refer to Attachment 23.6 – DARR Amortization Period. The results are summarized as follows:

Amortization Period	DARR $/M#	DARR 2020 Rate Impact
1 year	**$0.61**	**7.9 %**
2 year **(Reflecting evidentiary Update)**	**$0.40**	**5.3%**
Proposed **(2-year amortization but no change based on Evidentiary Update as explained in the response to BCUC IR 23.11)**	**$0.29**	**3.8%**
3 year	**$0.21**	**2.7%**

23.6.1 Please provide the amount of the DARR ($/M#) if the amortization period was one-year and three-years.

RESPONSE:

Please refer to the response to BCUC IR 23.6.

23.7 In addition to one-year and two-years, what alternative amortization periods, if any, did Creative Energy consider and why were they rejected?

RESPONSE:

Please refer to the response to BCUC IR 23.3.

On page 47 of the Application, Creative Energy provides the following table showing the forecast balance of the non-rate base deferred expenses in the Pension Expense Deferral Account and TPRCDA totals $641,614.

Table 50: Pension Expense and Third-Party Regulatory Costs Deferral Account Balances

Deferred Account Name	2018 Opening Balance	Additions/ (Deductions)	Interest/ AFUDC	Amortization	Ending Balance
Reg. Transitional Adjustment Deferral Account	115,261	-	2,017	(117,278)	-
Pension Expense Deferral Account 2016	(77,509)	-	(1,356)	78,866	-
TPRCDA 2016	(34,739)	-	(618)	35,357	-
Pension Expense Deferral Account 2017	242,034	-	4,236	(246,270)	-
TPRCDA 2017	(113,502)	-	(1,986)	115,488	-
Pension Expense Deferral Account 2018	-	377,966	6,614	-	384,580
TPRCDA 2018	-	207,659	3,634	-	$ 211,293
Subtotal	131,546	585,624	12,540	(133,837)	595,873
TPRCDA 2019					$ 45,741
Total					$ 641,614

Creative Energy also states on page 47, "The amounts recorded and un-recovered through the period ending December 31, 2018 total $595,830, and the total amount to be recovered includes the addition of partial BCUC regulatory costs of $45,741 to review the Beatty-Expo CPCN, which are added to the TPRCDA in 2019 as explained and proposed in section 1.1." [*Emphasis Added*]

On page 2 of the Evidentiary Update, Creative Energy states, "[it] proposes to add an additional amount of $39,499 to the opening balance of the amounts to be recovered through the Deferral Account Rate Rider (DARR); that is, the addition of that amount to the Third-Party Regulatory Costs Deferral Account. However, as discussed below, Creative Energy seeks no change to the level of the DARR of $0.29/M#, as requested for approval in the Application." [Emphasis Added]

23.8 Please confirm, or explain otherwise, that Table 50 should be revised based on the Evidentiary Update such that the TPRCDA 2019 amount in the table is $85,241 (rather than $45,741). If confirmed, please provide an updated Table 50.

RESPONSE:

Confirmed. Please refer to the updated Table 50 Update below.

Table 50 Update: Pension Expense and Third-Party Regulatory Costs Deferral Account Balances

Deferred Account Name	2018 Opening Balance	Additions/ (Deductions)	Interest/ AFUDC	Amortization	Ending Balance
Reg. Transitional Adjustment Deferral Account	115,261	-	2,017	(117,278)	-
Pension Expense Deferral Account 2016	(77,509)	-	(1,356)	78,866	-
TPRCDA 2016	(34,739)	-	(618)	35,357	-
Pension Expense Deferral Account 2017	242,034	-	4,236	(246,270)	-
TPRCDA 2017	(113,502)	-	(1,986)	115,488	-
Pension Expense Deferral Account 2018	-	377,966	6,614	-	384,580
TPRCDA 2018	-	207,659	3,634	-	211,293
Subtotal	131,546	585,624	12,540	(133,837)	595,873
TPRCDA 2019					85,241
Total					681,114

23.9 Please explain why Core Schedule 12 in the Financial Schedules for RRA Filing was not updated in the Evidentiary Update. If applicable, please provide a revised Core Schedule 12 for the proposed further addition of $39,499 to the TPRCDA for 2019.

RESPONSE:

Core Schedule 12 should be updated to report the additional $39,499. This change is the only required material change to the Core RRA 'Schedules' file in respect of Creative Energy's Response to BCUC IR 1. However, Schedule 12 has no impact into any other schedules and, further, Creative Energy has not proposed a change to the level of the DARR for the reasons explained in the response to BCUC 23.11.

To minimize the number of electronic files on the record for ease of cross-referencing, Creative Energy suggests that it would be reasonable to wait until its response to Round 2 IRs in this proceeding to provide an updated file as required based on any further changes or as directed, and/or to otherwise provide the updated file as part of a compliance filing following a Commission decision into the Application as required.

On page 49 of the Application, Creative Energy states, "Going forward, Creative Energy will seek approval to amend the level of the DARR if and as required to recover recorded variances between actual and forecast amounts in subsequent periods."

On page 7 of Appendix 1 to the Evidentiary Update, Creative Energy provided the following table:

Table 53 Update: Forecast DARR Recovery

DARR	0.29	$/M#										
Annual Load		1,140,634	M#									
Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Historical Load Shape	14.3%	12.3%	11.4%	8.6%	6.2%	4.5%	3.7%	3.5%	4.3%	7.2%	10.9%	13.3%
Monthly Load 2020	163,030	139,898	129,547	98,566	70,212	50,960	42,023	39,380	48,710	81,959	124,562	151,787
Opening Balance 2020	681,114	633,787	593,175	555,569	526,955	506,573	491,780	496,793	485,362	471,222	447,429	411,270
Interest							17,212					
Rate Rider Revenue	47,327	40,612	37,607	28,613	20,382	14,793	12,199	11,432	14,140	23,792	36,159	44,063
Ending Balance 2020	633,787	593,175	555,569	526,955	506,573	491,780	496,793	485,362	471,222	447,429	411,270	367,207
Monthly Load 2021	163,030	139,898	129,547	98,566	70,212	50,960	42,023	39,380	48,710	81,959	124,562	151,787
Opening Balance 2021	367,207	319,880	279,269	241,662	213,049	192,667	177,873	171,900	160,468	146,328	122,536	86,376
Interest							6,226					
Rate Rider Revenue	47,327	40,612	37,607	28,613	20,382	14,793	12,199	11,432	14,140	23,792	36,159	44,063
Ending Balance 2021	319,880	279,269	241,662	213,049	192,667	177,873	171,900	160,468	146,328	122,536	86,376	42,313

23.10 Please discuss whether the interest accrued on the Pension Expense Deferral Account 2018, TPRCDA 2018 and TPRCDA 2019 deferral balances up to the time of amortization will also be recovered through the DARR, given that the balances proposed for recovery are through the period ending December 31, 2018 only. If yes, please explain if and how this interest will be recovered.

RESPONSE:

Yes, the balance in the deferral accounts including interest through 2019 will be recovered through the DARR. For the purpose of calculating the DARR. annual interest at Creative Energy's short-term debt rate on the mid-year balance is forecast to be recovered as illustrated in the Table 53 Update.

23.11 Please explain why Creative Energy proposes not to change the level of the DARR of $0.29 per thousand pounds of steam (M#) after the Evidentiary Update given that the full amount of the deferred balances will not be recovered at the end of two years.

RESPONSE:

Creative Energy intends to review the level of the DARR as part of its 2021 RRA to ensure full and ongoing recovery of the balance in the two deferral accounts through the DARR.

Creative Energy proposes that the level of the DARR and the length of amortization period be reviewed on an annual basis, even if a multi-period RRA approval was in place. This approach also reflects that actual billing determinants – i.e. steam load – may vary from approved load. To update the level of the proposed DARR at this point is therefore unnecessary.

23.11.1 Please confirm whether Creative Energy intends to recover the forecast remaining balance of $42,313 at the end of 2021 (i.e. does Creative Energy intend to continue charging the DARR after the proposed two-year recovery period 2020-2021 until the balance is $0?).

RESPONSE:

Creative Energy would intend to recover the entire balance and thus in the circumstance that there is an outstanding balance at the end of 2021 it would seek for the DARR to continue. Please refer to the response to BCUC IR 23.11.

23.12 Please provide the level of the DARR (per thousand pounds of steam) if Creative Energy were to amortize the additional amount of $39,499 over a two-year amortization period as well.

RESPONSE:

The level of the DARR would be $0.40/M#, a rate impact of 5.3%, also as reported in the response to BCUC IR 23.6.

23.13 Please explain what the Historical Load Shape monthly percentages in Table 53 are based on and please provide a breakdown of this load shape (for example, average actual load per month in the past three years).

RESPONSE:

The historical load shape is based on 19 years of load data at the Beatty Steam Plant from 1999-2017. The corresponding average actual monthly load corresponding to the percentage values in Table 53 are provided in the table below.

Month	Average Load	%
Jan.	153,492	14.3%
Feb.	131,321	12.3%
Mar.	121,759	11.4%
Apr.	92,525	8.6%
May.	65,944	6.2%
Jun.	47,896	4.5%
Jul.	39,378	3.7%

Month	Average Load	%
Aug.	36,825	3.5%
Sep.	45,496	4.3%
Oct.	76,792	7.2%
Nov.	116,363	10.9%
Dec.	142,475	13.3%
Totals	1,070,267	100%

Creative Energy notes also that this data on historical load shape supported the determination and compliance filing in the matter of the Commission's recent approval under Order G-226-19 of Creative Energy's fuel cost rate rider for a two-year amortization period.

23.13.1 Please explain the rationale for using this basis to calculate the Historical Load Shape and why this is considered appropriate for calculating the DARR/Rate Rider Revenue.

RESPONSE:

It was Creative Energy's simple preference to forecast the DARR under a model of monthly revenue as it has done so in the past and the analysis can then accommodate if need be an assessment of partial year amortization periods.

Creative Energy acknowledges that for a given annual load forecast and full calendar year amortization period, and assuming interest is applied consistently, the results of both a monthly load forecast and annual load forecast approach for determining the level of the DARR would yield the same result.

C. NORTHEAST FALSE CREEK

24.0 Reference: APPLICATION OVERVIEW
Exhibit B-1-1, pp. 1, 2, 5; Exhibit B-1-1, Evidentiary Update Schedules for RRA Filing, NEFC Schedule 1, 12; Exhibit B-1, Section 1.2.3.1, p. 10
Revenue Deficiency Deferral Account (RDDA)

On page 5 of the Evidentiary Update, Creative Energy states "the updates to the 2019-2020 NEFC RRA result in a proposed addition to the RDDA of $9,064 in 2019, a net increase of $137,183 compared to the Application, and a proposed addition to the RDDA of $441,741 in 2020, a net increase of $62,458 compared to the Application. There is no required change to the proposed 3.7 percent rate increase after accounting and correcting for the items above."

