HEARST POWER DISTRIBUTION COMPANY LTC (HPDCL)
2021 RATE APPLICATION (EB-2020-0027)
PRE-SETTLEMENT CLARIFICATION QUESTIONS

(Numbering follows from VECC and OEB Staff IR numbering)

VECC-59

REFERENCE: HPDCL IRR Load Forecast, Input Customer Tab

PREAMBLE: In the original Application 2019 was the latest year for which actual customer counts were available and the historic geomean growth rate was used to forecast the GS<50 customer count for both 2020 and 2021. In the IR responses the 2020 customer counts have been updated to reflect actual values and the geomean growth rate was used to forecast 2021 customer/connection counts for all classes except GS<50 where the 2021 count was set equal to the 2020 count.

a) Please explain why a different approach has been used for the GS<50 class and why the 2021 customer count for this class was not forecast using the actual value for 2020 and the historic geomean growth rate.

Hearst Power:

a) **The approach of using Geomean to determine the forecasted customer count works well for medium to larger utilities. However, the methodology and its results are too broad for smaller utilities who know their customers personally and who the economic situation at that specific time, be it a pandemic or a housing crisis, or growth. The results of the Geomean most often need tweaking based on the utility's intimate knowledge of their town and customers. The original application was based on 2019 numbers and subsequently tweaked to adapt it to the reality at that particular time. The same process was used when updating the 2020-year end figures. The results were tweaked to result in a more realistic 2021 customer count.**

VECC-60

REFERENCE: HPDCL IRR Load Forecast, Inputs – Adjustments & Variables Tab
3-VECC-25 a)
1-Staff-1

PREAMBLE: 1-Staff-1 states that in the updated Load Forecast purchases from microFit were subtracted from Wholesale purchases for purposes of determining the purchase power value used in the regression analysis. This adjustment can been seen in the Inputs – Adjustments & Variables Tab of the revised model.

a) Please explain more fully why microFit purchases were subtracted from (as opposed to added to) the Wholesale Purchases for purposes of modelling HPDCL's purchase power requirements.

b) Please provide a revised Load Forecast model where microFit purchases are added to Wholesale Purchases for purposes of developing the model.

Hearst Power:

a) **The wholesale as filed in the original application and subsequently corrected as part of the utility's response to IR included the consumption related to Fit and Microfit connections. Therefore, the consumption was removed as adding it would double the consumption for Fit and Microfit.**

b) **The requested scenario would result in doubling the consumption for Fit and MicroFit, which would be incorrect; therefore, Hearst cannot run the desired scenario.**

VECC-61

REFERENCE: HPDCL IRR Load Forecast, Bridge Year & Test Year Class Forecast Tab
3-Staff-3

a) Please explain why the historic values for the class shares are based on the actual class sales for the year divided by the predicted wholesale purchases for the year as opposed to using the actual whole purchase for the year as the denominator in the calculation.

Hearst Power:

a) **The model intended to use the "actual" wholesale purchases as a denominator in the calculations. The formula was inadvertently changed for a specific scenario and not changed back as intended. The model filed with these responses has been corrected.**

VECC-62

REFERENCE: 3-VECC-30

PREAMBLE: 3-VECC-30 requested "the IESO/OPA report that sets out the persisting savings through to 2021 from Hearst CDM programs implemented in 2011-2014. The response refers to the April 2019 Participation and Cost Report which does not include the requested information.

a) Please provide the report requested in the original interrogatory.

a) **Hearst Power: The requested report has been filed along with these responses.**

VECC-63

REFERENCE: 7-Staff-1
HPDCL IRR Cost Allocation Model, I4 BO ASSETS Tab

a) The response to 7-Staff-1 states: "The contributed capital should have been allocated to Poles (1830), Line transformers (1850) and Services (1855) instead of being completely enter in the line for meters (1860)". However, in the revised Cost Allocation Model the contributed capital is all assigned to Line transformers while the accumulated depreciation on contributed capital is still assigned to Meters. Please reconcile and update the Cost Allocation Model as required.

b) In the original Cost Allocation Model total contributed capital is $124,955. In the IRR Cost Allocation Model the total contributed capital is $109,955. What is the basis for the change?