On page 2 of the Evidentiary Update, Creative Energy states that it requests approval to increase the RDDA balance by $9,064 in 2019 and by $441,662 in 2020.

In Line 27 of NEFC Schedule 1 and Line 1 of NEFC Schedule 12 (Row 34) from the Financial Schedules attached to the Evidentiary Update, Creative Energy shows a revenue deficiency of $9,064 for the 2019 Test Year and a corresponding addition of $9,064 in the RDDA for 2019.

Line 1 of NEFC Schedule 12 (Row 48), Creative Energy shows an addition of $751,100 in the RDDA for 2020.

24.1 Please confirm whether the proposed addition to the RDDA in 2020 is $441,662 as stated on page 2 of the Evidentiary Update, $441,741 as stated on page 5 of the Evidentiary Update, or $751,100 as shown in NEFC Schedule 12 (Row 48).

RESPONSE:

The net addition to the RRDA in 2020 is $441,662. This is net of revenue related to the FCAC rate rider. Absent a rate rider of $16.15 per MWh, Creative Energy would apply to add the amount of $751,100 to the RDDA in 2020.

24.1.1 Please provide revised financial schedules for NEFC and errata to the Application or Evidentiary Update, as appropriate.

RESPONSE:

NEFC Schedule 12 does not need to refer to 2020 figures as that is not the purpose of the record provided in that Schedule. Thus, the reporting in Schedule 12, while having no effect, will be corrected in due course when Creative Energy provides an updated 'Schedules' file under the timing as contemplated in the response to BCUC IR 23.9.

The information currently reported in Schedule 1 correctly reflects the update to the NEFC revenue requirements.

24.2 Given the net increase of $62,458 to the 2020 RDDA in the Evidentiary Update compared to the Application, please explain why the proposed rate increase remains at 3.7 percent.

RESPONSE:

The explanation is simply that Creative Energy continues to propose a rate increase of 3.7 percent as reasonable overall as explained in the Application and in response to a number of IRs. The increase is not tied to a specific cost driver that can then be traced through the Evidentiary Update. Rather, in light of the Evidentiary Update, maintaining the NEFC rate increase at 3.7 percent has the effect of increasing the amount of the addition to the RDDA that Creative Energy seeks approval of in 2020.

Please also refer to the responses to BCUC IRs 25.5 and 25.6, for example.

24.2.1 Did Creative Energy consider changing the proposed percentage increase in Hot Water Service Rates in 2020? Please explain why or why not, and provide supporting calculations, if appropriate.

RESPONSE:

Please refer to the responses to BCUC IR 24.2, 25.5 and 25.6.

On page 10 of the Application, Creative Energy states that fuel and steam costs were lower than expected in 2019 because the steam meter at the PARQ Hot Water Plant was "very recently detected to be underreporting steam flow." Creative Energy states it is "addressing this matter prospectively as part

of the 2020 NEFC RRA and an associated increase to the forecast of NEFC steam load and the projected cost of steam sales in 2020."

24.3 In the same format as NEFC Schedule 1, please provide Creative Energy's best estimate of what the revenue requirement and revenue (surplus)/deficiency would have been for the 2019 and 2020 Test Years, respectively, if there was no issue with the steam meter at the PARQ Hot Water Plant.

RESPONSE:

A response to this specific request is provided below, but please refer to the response to BCUC IR 27.4, which explains why it is not applicable to account for the metering issue under the counter-factual presented in the response to this IR. There was and is not under-billing at the approved rates nor related under-recovery of the Creative Energy's cost of service during the period that the meter was underreporting steam consumption. And as explained in the Application and referred to in the response to BCUC IR 12.3, the 2020 revenue requirements and proposed rates address this matter prospectively.

- **If there was no issue with the steam meter at the PARQ Hot Water plant, the costs in Schedule 1 would not change for 2019. A change would occur to Core steam load and, therefore, Core revenues would increase. With an increase to steam revenues, the revenue (surplus) / deficiency would shift from a deficiency to a surplus. It is estimated that the incremental impact in 2019 would have been an additional 30,678 M# of steam internally transferred to NEFC. (Please refer to the response to BCUC IR 27.3.1, which reports actual versus imputed PARQ plant load in 2019, the difference of which equals 30,678 M#).**

- **Assuming an average rate of $7.65, the Core system would have an additional $234,687 revenue ($7.65/M# X 30,687 M#'s). As such, the revenue deficiency of $85,241 in the Evidentiary Update would become a recorded revenue surplus of $149,446 in 2019. As revenue increased, it would also impact the percentage allocated using the Massachusetts formula, but the impact of this change would not be material.**

Line #	Item	2019 Test Year
1	Fuel Expense - Base Cost	n/a
2	Operation & Maintenance Expense	4,934,103
3	Municipal Taxes	268,387
4	Other	
5	Total Operating and Maintenance Expense	5,202,490
6	Property Taxes	663,826
7	Income Tax Expense	279,700
8	Depreciation Expense	976,700
9	Depreciation Expense Allocated to Non Reg	(706)
10	Amortization of CIAC	(31,410)
11	Amortization of Rate Base Deferred Exp.	0
12	Amortization of Non - Rate Base Deferred Exp.	0
13	Actual/Proposed Return on Rate Base	1,609,000
14	**Cost of Services**	**8,699,600**
15		
16	**Total Revenue Requirement**	**8,699,600**
17		
18		
19	Other Income	n/a
20	Steam Sales Revenues	8,849,046
21	**Total Revenues**	**8,849,046**
22		
23	Revenue (Surplus)/Deficiency	(149,446)

24.4 Given that the proposal to maintain NEFC Hot Water Service Rates for 2019 is incorporated in the financial schedules, please discuss whether Creative Energy considered increasing Hot Water Service rates for 2019 to limit the addition to the RDDA. Please explain why or why not.

RESPONSE:

Creative Energy did not consider increasing Hot Water Service rates for 2019 due to the fact it was forecasting a reduction in the RDDA at the current approved rates and with due regard also to the Commission's direction under Order G-167-16 to not begin recovery of the RDDA balance until 2020; in other words, to maintain current-approved rates until 2020.

The background and related factors underpinning this approach are explained in sections 1.2.1 and 1.2.3.1 of the Application.

24.4.1 Please provide with supporting calculations the percentage increase in Hot Water Service rates that would be required if there were no additions to the RDDA in 2019.

RESPONSE:

The Evidentiary Update sets out a forecast increase to the RDDA balance in 2019 of $9,064 and that amount is equivalent to the forecast revenue deficiency at approved 2019 interim rates. This amount is approximately 0.6% of the 2019 NEFC RRA; in other words, hot water rates would need to increase by 0.6% in 2019 in order for there to be no addition to the RDDA in 2019.

On page 1 of the Evidentiary Update, Creative Energy states:

> Beyond the discussion below of each of the changes reflected in this Evidentiary Update, the substantive narrative and variance explanations provided in the Application remain current and no revisions are required in that regard.

24.5 Given that the substantive narrative of the Application Remains current, please explain and provide supporting calculations for how the proposed 3.7 percent increase in NEFC Hot Water Service Rates for 2020 allows Creative Energy to "commence recovery" of the RDDA balance in 2020.

RESPONSE:

Creative Energy intended to convey that the proposed increase in 2020 rates lowers the rate of addition to the RDDA that would otherwise occur absent a rate increase in 2020, which effectively means that some recovery of the RDDA has commenced.

The rate increase of 3.7 percent is forecast to increase hot water service revenues by $56,417 as shown in the response to BCUC IR 28.1. Thus, absent this rate increase, Creative Energy would forecast an incremental addition of $56,417 to the amount of $441,741 that Creative Energy seeks approval to add to the RDDA balance of set out in its Evidentiary Update.

24.5.1 Please provide the amount which Creative Energy proposes to recover from the RDDA in the 2020 Test Year and the basis for that amount.

RESPONSE:

Please refer to the response to BCUC IR 24.5.

25.0 Reference: APPLICATION OVERVIEW
Exhibit B-1, Section 1.2.2, p. 9
NEFC Neighbourhood Development Update

On page 9 of the Application, Creative Energy states:

> The City of Vancouver (the City) has extended their connection bylaw to now include the future development in the NEFC neighbourhood, which means that the City will provide service to the future developments in the NEFC, rather than Creative Energy.
>
> Creative Energy intends to supply the hot water to serve the City's loads in the NEFC as it develops using the installed capacity and capital expansions as contemplated when the rates and RDDA were established for NEFC service. <u>However, the necessary arrangements with the City have not been made yet for Creative [Energy] to serve that load</u> and are subject to the City's process. <u>At this point in time therefore, Creative Energy does not have a consolidated forecast of load growth in the NEFC neighborhood and the timing</u> of the required incremental capacity investments to support that load growth is uncertain. [*Emphasis Added*]