Hearst Power:

a) In the model filed with these responses, the depreciation expense associated with the capital contribution has been allocated to line transformer instead of meters.

b) The Cost Allocation model uses the average of the opening and closing. When Hearst updated its 2020 to reflect Actuals as part of its responses to IRs, it, in turn, changed the average capital contribution used for cost allocation purposes.

VECC-64

REFERENCE: 7-Staff-4 a) & b)
7-VECC-46
HPDCL IRR Cost Allocation Model, I7.2 Weighting Factors Tab

a) It is noted that in the Cost Allocation Model the Billing and Collecting Weighting Factors have changed. Please provide an updated derivation of the weighting factors similar to that filed with VECC-46 f).

b) In the updated derivation provided in response to part (a), if the total annual cost for each account being allocated does not equal the 2021 cost for that account as set out in Tab I3 (TB Data) of the IRR Cost Allocation Model, please explain why.

c) In the updated derivation provided in response to part (a), if the total bills for each customer class do not equal twelve times the total number of customers in Tab I6.2 of the IRR Cost Allocation Model, please explain why.

Hearst Power:

a) **The Intermediate class should have shown 8.6 instead of 8.9. The tables below show the impact of the change on the resulting R/C ratios. The change is marginal and would not affect the rates as calculated in the March 15 responses to IRs. That said, Hearst commits to updating it as part of the settlement agreement.**

	1	2	3	5	7	8
	Residential	GS <50	GS>50-Regular	GS >50-Intermediate	Street Light	Sentinel
Insert Weighting Factor for Services Account 1855	1.0	2.0	2.0	2.0	0.0	0.0
Insert Weighting Factor for Billing and Collecting	1.0	1.0	1.4	8.9	1.0	1.0

Net Income	$80,750	$1,291	$6,624	$36,862	$13,836	$23,331	($1,193)
RATIOS ANALYSIS							
REVENUE TO EXPENSES STATUS QUO%	100.00%	95.59%	97.03%	117.37%	111.23%	134.42%	62.76%
EXISTING REVENUE MINUS ALLOCATED COSTS	($156,273)	($139,153)	($33,071)	$6,156	($506)	$11,797	($1,495)
	Deficiency Input equals Output						
STATUS QUO REVENUE MINUS ALLOCATED COSTS	($0)	($42,388)	($7,368)	$23,902	$6,670	$20,477	($1,294)
RETURN ON EQUITY COMPONENT OF RATE BASE	8.34%	0.27%	4.18%	19.75%	11.25%	86.02%	-118.25%

With corrected Intermediate Class

	1	2	3	5	7	8
	Residential	GS <50	GS>50-Regular	GS >50-Intermediate	Street Light	Sentinel
Insert Weighting Factor for Services Account 1855	1.0	2.0	2.0	2.0	0.0	0.0
Insert Weighting Factor for Billing and Collecting	1.0	1.0	1.4	8.6	1.0	1.0

Net Income	$80,750	$1,228	$6,611	$36,861	$13,913	$23,331	($1,194)
RATIOS ANALYSIS							
REVENUE TO EXPENSES STATUS QUO%	100.00%	95.58%	97.02%	117.37%	111.37%	134.42%	62.75%
EXISTING REVENUE MINUS ALLOCATED COSTS	($156,273)	($139,215)	($33,084)	$6,154	($430)	$11,797	($1,495)
	Deficiency Input equals Output						
STATUS QUO REVENUE MINUS ALLOCATED COSTS	($0)	($42,450)	($7,381)	$23,901	$6,747	$20,477	($1,294)
RETURN ON EQUITY COMPONENT OF RATE BASE	8.34%	0.26%	4.17%	19.75%	11.31%	86.02%	-118.28%

b) **The initial application and weighting factor calculations were based on the most actual audited balances for 2019. Hearst agrees that the weighting factor calculations could use the test year data of 2021 instead. The revised calculations have been submitted with these responses and results used in the cost allocation model also filed along with these responses.**

c) **Has been corrected**

VECC-65

REFERENCE: 7-VECC-47
7-Staff-2
HPDCL IRR Cost Allocation Model, Tabs I6.1, I6.2 and I8

a) The response to 7-Staff-2 a) states: "The model filed along with these responses has been updated to reflect 100% of the demand for the GS>50 and Intermediate as eligible for transformer allowance". However, in Tabs I6.1, I6.2 and I8 of the Cost Allocation model filed with the IR responses, the customer count and demand values provided for the GS>50 class indicate that only some of the customers in that class own their transformer and are eligible for the transformer allowance. Please reconcile.