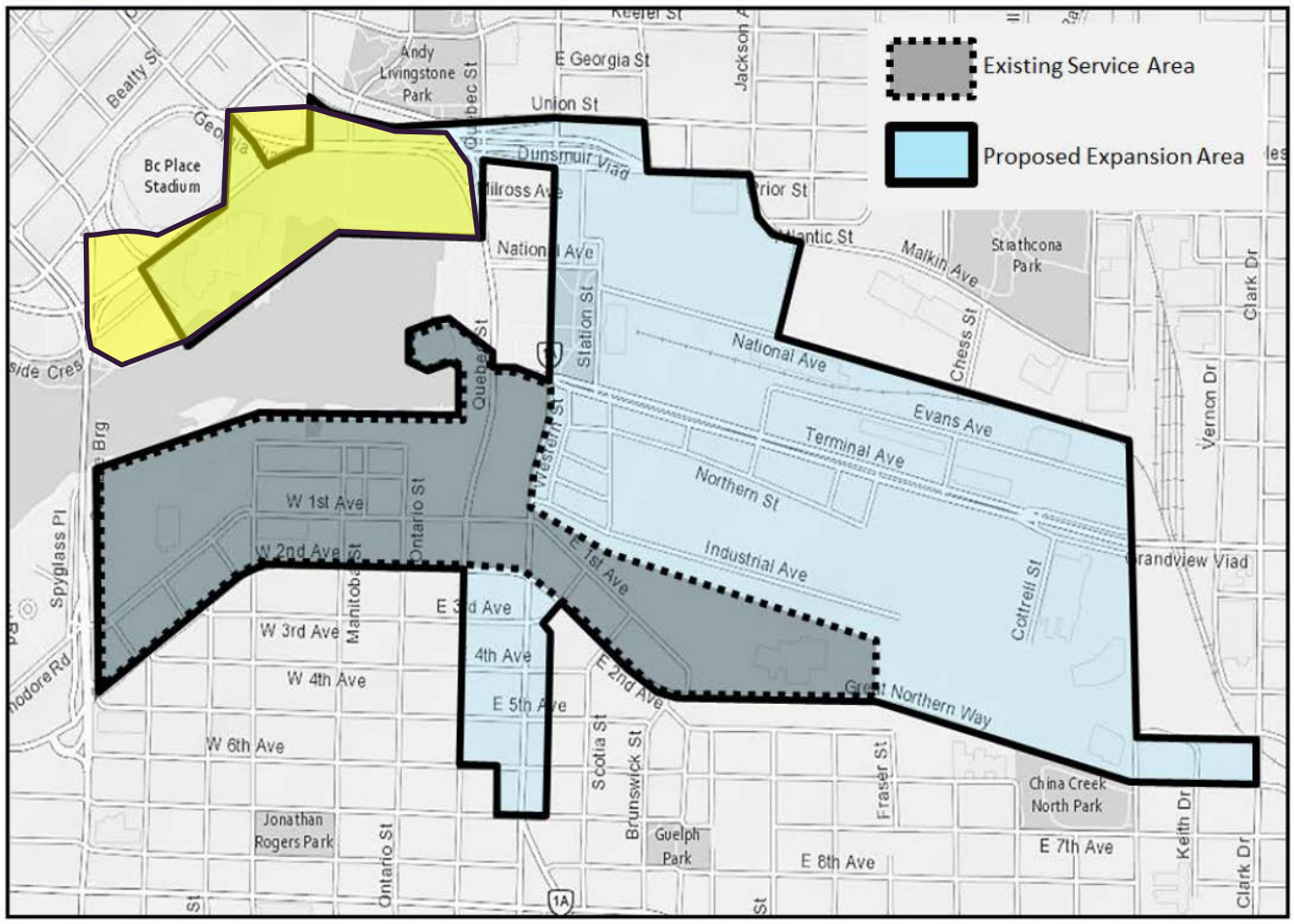
25.1 Please provide a map showing where the City has extended their connection bylaw within the NEFC neighbourhood. On this map, please also include the area of NEFC for which Creative Energy received approval in the full buildout of the hot water system.

RESPONSE:

The map provided below has been extracted from a City of Vancouver report to council titled "Expansion of the False Creek Neighbourhood Energy Utility ("NEU")", dated February 13, 2018. The yellow polygon overlay is by Creative Energy, indicating the approximate location of the NEFC area for which Creative Energy received approval.

Link to report: https://council.vancouver.ca/20180221/documents/pspc3.pdf

FIGURE 1. MAP OF PROPOSED EXPANSION AREAS



25.2 Please provide an update on the status of discussions with the City, including an estimated timeline for when the arrangements may be finalized.

RESPONSE:

Discussions with the City have continued in the time since this Application was filed, but the City has not provided any clarity on timeline going forward to finalize arrangements. As estimate would have to encompass a large range, therefore we suggest between 6 and 24 months.

25.2.1 Is Creative Energy aware of any risks that would cause an agreement with the City to not be finalized or to be finalized under different terms than what is currently contemplated by Creative Energy (i.e. that Creative Energy will supply the hot water to serve the City's loads in the NEFC using the installed capacity and capital

expansions as contemplated when the rates and RDDA were established for NEFC service)? Please discuss.

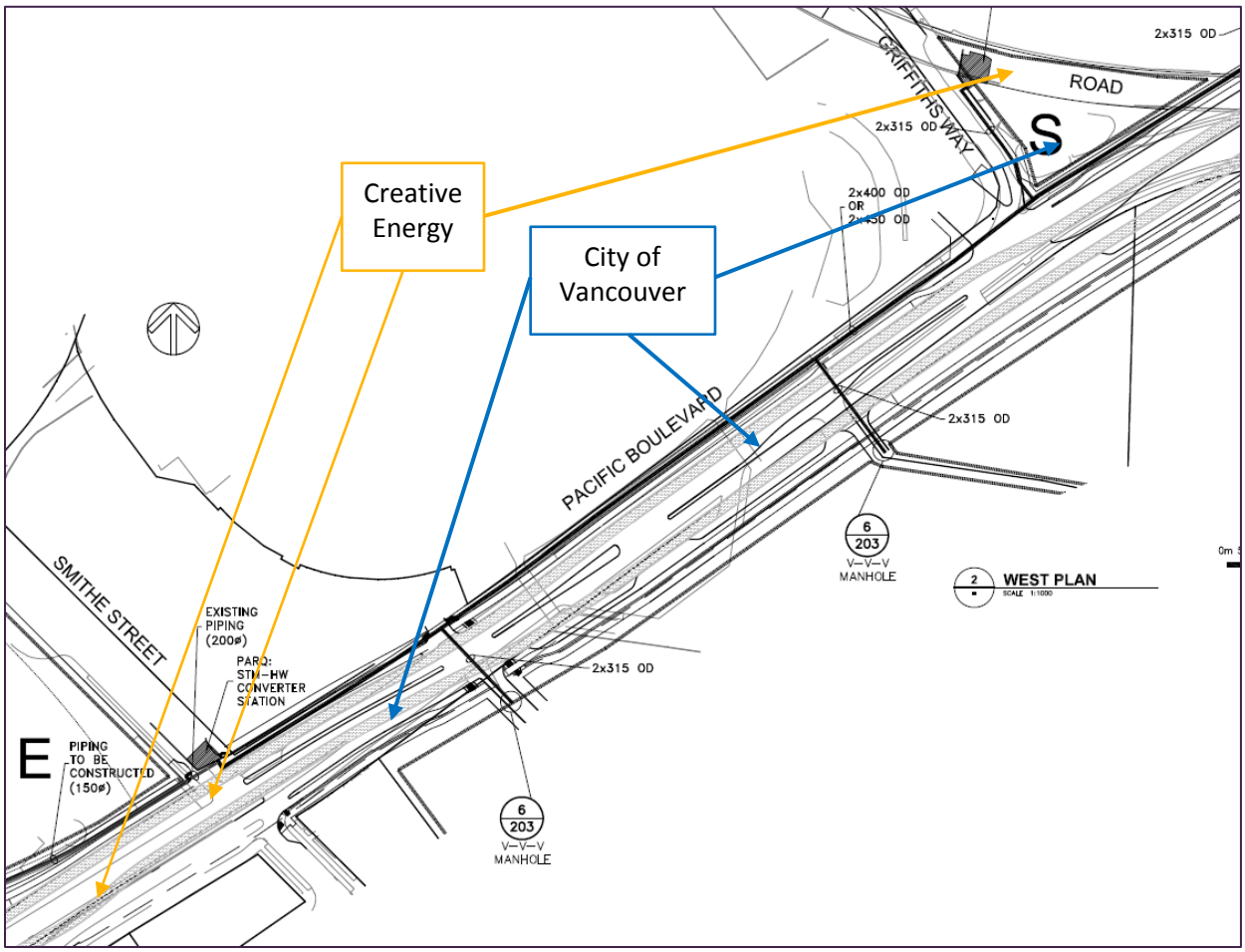
RESPONSE:

Broadly the requirements of the City of Vancouver are for a provider to supply a schedule of thermal energy, specified in peak MW and annual MWh, increasing year-by-year, from the provider's own facility. Creative Energy is the only existing thermal generating facility of sufficient size to serve NEFC and discussions with the City are ongoing as to how Creative Energy can meet NEFC demand growth.

25.3 Please provide a diagram to demonstrate how Creative Energy intends to supply hot water to serve the City's loads in the NEFC. Please clearly differentiate between the hot water system infrastructure that is owned and operated by the City and the hot water system infrastructure that is owned and operated by Creative Energy.

RESPONSE:

Please refer to the diagram provided below. Essentially, Creative Energy will own the Steam to Hot Water convertor stations entirely, and the existing hot water piping and energy transfer stations which provide service to the existing NEFC customers, and the City of Vancouver will own the piping and energy transfer stations to serve new NEFC customers.



On page 9 of the Application, Creative Energy also states:

> As a result, Creative Energy believes that at this time there is not a sufficient basis to determine longer-term levelized increases to NEFC rates given the uncertainty in relation to load growth. In its next RRA and as applicable following confirmation with the City of a long-term plan for connecting new load in the NEFC, Creative Energy will renew a long-term plan of projected levelized rates that recover the RDDA over a reasonable time frame. In the absence of such a consolidated basis on which to determine current rates within a longer-term plan for RDDA recovery, Creative Energy sets out below its 2019 and 2020 revenue requirements for the NEFC with a plan to commence recovery of the RDDA balance in 2020 through a modest increase in rates.

25.4 Given the current status of discussions with the City, does Creative Energy still expect full buildout of the NEFC system by 2025?

RESPONSE:

No. Specifically, the lands owned by Concord Pacific are not expected to be fully built out by 2025, which is a delay in the full buildout date. The other developments are generally on track.

25.4.1 Please discuss if Creative Energy has completed any scenario analysis with regards to the load growth, including a discussion of each of the scenarios reviewed.

RESPONSE:

As described in section 1.2.3.2 of the Application Creative Energy assessed a scenario of the bound of necessary rate increases under a levelized approach that would clear the RDDA balance in 10 years, by 2030 as contemplated under Order G-167-16, by assuming no load growth over that period. The result was a rate increase of 5 percent per year over that time frame to existing customers. No other scenarios around load growth have been analysed at this time.

Please refer also to the response to CEC IR 4.2.

25.5 Given the uncertainty in relation to load growth, did Creative Energy consider maintaining the current approved rates until a longer-term plan is in place? Please discuss why or why not.

RESPONSE:

Creative Energy considered that a modest increase in rates to NEFC customers was reasonable in response to steam, fuel and operating cost pressures in addition to considering it prudent to avoid a larger addition to the RDDA balance otherwise in 2020. Please refer to section 1.2.3.2 of the Application.

25.6 Please confirm if Creative Energy will be submitting a new rate application once a long-term plan is in place for NEFC and if so, the expected timing of that filing.

RESPONSE:

Creative Energy plans to submit its 2021 RRA later this year in advance of the 2021 test period and that application will be informed by and will report and update on the specific circumstances in effect or anticipated at the time. Creative Energy considers that the preamble reference to this question

continues to reflect Creative Energy's general intent going forward:

> ***In its next RRA and as applicable following confirmation with the City of a long-term plan for connecting new load in the NEFC, Creative Energy will renew a long-term plan of projected levelized rates that recover the RDDA over a reasonable time frame.***

26.0 Reference: APPLICATION OVERVIEW
Exhibit B-1, Section 1.2.2, p. 9; Creative Energy Application for a Certificate of Public Convenience and Necessity for a Low Carbon Neighbourhood Energy System for Northeast False Creek and Chinatown Neighborhoods of Vancouver (2015 Creative Energy NEFC CPCN), Exhibit B-1, Section 5.1, p. 58
2020 Test Year Hot Water Demand

On page 9 of the Application, Creative Energy states:

> The hot water load forecast that formed the basis of the Creative Energy's NEFC CPCN Application in 2015 and its NEFC RRA in 2016 assumed full buildout in the NEFC neighbourhood on 8 parcels of land by 2025 with a total connected floor area of 506,300 square meters and total hot water demand of 48,100 MWh.
>
> Presently, Creative Energy has connected a total of four buildings in the NEFC, served by two hot water plants, with a total connected floor area of 162,481 m^2 and hot water demand of 19,162 MWh.

26.1 Please provide the Energy Usage Intensity (EUI) factors used to determine the NEFC 2020 hot water demand of 19,162 MWh (in kWh/m^2).

RESPONSE:

As explained in section 4.1.2 on page 43 of the Application the forecast 2020 hot water demand of 19,16 MWH is forecast based on:

1. **The average of 2018 and 2019 consumption in MWh for existing customers, reflecting the limited data set available given that service to the NEFC commenced in April 2017, plus**

2. **The addition of a new customer (ARC building), for which a full year's load in 2020 is scaled on the basis of its floor area compared to that of One Pacific, an existing, similar building customer in terms of scale and use.**

Creative Energy did not use an estimate of EUI as the basis of this forecast. The imputed EUI based on the total connected floor area of 162,481 m2 and 2020 hot water demand of 19,162 MWh is 117 kWh/m2, which is not an unexpected result given that the actual MWh load at the PARQ casino has been higher than initially forecast based on the EUI of 95 kWh/m2 that supported the CPCN application.

26.2 Please provide the NEFC 2020 forecast load and connected floor area provided in the 2016 NEFC RRA. Please reconcile any differences between this previous NEFC 2020 forecast and the NEFC 2020 forecast proposed in this Application.

RESPONSE:

As noted in the preamble to this IR and in the response to BCUC IR 26.1, there are four buildings now connected in the NEFC in 2020, with a total connected floor area of 162,481 m2 and forecast hot water demand of 19,162 MWh. This buildout is lower than expected, which explains why it is lower than the amount reported as the 2020 forecast as provided in the 2016 NEFC RRA (31,555 MWh at 332,280 m2 of connected floor area, as provided in Table 2 of that application).

In Exhibit B-1 of the 2015 Creative Energy NEFC CPCN, Creative Energy stated the Energy Usage Intensity (EUI) is 95 kWh/m^2 for both commercial and residential buildings.

26.3 Please confirm the EUI factor used to inform the NEFC 2020 hot water demand forecast. Please explain and justify the EUI factor used to inform the NEFC 2020 hot water demand forecast.

RESPONSE:

Please refer to the response to BCUC IR 26.1. Creative Energy did not use an estimate of EUI as the basis of this forecast.

27.0 Reference: APPLICATION OVERVIEW
Exhibit B-1, Sections 1.2.3.1, p. 10; Exhibit B-1-1, Evidentiary Update Schedules for RRA Filing, NEFC Schedule 1, 15A; Creative Energy 2016-2017 RRA Decision, p. 17
PARQ Hot Water Plant Steam Meter

On page 10 of the Application, Creative Energy states:

> The steam meter at the PARQ Hot Water Plant was very recently detected to be underreporting steam flow. The effect was to reduce the total revenue requirement below the revenues projected based on MWh hot water load. Creative Energy is addressing this matter prospectively as part of the 2020 NEFC RRA and an associated increase to the forecast of NEFC steam load and the projected cost of steam sales in 2020.

In NEFC Schedule 1 from the Financial Schedules attached to the Evidentiary Update, Creative Energy provides the following cost of steam sales forecast:

	2019	2020
Item	**Test Year**	**Test Year**
Fuel	550,767	1,061,666
Steam Tariff	257,991	536,051
Cost of Sales	**808,758**	**1,597,717**

In NEFC Schedule 15A from the Financial Schedules attached to the Evidentiary Update, Creative Energy provides the following NEFC steam load forecast:

			Total
2019 Projected			
NEFC Total COST OF ENERGY - STEAM RATES			
	Actual Consumption M#		33,947
2020 Projected			
NEFC COST OF ENERGY - STEAM RATES			
	Estimated Consumption M#		70,309

27.1 Please confirm, to the extent possible, how long the PARQ Hot Water Plant steam meter has been underreporting steam flow (e.g. month and year).

RESPONSE:

Creative Energy estimates that the PARQ plant condensate meter has likely been underreporting since January 2018.

27.2 Please confirm whether the PARQ Hot Water Plant steam meter has now been fixed.

RESPONSE:

The PARQ condensate meter has been repaired and transmitter electronics to the meter have been replaced, and the BTU meters are now having their programming confirmed to be operating within manufacturer tolerances.

27.2.1 If confirmed, please provide the following:

- When (e.g. month and year) the meter was fixed;
- A breakdown of the meter repair cost into capital and operating expenses;
- The total volume (M#) of underreported steam use;
- Whether the meter repair costs are a cost of the Core Steam System or NEFC and where the costs are recorded (i.e. what line item(s)); and
- Whether Creative Energy conducted any examination of its other steam meters for similar issues during the process of rectifying the PARQ Hot Water Plant steam meter issue. If yes, please discuss the results of Creative Energy's examination, including, but not limited to, whether any other meters need or needed to be fixed, and the cost of repairs. If not, please explain why not.

The new electronic transmitter was installed on December 18, 2019. The cost for the new transmitter electronics and installation was $3,683. All costs for repair were charged to operating expenses for the Core steam system.

Creative Energy has not examined its other condensate meters for similar issues during the process of rectifying the PARQ meter issue. Every month Creative Energy reviews all steam customers monthly consumption and compares the current monthly consumption to the previous month and to the historical use of each building, year over year going back 10 years. The PARQ plant steam meter had not been included in this process as there was very limited historical data with which to analyze trends and data consistency.

Please refer to the response to BCUC IR 27.3.1 for a summary of actual versus imputed steam load.

27.2.2 If not confirmed, please provide Creative Energy's capital plan (e.g. cost and timeline) for fixing the PARQ Hot Water Plant steam meter and who (and what proportion) will bear the cost (e.g. Core Steam System, NEFC).

RESPONSE:

Not applicable. Please refer to the response to BCUC IR 27.2.1.

27.3 Please confirm, or explain otherwise, whether Creative Energy has adjusted its 2019 steam load and cost of steam sales (as shown in NEFC Schedules 1 and 15A) as a result of the PARQ Hot Water Plant meter underreporting steam flow and explain how the amount of the adjustment was determined.

RESPONSE:

The 2019 NEFC RRA is based on actual recorded steam transfers to the Core, which for the reasons discussed in section 1.2.3.1 of the Application, reduced the total revenue requirement below the revenues projected based on MWh hot water load. Creative Energy has addressed this matter prospectively as part of the 2020 NEFC RRA by incorporating an increase to the forecast of NEFC steam load and the projected cost of steam sales in 2020 using the methodology set out in section 4.1.2 of the Application.

As described in section 4.1.2, the methodology to address this matter prospectively in 2020 is to forecast the steam load transfer that supports the NEFC System on the basis of estimated hot water consumption in MWh, scaled up based on the measured efficiency of the distribution system and the efficiencies of the PARQ Hot Water Plant and the Aquilini Center Hot Water Plant. Thus, the forecast is based on the hot water meter, not the steam meter. Please refer also to the response to BCUC IR 27.3.1.

27.3.1 Please provide the Actual 2019 NEFC monthly hot water load (MWh) and supporting calculations for converting into thousand pounds of steam.

RESPONSE:

Actual 2019 NEFC monthly hot water load (MWh) and Actual metered 2019 NEFC load is provided in t the tables below, based on including actual load for the months of October – December as an update to the projected amounts provided in Table 45 of the Application.

The 2019 imputed steam load for the PARQ Plant reported in the last table is derived by dividing PARQ hot water load by its estimated Plant and Distribution efficiencies (91% and 94%, respectively) and converting to M# by multiplying by a 3.14 conversion factor.

The difference between actual metered PARQ plant steam load and the expected amount based on observed system efficiencies is 30,678 M#.

2019 Actual NEFC Hot Water Load

MWh	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Aquilini Plant Total	300	109	162	122	84	71	57	58	74	136	159	190	1,522
PARQ Plant Total	1,960	2,790	1,919	1,219	633	432	267	287	524	1,789	1,802	2,538	16,161
Total	2,260	2,899	2,081	1,341	717	503	324	345	598	1,925	1,961	2,729	17,683

2019 Actual NEFC Steam Load

Actual M#	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Aquilini Plant Total	653	740	597	452	318	251	184	183	244	469	524	688	5,303
PARQ Plant Total	2,681	5,264	4,534	3,581	1,959	1,229	447	240	318	1,639	2,056	4,697	28,645
Total	3,334	6,004	5,131	4,033	2,277	1,480	631	423	562	2,108	2,579	5,385	33,947

2019 Imputed PARQ Steam Load

Imputed M#	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
PARQ Plant Total	7,195	10,242	7,044	4,475	2,324	1,586	980	1,054	1,923	6,569	6,616	9,317	59,323

Section 11 of the Creative Energy NEFC Customer Service Agreement sets out the terms and conditions between Creative Energy and customers with respect to Back-Billing. Section 11.2 states:

> 11.2 Back-billing means the re-billing by the Utility for Energy Services rendered to a Customer because the original billings were discovered to be either too high (over-billed) <u>or too low (under-billed)</u>. The discovery may be made by either the Customer or the Utility. The cause of the billing error may include any of the following non-exhaustive reasons or combination thereof:
>
> … (c) inaccurate Meter… [*Emphasis Added*]

Section 11.7 of the Creative Energy NEFC Customer Service Agreement states:

> 11.7 Subject to paragraph 12.11 below, in every case of under-billing, the Utility will back-bill the Customer for the shorter of:
>
> (a) the duration of the error; or
> (b) six months prior to the discovery of the error.