Hearst Power:

a) Hearst clarifies that the intermediate class (consisting of 2 customers) are both receiving transformer allowance. However, in the GS>50 class, of the total 37 customers, only 17 receive a transformer allowance.

VECC-66

REFERENCE: 7-Staff-5
HPDCL IRR Cost Allocation Model, Tab I7.1 (Meter Capital)

a) Despite the response to 7-Staff-5, the updated Cost Allocation model does not assign any meter capital to the Intermediate class. Please reconcile.

Hearst Power:

a) VECC is correct, the model has been revised to show 2 meters at tab I7.2

VECC-67

REFERENCE: 8-Staff-1
8-VECC-52 a)

a) In response to 8-Staff-1 HPDCL files an updated RTSR Workform. While the HON rates have been updated for the 2021 rates it appears the UTRs have not. Please provide an updated RTSR Workform that also uses the 2021 UTRs.

b) In 8-VECC-52 a) VECC sought to confirm that the RRR data used in Tab 3 of the RTSR Workform was based on the same year as the billing data used for Tab 5. Please provide a response to this question.

Hearst Power

a) and b): The RTSR model filed along with these responses reflects the most up to date UTR. The inputs at Tab 5 reflect 2020 information however, the RRR data at tab 3 still reflect 2019 as the RRR information has not yet been compiled for the end of April annual RRR filing.

VECC-68

REFERENCE: 8-VECC-53

a) With respect to the Tariff Schedule filed with the IR responses, please confirm that the 2021 Retail Services Charges still need to be updated to reflect the Board's EB-2020-0285 Decision and Rate Order.

b) Does the Other Revenue forecast from Retail Service Charges need to be revised to reflect the Board's EB-2020-0285 Decision and Rate Order?

Hearst Power:

a) Hearst assumes that OEB staff will make the necessary changes to its models to reflect the most up to date retail service charges prior to the draft rate order.
b) The projections for the 2021 consider inflation therefore Hearst believes that the changes are embedded in its other revenues.

VECC-69

REFERENCE: HPDCL IRR Load Forecast, Wholesale Analysis Tab
HPDCL IRR Chapter 2 Appendices, Appendix 2-R
(Loss Factors)

a) The historical wholesale purchase values used in Appendix 2-R do not appear to reconcile with those used in the Load Forecast model. Please explain.

Hearst Power:

a) The load forecast filed on March 15 shows the following total consumption for 2015-2019. The kWh delivered used for determining the loss factor, also filed on March 15 is shown below. The information in both table reconcile.

Wholesale	2015	2016	2017	2018	2019
January	9,099,544	8,543,096	7,845,581	8,481,553	8,510,987
February	8,701,851	8,254,332	7,284,619	7,731,476	7,650,576
March	8,390,410	7,953,342	7,904,228	7,708,272	7,662,070
April	7,156,774	6,889,002	6,552,389	6,889,436	6,705,872
May	6,398,935	6,312,694	6,375,887	6,271,696	6,277,699
June	5,833,979	6,102,694	5,909,841	5,644,443	5,726,759
July	5,635,164	5,558,234	5,672,267	5,335,274	5,939,254
August	5,309,139	5,993,450	5,610,906	5,715,550	5,548,909
September	5,864,188	5,878,746	5,852,156	5,744,145	5,914,453
October	6,751,138	6,256,770	6,331,276	6,885,613	6,569,798
November	7,076,988	6,579,153	7,361,568	7,420,690	7,241,336
December	7,758,514	7,956,631	8,160,244	7,418,845	7,688,010
Total	**83,976,623**	**82,278,142**	**80,860,964**	**81,246,992**	**81,435,722**

Loss Factors

	Historical Years					5-Year Average
	2015	2016	2017	2018	2019	
Losses Within Distributor's System						
"Wholesale" kWh delivered to distributor (higher value)	83,976,623	82,278,142	80,860,964	81,246,992	81,435,722	81,959,689
"Wholesale" kWh delivered to distributor (lower value)	83,858,854	82,168,544	80,785,628	81,140,149	81,342,264	81,859,088
Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)	-	-	-	-	-	-
Net "Wholesale" kWh delivered to distributor = **A(2) - B**	83,858,854	82,168,544	80,785,628	81,140,149	81,342,264	81,859,088
"Retail" kWh delivered by distributor	81,102,524	79,434,938	77,270,822	78,280,120	77,748,075	78,767,296
Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)		-	-	-	-	-
Net "Retail" kWh delivered by distributor = **D - E**	81,102,524	79,434,938	77,270,822	78,280,120	77,748,075	78,767,296
Loss Factor in Distributor's system = **C / F**	1.0340	1.0344	1.0455	1.0365	1.0462	1
Losses Upstream of Distributor's System						
Supply Facilities Loss Factor	1.0227	1.0227	1.0227	1.0227	1.0227	1.0198
Total Losses						
Total Loss Factor = **G x H**	1.0575	1.0579	1.0693	1.0601	1.0700	1.0598

1-Staff-101
Overall Scorecard
Ref 1: 1-Staff-6

Hearst Power stated in reference 1 that the SAIDI and SAIFI have increased when compared to the last submitted DSP mainly due to scheduled maintenance interruptions, which account for 58% of the SAIDI average and 35% of the SAIFI average. For part of the question, Hearst Power stated that the 4.33 value in 2017 for System Reliability is 68.4% due to Scheduled interruptions for pole changes. The poles replaced in 2017 included more complex, critical circuit poles, as well as heavily loaded poles than when compared to other years in that same table.

a) With Hearst Power's plan to increase pole replacements, please clarify if Hearst Power anticipates increases in SAIDI, SAIFI and System Reliability – Average Number of Hours that Power to a Customer is Interrupted.
b) Please explain any strategies Hearst Power is planning to use to prevent or minimize the potential increases in SAIDI and SAIFI due to increase pole replacements.
c) Please clarify if Hearst Power anticipates any year in the next five years which would include replacement of more complex, critical circuit poles, as well as heavily loaded poles, as was the case in 2017.
d) Please quantify, in terms of SAIDI (minutes), the difference between a proactive pole replacement and a reactive pole replacement based on Hearst Power's historical experience.

Hearst Power:

a) Hearst expects similar results as per year 2017 to 2019
b) As per the DSP, Hearst Power will continue to install in-line switches to help reduce outage sizes where possible; will continue to add circuits loops to reduce outage sizes where possible; and Hearst Power is always planning and organizing its pole replacement program strategically, taking into account multiple factors which include minimizing outage times.
c) The most recent complete pole survey identified 223 that needs to be replaced within the next years. In those 223 deteriorated poles, complex, heavily loaded and critical circuit poles are included and the replacement of those is prudently planned to take into consideration these facts in addition to customer outages and available budgets. HPDC does not currently anticipate a material difference in pole changes capital cost in the next five years.
d) Proactive= Changing a pole before it breaks or falls apart (completed typically within 3-6hrs with a 1-hour outage)
e) Reactive= Changing a pole after it breaks or falls apart (completed typically within 4-7hrs with a >4-hour outage)

2-Staff-102
Transformer Replacement
Ref 1: 2-Staff-3

Hearst Power stated in reference 1 that proactive transformer replacement is based on condition assessment with age also being a factor. The main driver of the proactive replacement of transformers is to lessen the risk of equipment failing in service resulting in unplanned outages for customers and added Operations & Maintenance costs for the utility. Moreover, Hearst Power states that the proactive approach is proposed to start the replacement of the very large quantity of 50 years or older transformers currently in-service.

a) Please clarify if condition assessment is done using visual inspection, or any other factors than taking into account the age of the transformer.
b) Please clarify the number of instances in the past five years where a long outage was caused by transformer failure.
c) Please explain the number of 50 years or older transformers currently in-service and how many of them Hearst Power plans to replace in the next five years.