On page 17 of the Creative Energy 2016-2017 RRA Decision, the BCUC approved the treatment of NEFC as a Core Steam Service customer charged on the basis of Steam Rates.

27.4 Please explain how Creative Energy has applied the Back-billing provisions stipulated in the Creative Energy NEFC Customer Service Agreement between NEFC and the Core Steam System. Please include, at minimum, the following:

- The total amount of the under-billing in 2019 (and if applicable, 2020);
- Whether revenues in 2019 and 2020 Test Years in the Core Steam System revenue requirement include the under-billed amount(s) to NEFC, and if not, why not;
- Whether the Steam Tariff expense in 2019 and 2020 Test Years in the NEFC revenue requirement includes the under-billed amount(s) owing to the Core Steam System, and if not, why not.
- In the event that the PARQ Hot Water Plant steam meter has been underreporting steam flow for more than six months, how the amount of the under-billing that cannot be back-billed will be treated. For example, will it be treated as a shareholder cost or borne by ratepayers?

RESPONSE:

The back-billing provisions in the NEFC Customer Service Agreement are applicable to the billing of domestic hot water use and not steam. The steam tariff is applicable to the NEFC in respect of its use of steam as a customer of the Core system, and the back-billing provisions in the steam tariff are similar.

In any case, the back-billing provisions should not be applied to back-bill the NEFC system under the circumstances because:

- **2018 rates were set on the basis of an approved load forecast and determinative of the recovery of the 2018 revenue requirements during that period; and**

- **2019 revenue requirements and the proposal to maintain the average rate at the 2018 approved levels are based on actual steam load, which incorporates the effect of the lower metered steam consumption at the PARQ plant.**

Thus, there was and is not under-billing at approved rates nor related under-recovery of the Creative Energy's cost of service during the period that the meter was underreporting steam consumption. And as explained in the Application and referred to in the response to BCUC IR 12.3, the 2020 revenue requirements and proposed rates address this matter prospectively.

28.0 Reference: APPLICATION OVERVIEW
Exhibit B-1, Section 1.2.3.2, p. 11
2020 Proposed Rate Increase

On page 11 of the Application, Creative Energy states:

> The rate increase of 3.7 percent is estimated as a reasonable minimum required increase based on an indicative estimate of inflation of 2 percent per year in steam, fuel and operating costs and continued recovery of and on the infrastructure capital invested and that which would target recovery of the RDDA in 15 to 20 years all else equal. In the alternative, a determination of the necessary rate increases under a levelized approach to clear the RDDA balance in 10 years by 2030, as contemplated under Order G-167-16, may not be reasonable at this time due to current uncertainty of load growth in the NEFC neighborhood and an expected rate increase of 5 percent per year over that time frame to existing customers assuming no load growth.

28.1 Please provide the average-expected combined incremental bill impact for NEFC customers of the proposed 3.7 percent rate increase and the NEFC FCAC Rate Rider in 2020.

RESPONSE:

The average expected bill impact of the proposed rate increase for NEFC is 3.7 percent and the average expected bill impact of the NEFC Rate Rider in 2020 is 20 percent. The average expected combined impact is 23.7 percent. The table below sets out the computation.

Creative Energy notes that the 20 percent expected bill impact to NEFC is approximately the same expected bill impact for Core Steam customers under the $4.40/M# FCAC Rate Rider currently in effect. That result is demonstrated in Table 10 of the Application for the years 2019 and 2020. The rate of $4.40/M# is about 20% and 23% of the incremental total of the other applicable rates for 2019 and 2020, respectively.

		Average expected Bill impact	Calculation
1. Forecast 2020 Revenue at 2020 load forecast and 3.7 % rate increase	**1,581,195**		
2. Forecast 2020 Revenue at 2020 load forecast and no rate increase	**1,524,779**		
3. Revenue Difference	**56,417**	**3.7%**	**= [(1)-(2)] / (2)**
4. Forecast FCAC Rate Rider 2020 Revenue	**309,359**	**20%**	**= (4) / (2)**

28.2 Please explain why Creative Energy did not apply for a 5 percent increase in Hot Water Service Rates in order to clear the RDDA balance by 2030.

RESPONSE:

The RDDA is in place to address the net income impacts of timing differences between the installation of the required infrastructure to serve hot water load and the buildout of customer load over time. The RDDA also allows for a levelized rate structure to smooth rate increases over time recognizing that the rates will not initially recover revenue requirements. Approved forecast revenue shortfalls during initial years of service are added to the balance of the RDDA to be ultimately recovered through load growth and levelized rate increases over time.

Creative Energy does not have a consolidated forecast of load growth in the NEFC neighbourhood and the timing of the required incremental capacity investments to support that load growth is uncertain, as discussed in section 1.2.2 of the Application. Creative Energy therefore considers it premature at this time to advance a comprehensive proposal for full recovery of the RDDA by 2030. Please refer to the responses to BCUC IRs 25.5 and 25.6.

28.3 Please discuss if Creative Energy considered any other rate adjustment mechanism (e.g. inflation only) and discuss the pros and cons of each alternative considered.

RESPONSE:

Creative Energy did not consider any other rate adjustment mechanism.

28.3.1 Please discuss if Creative Energy has completed any scenario analysis with regards to load growth at NEFC, including a discussion of each of the scenarios reviewed.

RESPONSE:

Creative Energy did not conduct a scenario analysis with regards to the load growth to support the 2020 test year RRA. Please refer to the responses to BCUC IR series 25 for an update on the discussions with the City.

28.4 Please explain if Creative Energy completed a benchmarking analysis to compare the applied-for rates with other utilities.

RESPONSE:

Creative Energy did not complete a benchmarking analysis to compare the applied-for rates with other utilities. Creative Energy would question the value of such an analysis for assessing individual utility cost of service within a utility revenue requirements application given the context dependencies in underlying cost drivers and any differences in rate designs, to say nothing of not having a full line of sight into those factors for any utility possibly reviewed.

In Creative Energy's view, benchmark rates may be appropriate in certain circumstances when comparing project alternatives and their relative competitiveness for customers seeking service in comparison to available alternatives.

28.4.1 If yes, please provide the benchmarking analysis. If not, please explain why such an analysis was not completed.

RESPONSE:

Please refer to the response to BCUC IR 28.4.

29.0 Reference: APPLICATION OVERVIEW
Exhibit B-1, Section 1.2.1, 1.2.3.3, pp. 7, 12
Fuel Cost Adjustment Charge (FCAC) Rate Rider

On page 12 of the Application, Creative Energy states:

> Absent a direct charge of an equivalent FCAC Rate Rider to NEFC customers in 2020, the total forecast cost associated with the FCAC Rate Rider will be included in the NEFC total forecast cost of fuel and thus the net effect of the levelized rates currently in place for NEFC customers would be under-recovery of these fuel costs over the 24-month period the Commission determined as appropriate in its Order G-226-19 Decision. Therefore, consistent with the intent of the FCAC Rate Rider, Creative Energy believes that the amount of FCAC Rate Rider revenue to be included in the 2020 NEFC revenue requirement should be directly recovered from NEFC customers in 2020 by way of a rate rider and it is appropriate therefore to not include those amounts in the RDDA for future recovery. This approach also maintains consistency with the approved intent and mechanism of the RDDA as a rate smoothing account for a separate and different purpose as described in section 1.2.1.

On page 7 of the Application, Creative Energy states:

> The RDDA allows for a levelized rate structure to smooth rate increases over time recognizing that the rates will not initially recover forecast revenue requirements.

29.1 Please explain why the NEFC FCAC Rate Rider amount should be treated differently than the FCAC, which is a comparable item that makes up part of the revenue requirements for NEFC.

RESPONSE:

By Order G-226-19, the Commission established that Creative Energy should recover from its Core steam customers the extraordinary fuel costs Creative Energy incurred in the Winter 2018/2019 through the FCAC Rate Rider over a two-year amortization period. In the proceeding that resulted in Order G-226-19, the Commission considered alternative rate mechanisms and alternative amortization periods, for example, and decided that the public interest is best served through the recovery of these costs by a rate rider over a two-year amortization period.

In accordance with Order G-226-19, the FCAC Rate Rider is being applied to the NEFC system which is treated like a customer of the Core Steam system. The present Application seeks approval, and the BCUC has granted interim approval, for Creative Energy to also apply the FCAC Rate Rider to customers taking hot water service from the NEFC system. In the absence of applying the FCAC Rate Rider directly to NEFC customers, the FCAC Rate Rider amount charged to the NEFC system as a customer of the Core steam system will be added to the RDDA increasing the balance to be recovered from NEFC customers in the future instead. Please also refer to the response to CEC IR 5.1.

Creative Energy has also contemplated the general issue raised by this information request in the discussion on page 9 of the Application. Creative Energy submits that in principle, fuel costs should be treated as a flow-through expense to current customers for service received, whether the customer is connected to the Core Steam system or the NEFC system. That is, the FCAC costs also should not be added to the RDDA balance to smooth the NEFC rate impact, which has the effect of inappropriately deferring these current costs for future recovery.

For ease of reference, at page 9 of the Application Creative Energy notes that it intends to review the NEFC rate design in regard to the mechanism by which forecast fuel and steam input costs to serve current NEFC customers in the current period ought to be recovered in comparison to the current approach that adds amounts to the RDDA rate smoothing deferral account for future recovery. Creative Energy's intention is to bring forward such matters in a separate filing, or as part of its next RRA for example.

29.1.1 Please explain specifically how the intent of the RDDA is different than that of the FCAC Rate Rider.

RESPONSE:

The intent of the RDDA is to allow a levelized rate structure that smooths rate increases over time. The rates are initially insufficient to recover forecast revenue requirements. The deficiency is added to the RDDA for future recovery with the buildout of customer load over time.

The intent of the FCAC Rate Rider is not to allow a levelized rate structure aligned to the buildout of load over time, but to recover over a reasonable time frame the extraordinary fuel costs incurred for service already provided to current customers.

29.2 Please explain whether Creative Energy considered increasing the delivery rate proportionate to the FCAC Rate Rider instead of the proposed direct charge or flowing the deficit balance into the RDDA. Why or why?