Hearst Power:

a) **The factors include Age, Visual inspection of components, Infrared testing**
b) **As identified in the DSP page 52 to 68:**

Date	Location	Code	Description	Cause	Customer Interrup. No. Customers affected	Duration (Hours)	Customer Hours
					A	B	A x B
July 11/15	141 Gaspesie Road	5	Defective equipment	Defective transformer	2	8.7	17.3
July 27/15	10 Cloutier Rd South	5	Defective equipment	Burnt transformer	4	11.1	44.2
Nov 4/15	15 Gaspesie Road	5	Defective equipment	Shorted transformer	1	1.3	1.3
Nov 4/15	14 Gaspesie Road	5	Defective equipment	Shorted transformer	2	4.5	8.9
Dec. 16/15	40- 15th Street	5	Defective equipment	Blown elbow in transformer	43	1.2	51.6
14-Jun-16	1007 Edward Street	5	Defective equipment	Blown transformer	1	17.93	17.93
10-Jul-16	Tremblay, Quirion & Picard St.	5	Defective equipment	Blown elbow in padmount transformer	73	0.2	14.6
10-Jul-16	Chalykoff St.	5	Defective equipment	Blown elbow in padmount transformer	16	3.283	52.53
10-Jul-16	Tremblay & Quirion St.	5	Defective equipment	Blown elbow in padmount transformer	34	1.556	52.9
16-Sep-16	Chalykoff Street	5	Defective equipment	Blown elbow in padmount transformer	16	2.2333	35.73
21-Sep-16	Part of West, Houle, 15th, MacManus	1	Scheduled Outage	Padmount transformer leaking oil	159	1.7833	283.54
19-Jun-17	Ninth Street (University)	5	Defective equipment	Blown transformer on 3 Ph bank	2	9.58	19.16
05-Sep-17	214 Hwy 11 East	5	Defective equipment	Blown transformer	1	40.85	40.85
24-Apr-18	Houle, Aubin, 15th and P	5	Defective equipment	Transformer leaking oil	52	1.4333	74.5316
31-May-18	1320 Edward St	5	Defective equipment	Blown transformer	6	1.983	11.898
05-Jul-18	Maisonneuve	5	Defective equipment	Blown elbow in padmount TX	152	1.25	190
30 Oct 2020	15th St, Houle and Powell	5	Defective equipment	Broken elbow in padmount transformer	44	1.5666	68.9304
2 Dec 2020	Chalykoff, Place Doucet	5	Defective equipment	Blown elbow and bushing well insert	17	1.9833	33.7161
2 Dec 2020	Tremblay, Chalykoff, Place Doucet	5	Defective equipment	Blown elbow and bushing well insert	106	0.45	47.7

Since HPDC is not aware of the OEB specific details for classifying as "long outages", HPDC highlighted in yellow >2hr outages cause by failed transformers.

To better explain the information above and the reason for having one outage represented in multiple row (ex: July 10, 2016) is due to the HPDC staff restoring power to some customer by decreasing the outage size and using available equipment to do so. For example: On July 10, 2016 a TX elbow blew, then a crew was dispatched and able to restore power to 73 of the 123 customers affected. Then, around 80 minutes later a second set of customers was able to be re-energized, and finally another 104 after the final residential 16 customers were able to be re-energized.

c) The following information was extracted from the DSP page 27 of 138, Graph 3:

Decade	2010	2000	1990	1980	1970	1960	1950
# O/H Tx	49	43	30	113	237	80	1
# U/G Tx	2	5	18	13	27	0	0

>50 years transformers are highlighted in yellow above. Starting in 2022, HPDC expects to replace around 7 transformers per year based on the condition assessment results and factors identified in a)

2-Staff-103
Smart Meters
Ref 1: 2-Staff-10

Hearst Power stated in reference 1 that Hearst Power has not pursued other ancillary equipment but did check if the existing system could provide alarms.

a) Please clarify if the existing systems could be upgraded to provide an alarm to notify of the occurrence and location of faults in real time. If so, has Hearst Power considered the reliability benefits of this alarm compared to the costs?

Hearst Power:

a) The HPDC has reviewed this and the central point database does not have alarm capabilities. As noted in the DSP, Hearst Power does not have SCADA and SCADA would be required for such alarms to be generated. Adding SCADA to our existing system would obviously be very expensive and would increase customer distribution fees while not providing justifiable value for this increase.