RESPONSE:

The only alternatives considered were the status quo and the request for approval to apply the FCAC

Rate Rider directly to NEFC system customers. As discussed in the response to BCUC IR 29.1, the Commission just recently considered alternative rate mechanisms and alternative amortization periods, for example, and decided that the public interest is best served through the recovery of the excess fuel costs incurred in Winter 2018/2019 by a rate rider over a two-year amortization period. Creative Energy considers that the determinations of the BCUC in its Order G-226-19 decision are directly applicable.

29.2.1 Please provide a comparison of the pros and cons for the following three approaches:

- Establishing the direct FCAC Rate Rider charge as proposed in the Application;
- Increasing the delivery rate by the corresponding FCAC Rate Rider amount; or
- Maintaining the proposed delivery rate and adding the amount to be recovered through the FCAC Rate Rider to the RDDA.

RESPONSE:

Please refer to the responses to BCUC IRs 29.1, 29.1.1, 29.2 and 28.1. In particular, the approaches suggested by the second and third bullets in this question do not accord with the BCUC's determinations in the Order G-226-19 decision.

29.3 Please confirm, or explain otherwise, that under the proposed direct charge approach, the cost of the FCAC Rate Rider to NEFC would be treated differently for the 2019 Test Year compared with the 2020 Test Year (i.e. it is included in the cost of steam sales in the 2019 Test Year but excluded in the 2020 Test Year).

RESPONSE:

Confirmed. The FCAC Rate Rider was approved effective March 1, 2019 and since then has been applied to the NEFC system which is treated like a customer of the Core Steam system. The approach to directly charge the FCAC Rate Rider to NEFC customers, as proposed in the Application and as approved on an interim basis, is effective January 1, 2020.

29.3.1 If confirmed, please explain what impact, if any, the differing approaches has on the revenue requirements and the requested rates for 2019 and 2020.

RESPONSE:

There is no impact on the requested NEFC hot water rates in either 2019 or 2020.

The impact in 2020 of the implementation of the direct charging of the FCAC Rate Rider to NEFC customers is a reduction of $309,360 to the amount that would otherwise be proposed to be added to the RDDA, as reported in Table 5 of the Evidentiary Update.

There is no impact in 2019 on the proposed amount to be added to the RDDA as the direct charging of the FCAC Rate Rider to NEFC customers is effective January 1, 2020.

On page 12 of the Application, Creative Energy calculates an FCAC Rate Rider equivalent for NEFC customers of $16.15/MWh based on the following calculation:

$$\frac{\text{FCAC Rate Rider \$4.40/M\# * 2020 forecast NEFC steam load transfer 70,309 M\#}}{\text{2020 Forecast hot water load of 19,162 MWh}}$$

29.4 Please confirm, or explain otherwise, that any difference between Actual and 2020 forecast hot water load, and Actual and 2020 steam load transfer, related to the calculation of the FCAC Rate Rider equivalent will be collected or refunded to customers through the Variance Deferral Account.

RESPONSE:

Not confirmed. Creative Energy tracks the actual amounts recovered through the FCAC Rate Rider and accordingly draws down the actual balance in the Fuel Cost Stabilization Account (FCSA). Creative Energy reports quarterly to the Commission on the balance in the FCSA relative to the approved 24-month amortization period to ensure that actual recovery is tracking to forecast. If necessary, Creative Energy could propose an adjustment to the level of the FCAC Rate Rider through a quarterly report if the forecast timing for full recovery of the excess balance in the FCSA was to vary from the approved 24-month amortization period.

Please also refer to the responses to BCUC IR 29.1 and CEC IR 5.1.

29.4.1 If not confirmed, please explain how Creative Energy plans to treat the difference between actual revenues collected and forecast revenues resulting from load forecast variances.

RESPONSE:

Please refer to the response to BCUC IR 29.4.

30.0 Reference: DRAFT ORDER
Exhibit B-1, Appendix B-6
2020 Tariff Page for Permanent Approval

In Appendix B-6 of the Application, Creative Energy provides a draft NEFC Tariff and proposes the following language in reference to the Fuel Cost Adjustment Charge Rate Rider, "Approved as per Order G-xxx-20 and in effect through February 2021, in accordance with Order G-226-19."

In Creative Energy's Fuel Cost Adjustment Charge and FCAC Rate Rider – Compliance Filing dated October 11, 2019 , Creative Energy states, "The updated FCAC Rate Rider is projected to reduce the excess balance in the [Fuel Cost Stabilization Account] to 5 percent of $11,746,911 in 24 months, by the end of February 2021."

30.1 Please explain whether the proposed NEFC FCAC Rate Rider will be in effect through February 2021 or until the Fuel Cost Stabilization Account balance is reduced to the 5 percent threshold.

RESPONSE:

In accordance with Order G-226-19, the approved FCAC Rate Rider to steam customers is effective March 1, 2019. At this time, actual recovery of the balance in the FCSA is tracking close to forecast as

Creative Energy has reported to the Commission outside of this proceeding. As approved and directed the level of the FCAC Rate Rider is expected to reduce the balance in the FCSA to the 5 percent threshold over 24 months by February 2021. Please refer to the response to BCUC IR 29.4.

As explained in the responses to CEC IR 5.1 and BCUC IR 29.1, the application of the FCAC Rate Rider directly to NEFC customers recovers revenue that offsets costs that otherwise would be added to the RDDA and therefore the effect of this direct charging does not reduce the FCSA balance. At this point in time the proposed direct charging of the current FCAC Rate Rider to NEFC customers is expected to also remain in effect until the balance in the FCSA is reduced to the 5 percent threshold.

As part of the contemplated NEFC rate design application, Creative Energy will review a proposal for advancing the recovery of the amounts of FCAC Rate Rider costs that were recorded to the RDDA during the period of March 2019 – December 2019.

30.1.1 Please explain, in Creative Energy's view, if the proposed wording in the draft NEFC Tariff is consistent with the effective time period of the FCAD Rate Rider identified above.

RESPONSE:

Creative Energy confirms that the wording is consistent.

31.0 Reference: NEFC REVENUE REQUIREMENTS
Exhibit B-1-1, Evidentiary Update Schedules for RRA Filing, NEFC Schedule 14; Exhibit B-1, Section 4.2.3.2, p. 46; Creative Energy 2018-2022 Revenue Requirements Application Decision and Order G-205-18 dated October 25, 2018 (Creative Energy 2018-2022 RRA Decision), pp. 34–35
O&M Expense

NEFC Schedule 14 from the Financial Schedules attached to the Evidentiary Update provides a breakdown of NEFC's O&M expenses for 2017 and 2018 Actual, and 2019 and 2020 Test Year.

31.1 In the same format as NEFC Schedule 14, please provide the 2017 Approved amounts for all expenses.

RESPONSE:

Please refer to the table below.

Line #	Acct. #	Account Name	2017 APPROVED
1		**Steam Production-Operation**	
2	500	Supervision and Labour	
3	502	Steam Expenses	536,700
4		**Total Steam Production-Operation**	**536,700**
5			
6		**Steam Production-Maintenance**	
7	506	Structures and Improvements	16,100
8	512	Steam Production Equipment	
9		**Total Steam Production-Maintenance**	**16,100**
10			
11		**Distribution Expenses-Operation**	
12	870	Supervision & Labour	16,100
13	874	Mains & Services	4,200
14	878	Removing & Resetting Meters	
15	880	Other Distribution Operation	15,300
16	933	Transportation	
17		**Total Distribution Expenses-Operation**	**35,600**
18			
19		**Distribution Expenses - Maintenance**	
20	885	Supervision & Labour	
21	886	Structures & Improvements	
22	887	Mains & Services	
23	889	Meters & House Regulators	
24	894	Other Distribution Maintenance	
25		**Total Distribution Expenses-Maintenance**	**0**
26			
27		**Customer Accounts Expenses-Operation**	
28	901	Supervision	
29	902	Meter Reading & Billing Delivery	
30	903	Customer Records & Collection Exp	
31	904	Uncollectible Accounts	
32		**Total Customer Accounts Exp-Operation**	**0**
33			
34		**Sales Promotion Expenses-Operation**	
35	910	Sales Expense	15,700
36	911	Advertising	
37		**Total Sales Promotion Exp - Operation**	**15,700**
38			
39		**Administrative & General - Operation**	
40	915	Directors Fees	8,000
41	920	Admin & General Salaries	6,000
42	921	Office Supplies & Exp	9,200
43	922	Admin & General Exp	
44	923	Special Services	6,100
45	924	Insurance	16,500
46	925	Injuries & Damages-WCB	
47	926	Employee Benefits	
48	930.1	Institutional or Goodwill Advert Exp	
49	930.2	Other Admin. And General Exp	
50		**Total Admin & General-Operation**	**45,800**
51			
52		**Administrative & General - Maintenance**	
53	932	Maintenance of General Plant	24,500
54		**Total Admin & General-Operation**	**24,500**
55			
56		**Regulatory Gross O&M Expense**	**674,400**

On page 46 of the Application, Creative Energy states "Supervision and labour costs relate to the time directly charged by the distribution team for maintenance and monitoring of the NEFC system. The planned cost for 2020 is in line with actuals for 2018."

Line 12 in NEFC Schedule 14 from the Financial Schedules attached to the Evidentiary Update shows the following balances relating to Account #870 – Supervision & Labour for NEFC:

Line #	Acct. #	Account Name	2017 ACTUAL	2018 ACTUAL	2019 Test Year	2020 Test Year
12	870	Supervision & Labour	24,734	52,749	40,002	51,691

In the NEFC compliance filing for Order G-167-16, Line 14 of Schedule 14 shows 2016 Approved and 2017 Approved Supervision and Labour cost of $15,800 and $16,100, respectively.

31.2 Please provide 2016 Actual Supervision and Labour costs and provide an explanation for the variance, if any, between 2016 Approved ($15,800) and 2016 Actual.

RESPONSE:

Operations in NEFC did not commence until 2017. While there were approved rates, there was no actual revenue or costs.

31.3 Please explain the variance in Supervision and Labour costs between the following:

a) 2017 Approved ($16,100) and 2017 Actual ($24,734);
b) 2017 Actual ($24,734) and 2018 Actual ($52,749); and
c) 2018 Actual ($52,749) and 2019 Test Year ($40,002).

RESPONSE:

a) 2017 was the first year of operations. The approved Supervision and Labour was based on a best estimate at that time without any previous data to aid in the estimation. Actual costs were higher than estimated.

b) 2017 was a partial year of operations while 2018 was the first full year. Operations commenced in April 2017. In 2018, additional focus by the distribution team related to flooding at the PARQ Casino location that required an insurance claim.

c) 2018 was higher than 2019 primarily due to the flooding at the PARQ Casino location.

31.4 Please provide the forecast methodology for supervision and labour costs for 2020.

RESPONSE:

The 2020 estimate is based on NEFC requiring 40 percent of a Distribution Team member headcount plus 6 percent of the Distribution team supervisor's time.

31.4.1 Please explain why Creative Energy anticipates that supervision and labour costs for 2020 should be line with 2018 Actuals and not some other amount (e.g. 2019 Test Year, 3-year average of 2016-2019 Actual, other).

RESPONSE:

Supervision and labour costs are allocated based on actual time worked by the distribution team member. The NEFC system added a new customer late in 2019 (Arc). Creative Energy had provided construction heat to that building up until then. In the first year of operations, new customers often require additional attention. In addition, 2019 actuals only included the time directly charged to NEFC system. A percentage of the supervisor's time is allocated on a forecast basis. The additional allocation of Supervisor time is $7,315.

Line 13 in NEFC Schedule 14 from the Financial Schedules attached to the Evidentiary Update shows the following balances relating to Account #874 – Mains & Services for NEFC:

			2017	2018	2019	2020
Line #	Acct. #	Account Name	ACTUAL	ACTUAL	Test Year	Test Year
13	874	Mains & Services		63,892	(42,752)	3,000

31.5 Please explain how Mains and Services costs are determined for the NEFC (e.g. directly charged, allocated cost – Massachusetts Formula, other).

RESPONSE:

Mains and Services costs are directly charged.

31.6 Please explain the variance in Mains and Services costs between the following:

a) 2017 Actual ($0) and 2018 Actual ($63,892); and
b) 2018 Actual ($63,892) and 2019 Test Year (-$42,752); and

RESPONSE:

a) There were no costs incurred in this category in 2017. Costs in 2018 were significant primarily due to repairs related to the PARQ Casino elevator flooding. Costs related to the repairs were $51,894.

b) In 2019, actual costs were offset by proceeds from the insurance claim received in 2019 related to the 2018 flooding. The insurance reimbursement was $46,894. The difference was a $5,000 deductible. Normalized costs for 2018 are $11,998 and 2019 were $4,142 (not including the deductible).

31.7 Please provide the forecast methodology for mains and services costs for 2020.

RESPONSE:

The 2020 forecast cost of $3,000 was based on what NEFC was tracking for 2019 at the time the forecast was developed. Actual costs for 2019 ended up being higher.

31.7.1 Please explain why Creative Energy considers the forecast for Mains and Services costs for 2020 to be reasonable given historical expenditures.

RESPONSE:

In light of final 2019 costs being higher than originally anticipated and 2018 costs also being higher, it is possible that costs should be increased for 2020 in the amount of $5,000 in order to equal the average of 2018 and 2019 described in the response to BCUC 31.6 (b).

Lines 20-24 in NEFC Schedule 14 from the Financial Schedules attached to the Evidentiary Update shows the following distribution expenses related to maintenance for NEFC:

Line #	Acct. #	Account Name	2017 ACTUAL	2018 ACTUAL	2019 Test Year	2020 Test Year
19		**Distribution Expenses - Maintenance**				
20	885	Supervision & Labour				
21	886	Structures & Improvements				
22	887	Mains & Services		123		
23	889	Meters & House Regulators		44		
24	894	Other Distribution Maintenance				
25		**Total Distribution Expenses-Maintenance**	**0**	**167**	**0**	**0**

31.8 Please explain why 2019 Test Year and 2020 Test Year distribution expenses related to maintenance are nil.

RESPONSE:

There were no costs in 2019 coded to these categories and an immaterial amount in 2018. As such, nothing has been forecast for 2020.

On page 46 of the Application, Creative Energy states:

> Administrative and General costs, including related salaries and benefits, office supplies and general legal and audit fees are allocated using the Massachusetts formula. The 2019 allocation is based on the 3-factor methodology using projected 2019 allocable costs across all systems. The 2020 allocation is based on the proposed 2-factor methodology as summarized in section 2.2.

31.9 With reference to the account numbers listed in NEFC Schedule 14, please clarify which costs are allocated to NEFC using the Massachusetts formula.

RESPONSE:

The following accounts include allocations from the Massachusetts Formula:

915	Directors Fees
920	Admin & General Salaries
921	Office Supples & Exp
922	Admin & General Exp
923	Special Services
924	Insurance
925	Injuries & Damages-WCB
926	Employee Benefits

Note that part of the cost related to insurance is directly charged to NEFC as the costs relate specifically to the NEFC equipment.

31.9.1 Please confirm, or explain otherwise, that the costs included in the account numbers provided above do <u>not</u> contain any amounts directly charged to NEFC (i.e. all costs are allocated).

RESPONSE:

As described in the response to BCUC IR 31.9, insurance includes costs that are directly charged.

31.10 Please provide a reconciliation of the account numbers and amounts shown in NEFC Schedule 14 to the total amount allocated to NEFC ($120,837) based on the proposed 2-factor Massachusetts formula, as shown in Table 9 of the Application.

RESPONSE:

Table 9 presents a simplified version for comparison purposes between the 2-factor and 3-factor allocation. The actual allocation to NEFC included insurance costs that were directly charged to NEFC, offset by regulatory costs that were not allocated to NEFC as they are directly attributable to the Core system.

In the Creative Energy 2018-2022 RRA Decision, the BCUC found the proposed Massachusetts formula cost allocation methodology to be acceptable and approved the methodology for application in that Decision and in future revenue requirements. Page 34 of the Creative Energy 2018-2022 RRA Decision described the proposed cost allocation methodology, stating that "costs are allocated only to Other Projects… because NEFC is treated as a steam customer, [Creative Energy] did not apply cost allocations to this entity."

31.11 Please explain why Creative Energy now proposes to apply cost allocations to NEFC using a Massachusetts formula (3-factor for 2019 and 2-factor for 2020).

RESPONSE:

Only steam costs and gas costs get allocated to the NEFC as a customer of the Core steam system. The approved rates for NEFC domestic hot water consumption properly include allocated general and administrative costs administrative costs as allocated out through the Massachusetts formula to support the functions of the NEFC as a separate service area for the provision of domestic hot water service. Therefore, there is no double counting as the Massachusetts formula is picking up that the NEFC is not just a steam customer.

Lines 40-49 in NEFC Schedule 14 from the Financial Schedules attached to the Evidentiary Update show the following administrative and general costs for NEFC:

Line #	Acct. #	Account Name	2017 ACTUAL	2018 ACTUAL	2019 Test Year	2020 Test Year
39		**Administrative & General - Operation**				
40	915	Directors Fees	2,039	2,819	380	3,847
41	920	Admin & General Salaries	51,901	56,812	62,036	62,380
42	921	Office Supplies & Exp	10,716	12,014	12,407	9,670
43	922	Admin & General Exp	442	2,880	679	674
44	923	Special Services	4,927	20,765	17,509	15,060
45	924	Insurance	9,692	12,098	15,971	5,996
46	925	Injuries & Damages-WCB	1,193	1,843	728	602
47	926	Employee Benefits	10,098	9,490	10,447	8,081
48	930.1	Institutional or Goodwill Advert Exp	0	0	0	0
49	930.2	Other Admin. And General Exp	0	0	0	0
50		**Total Admin & General-Operation**	**91,008**	**118,722**	**120,156**	**106,309**

In the Creative Energy NEFC compliance filing for Order G-167-16, Lines 42-47 of Schedule 14 showed the following approved costs:

Account Number	Account Name	2016 Approved	2017 Approved

915	Directors Fees	$8,000	$8,000
920	Admin & General Salaries	$1,500	$6,000
921	Office Supplies & Exp	$4,300	$9,200
922	Admin & General Exp	$0	$0
923	Special Services	$28,500	$6,100
924	Insurance	$12,500	$16,500

31.12 Please clarify how the 2017 Actual and 2018 Actual amounts were determined in Lines 40-49 of NEFC Schedule 14 (e.g. directly charged, allocated cost – Massachusetts Formula, other).

RESPONSE:

The amounts were based on the 3-factor Massachusetts formula.

31.13 Please provide explanations for variances greater than +/- 10 percent in all administrative and general costs (i.e. Lines 40-49 in NEFC Schedule 14) between:

a) 2017 Approved and 2017 Actual;
b) 2017 Actual and 2018 Actual;
c) 2018 Actual and 2019 Test Year; and
d) 2019 Test Year and 2020 Test Year.

RESPONSE:

a)

		2017	**2017**			
		Approved	**Actual**	**Variance**	**%**	**Comments**
915	Directors Fees	8,000	2,039	(5,961)	-75%	2017 budget significantly overestimated the amount of director's fees required for NEFC.
920	Admin & General Salaries	6,000	51,901	45,901	765%	2017 approved expenses were based on incremental costs. For the actual costs the Mass. Formula was used.
921	Office Supplies & Exp	9,200	10,716	1,516	16%	While % change is above 10%, we do not consider the dollar value as significant. Similar to admin & general salaries. This is allocated based on the Mass. Formula.
922	Admin & General Exp	0	442	442	n/a	
923	Special Services	6,100	4,927	(1,173)	-19%	While % change is above 10%, we do not consider the dollar value as significant. Similar to admin & general salaries. This is allocated based on the Mass. Formula.
924	Insurance	16,500	9,692	(6,808)	-41%	NEFC did not have separate property insurance until 2019. Insurance for 2017 was allocated using the Mass. Formula alone.
925	Injuries & Damages-WCB	0	1,193	1,193	N/A	See response to admin & general salaries. These should be viewed in combination.
926	Employee Benefits	0	10,098	10,098	N/A	See response to admin & general salaries. These should be viewed in combination.

b)

		2017	2018			
		Actual	**Actual**	**Variance**	**%**	**Comments**
915	Directors Fees	2,039	2,819	780	38%	While the % change is above 10%, we do not consider the dollar value as significant. This is allocated using the Mass. Formula; actual directors' costs were higher in 2018.
920	Admin & General Salaries	51,901	56,812	4,912	9%	
921	Office Supplies & Exp	10,716	12,014	1,298	12%	While % change is above 10%, we do not consider the dollar value as significant. This is allocated based on the Mass. Formula.
922	Admin & General Exp	442	2,880	2,438	552%	This is allocated using the Mass. Formula. This category is mostly the costs of meals and travel, which were higher in 2018.
923	Special Services	4,927	20,765	15,838	321%	This category is primarily consulting costs and audit and legal fees. It's allocated using the Mass. Formula. Audit fees were higher in 2018 as described in the response BCUC IR 14.3. Legal fees and consulting costs were also higher.
924	Insurance	9,692	12,098	2,406	25%	Allocated using the Mass Formula. Total insurance costs were higher in 2018.
925	Injuries & Damages-WCB	1,193	1,843	650	54%	Should be viewed in combination with admin & general salaries
926	Employee Benefits	10,098	9,490	(608)	-6%	Should be viewed in combination with admin & general salaries

c)

		2018	2019			
		Actual	**Test Year**	**Variance**	**%**	**Comments**
915	Directors Fees	2,819	380	(2,439)	-87%	Director's fees in 2019 are actually nil as there were no 3rd party director fees billed in 2019.
920	Admin & General Salaries	56,812	62,036	5,224	9%	
921	Office Supplies & Exp	12,014	12,407	393	3%	
922	Admin & General Exp	2,880	679	(2,201)	-76%	Allocated using Mass Formula and variance as explained in the Application and in response to BCUC IR 15.3.
923	Special Services	20,765	17,509	(3,256)	-16%	Allocated using the Mass Formula and related variances as explained in the Application.
924	Insurance	12,098	15,971	3,873	32%	In 2019, NEFC assets were separately insured for the first time. These costs directly charged to NEFC. Insurance is now in line with original expectations from the 2017 Approved.
925	Injuries & Damages-WCB	1,843	728	(1,115)	-61%	Should be viewed in combination with admin & general salaries
926	Employee Benefits	9,490	10,447	957	10%	Should be viewed in combination with admin & general salaries

d)

		2019	2020			
		Test Year	**Test Year**	**Variance**	**%**	**Comments**
915	Directors Fees	380	3,847	3,467	913%	Allocated using the Mass. Formula. 2020 Test Year is estimating the addition of 3rd party directors in 2020.
920	Admin & General Salaries	62,036	62,380	343	1%	
921	Office Supplies & Exp	12,407	9,670	(2,737)	-22%	Allocated using Mass. Formula. NEFC's share of the Mass. Formula is decreasing as other energy systems are added in addition to the proposed change to the 2-factor methodology
922	Admin & General Exp	679	674	(5)	-1%	
923	Special Services	17,509	15,060	(2,449)	-14%	Allocated using Mass. Formula. NEFC's share of the Mass. Formula is decreasing as other energy systems are added in addition to the proposed change to the 2-factor methodology
924	Insurance	15,971	5,996	(9,975)	-62%	The 2020 test year requires adjustment as it missed the fact that NEFC's should also have property insurance directly charged to it. The expense currently provided for is only the Mass. Formula allocation for general liability and other shared insurance. An additional cost of $4,151 is required for 2020.
925	Injuries & Damages-WCB	728	602	(126)	-17%	Should be viewed in combination with admin & general salaries.
926	Employee Benefits	10,447	8,081	(2,367)	-23%	Should be viewed in combination with admin & general salaries.

32.0 Reference: NORTHEAST FALSE CREEK REVENUE REQUIREMENTS Exhibit B-1, Section 4.2.3.7, p. 46 Capital Additions

On page 46 of the Application, Creative Energy provides the following table showing 2019 and 2020 Test Year capital additions for the NEFC:

Table 49: NEFC Capital Additions

NEFC Plant Additions	2019	2020	Comment
New customer connection and remaining common costs	359,278		Remaining cost transferred from CIP for new customer connection
PARQ Casino Ventilation	122,754		Life extension of equipment due to cooler temperatures
Heat Exchanger		20,000	Spare
Other	10,736		
	492,768	20,000	

32.1 Please identify any project in Table 49 that has been included and approved as part of any previous application reviewed by the BCUC.

RESPONSE:

The new customer connection related to the new customer (Arc), which was part of the overall plan of capital expenditures presented through the CPCN and revenue requirements and rate design applications for the NEFC.

32.2 For the "PARQ Casino Ventilation" project listed in Table 49, please provide the following information:

i) Project description and scope of work;
ii) Project need and benefits to customers; and
iii) Construction start date and in-service date.

RESPONSE:

i) Project includes engineering and consultation of engineers to identify the size of the required equipment needed, electrical and mechanical requirements of the fan itself and the ductwork and breeching associated with it, installation of all mechanical and electrical equipment, coring through concrete for installation of required equipment, coordination with PARQ Resort for the installation of the ductwork through the existing parkade and venting outside into a common loading dock space and programming with remote operating control system for operation.

ii) The energy center room has poor ventilation which has resulted in the ambient temperature of the room to exceed 52 degrees C at times. The high ambient temperature has already been assessed as the cause of one of the VFD's failure for the hot water distribution/circulation pumps. Improving the ventilation will also lengthen the life span of all the equipment in the DES mechanical room.

iii) Construction started November 9, 2018 and the in-service date was May 16, 2019.

32.3 Please explain the need for a spare heat exchanger.

RESPONSE:

The spare heat exchanger is necessary for contingency purposes. If any one of the buildings on the NEFC system have a heat exchanger failure that building would not be able to be served. At minimum, a heat exchanger takes four weeks to be delivered. This purchase is intended to eliminate the risk of such an event to our customer base.

32.4 Please explain how the capacity of the "Heat Exchanger" capital addition of $20,000 was determined. Is the heat exchanger designed to service customer space heating, domestic hot water or both?

RESPONSE:

The purchase of a heat exchanger is not to add additional capacity, but to replace existing capacity in the event that one of the heat exchangers currently in service should fail. The heat exchanger accommodates both domestic hot water and space heating.

32.4.1 Please confirm whether the heat exchanger is expected to be stored as inventory or put into service. If it is to be put into service, please provide the expected timing.

RESPONSE:

The heat exchanger will be stored in inventory. Please refer to the response to BCUC IR 32.3.

32.5 Please provide the following for the 2019 Test Year "New customer connection and remaining common" costs of $359,278:

RESPONSE:

This primarily relates to new customer Arc which was added late in 2018. Tenants did not occupy units in the building until 2019. An amount of $280,883 was related to Arc from 2018 or earlier. An additional $72,423 relates to 2019 for Arc and $5,973 for common costs.

32.5.1 Please provide a breakdown of the $359,278 between "new customer connection" and "remaining common costs";

RESPONSE:

Please refer to the response to BCUC IR 32.5.

32.5.2 Please explain what is meant by the "remaining common costs"; and

RESPONSE:

When costs coded to the category NEFC Common, it refers to work related to the common area between buildings that does relate to a specific customer, but rather the system as a whole.

32.5.3 Please provide the following for the full scope of this capital addition:

(i) Detailed scope of work and cost break down with accuracy level.
ii) Map(s) showing the existing system and the planned new work. Please include any planned line relocations, line extensions, existing and new customer locations and any other relevant information related to the capital expenditure.
iii) Which customer(s) these costs can be attributed to. If attributable to multiple customers, please provide a breakdown of cost allocation for each customer.
iv) The incremental new load forecasted for each customer listed in the response to iii). Please also include the expected timeline for the forecasted load additions.
v) Confirmation that these capital additions are in service.

RESPONSE:

The scope of all additions, cost breakdowns, diagrams and estimate accuracy levels were described in detail in the CPCN application filed with the Commission on April 17, 2-15 and approved by Order C-12-15. The customer connection for Arc and the remaining common costs are part of the original scope of the project as described in the CPCN application. The capital additions supporting the connection of the four current customers are all in service. Please also refer to the response to BCUC IR 32.5.

Please refer to section 1.2.2 of the Application, and also for example to the responses to BCUC IR Series 25.0, for a discussion of the NEFC Neighbourhood Development Update in respect of the noted components of this IR response in respect of load and timing uncertainty.

32.6 Please provide a financial continuity schedule showing the cost transfers from Construction in Progress (CIP) to Plant in Service account for the years 2015-2018 Actual and 2019-2020 Test Years.

RESPONSE:

Please see continuity schedule below.

	Opening Balance	Transfer from CIP	Ending Balance
2015	**-**	**-**	**-**
2016	**-**	**-**	**-**
2017	**-**	**4,225,661**	**4,225,661**
2018	**4,225,661**	**566,900**	**4,792,561**
2019	**4,792,561**	**492,768**	**5,285,329**
2020	**5,285,329**	**20,000**	**5,305,329**

32.7 Please confirm, or explain otherwise, that the new customer connection(s) shown in Table 49 is not expected to require a Contribution in Aid of Construction.

RESPONSE:

Confirmed.

32.7.1 If confirmed, please explain in detail how Creative Energy determined that the customer connection described in Table 49 does not require a Contribution in Aid of Construction.

RESPONSE:

Connection of the Arc customer is one of the customers planned for under the CPCN application. Under the circumstances of the infrastructure put in place to serve the NEFC service area over time and the associated approval of a levelized rate design (and the use of a rate smoothing RDDA for the reasons explained in section 1.2.1 of the Application) to recover the cost of service over time, no customer contributions in aid of construction are applicable.

32.8 Please confirm, or explain otherwise, that Creative Energy's extension policy for the NEFC service area is the same as for the Core Steam System.

RESPONSE:

Please refer to the response to BCUC IR 32.5.3 and 32.7.1. Creative Energy does not have a different extension policy for the NEFC service area. The addition of new customers and associated load growth in the NEFC and the recovery of the cost of service from NEFC customers over time was considered and approved through the CPCN and the approved rate design.

32.8.1 If not confirmed, please explain the differences and the reasons for the differences; and provide a copy of Creative Energy's extension policy for the NEFC service area.

RESPONSE:

Please refer to the response to BCUC IR 32.8.

33.0 Reference: NEFC REVENUE REQUIREMENTS
Exhibit B-1-1, p. 5
Allowance for Funds Used During Construction (AFUDC)

On page 5 of the Evidentiary Update, Creative Energy states that it added an additional $197,600 to rate base (and Plant in Service) because the Application did not include the full amount of AFUDC as part of the balance of Plant in Service. Creative Energy states the $197,600 is calculated as the difference between the amount of AFDUC which has been added ($11,400) and "the estimated nominal capitalization of interest during construction" ($209,000), which was set out in the Creative Energy 2015 CPCN for the NEFC. Creative Energy states, "[it] considers this estimate to be reasonable noting that an estimate of AFUDC would be $216,713…"

33.1 Please explain why Creative Energy did not propose to correct the AFUDC balance using the estimate of Actual AFUDC (i.e. the $216,713).

RESPONSE:

For the purpose of updating the Plant in Service, the previously approved lower value was used. The difference was not considered material.

33.2 Would Creative Energy be amenable to the above approach? If not, please explain why not.

RESPONSE:

Creative Energy would be amenable to that approach.