2-Staff-104
Capital Expenditure
Ref 1: 2-Staff-19

Hearst Power stated in reference 1 that Hearst Power has made efforts to defer some capital expenditure projects, but the System Renewal project is the pole replacement program which is required to maintain reliable performance.
OEB staff notes a significantly higher capital expenditure during the test year can lead to higher distribution rates due to the rates being based on test year.

a) Please clarify if Hearst Power has considered switching to a reactive approach for pole replacement for the test year in order to not have significantly higher capital expenditure during the test year.
b) Please provide an estimate of how much capital expenditure for pole replacement program can be deferred from test year by switching to a reactive approach of replacement only for the test year.

a) and b)

Proactive= Changing a pole before it breaks or falls apart
Reactive= Changing a pole <u>after</u> it breaks or falls apart

Hearst Power feels very strongly against switching to reactive approach. Reactive approach is very dangerous to the public and will cause significant cost increase over the years to come.

The Town of Hearst started electrification in the years 1952's and many poles, from the 1950's & 1960's, are still in operation. Leaving them for replacement based on reactive approach would greatly endanger HPDC's customer's safety, its reliability, financial viability and reputation.

In pole assessment survey was completed in 2019 and identified 223 poles that are requiring to be replace as they are to deteriorated to last more than 5 years. Deferring poles from 2020 to the 2021-2025 years, would only achieve a higher capital cost during the next 2021-2025 years, therefore increasing hydro rates.

Please note that HPDC does not have sufficient crew capabilities to replace over 50 poles per year. If over 50 poles needed to be replaced in one single year, extra subcontracting costs from third parties would be incurred and these can be significantly impactful costs as there are no local subcontractors offering this service.

2-Staff-105
Ref 1: 2-Staff-20
Hearst Power stated in reference 1 that Hearst Power has reviewed options for protecting against animal contacts, particularly after the 2016 experience.

a) Please explain the options Hears Power has reviewed for protecting against animals.
b) Please explain if Hearst Power already has or plans to in the future implement any of the options considered. If not, please explain why the options are not deemed feasible.

Hearst Power:

a) **Hearst Power has investigated jump barriers and line rollers for critters and bird diverters for crows and other birds.**

b) **Hearst Power does have and does not plan to implement these in the future. Taking into consideration that Hearst is located in the very north of Ontario and trees and wildlife is found everywhere (see below arial view). Hearst is known for a dense Moose, Black Bears, and other wildlife populations. Hearst is a prime spot for hunters.**

Most commonly, the crows interact with the powerlines and cause fuses to trip just about anywhere. There are thousands and thousands of birds in HPDC's geographical areas, with includes 81 km of overhead lines, and no options investigated was worth the money to spend in order to provide actual noticeable results.

3-Staff-06
Ref 1: 3-Staff-6
Ref 2: 3-VECC-26
Ref 3: Load Forecast Model

Hearst states that the shutdown flag denotes when the factory is shut in the summer. In the second reference, it indicates that the shutdown is typically approximately one week, in July or August. The shutdown flag in the load forecast as updated through the interrogatories indicates 0 in June and July, and 1 in all other months. The coefficient for the shutdown variable is now -141,649, indicating that in months of January-May and August-September, the load is 141,649kWh lower than it is in the summer. Conversely, this means that the load is higher in the summer when the mills have their shutdown.

The CDD variable has a coefficient of -2,909, indicating that for each additional degree day of heat, 2,909 kWh less energy is used. In addition, the explanatory variable has t-stat of -1.003 indicating that it does not meet the criteria for statistical significance of greater than 2, or less than -2.

a) Please explain the counter-intuitive result that the factory closes in the summer, yet the load is lower in the rest of the year?
b) As a scenario, please provide a model where CDD is not used as an explanatory variable, and where the shutdown variable is indicative of the actual shutdown months.

Hearst Power:

a) And b) Hearst notes that are not considered clarification but rather supplemental IRs.

On the subject of statistical significance, Hearst is not aware of an OEB policy which defines a threshold for statistical significance within a regression analysis. Hearst respectfully requests that Board Staff provide the utility with the specific policy or filing requirement to that effect.

Hearst's climate is different and colder than the GTA area therefore the utility feels that the use of CDD is not only logical but appropriate, especially in Hearst case. Moreover, the Adjusted R-Squared of 88.97 does not change when CDD is removed as a variable.

Results with CDD as filed on March 15

Equation Parameters			95% Confidence/Autocorrelation		Predicted
R Squared	0.8953	88.97% of the change in WS can be explained by	1.683	Durbin-Watson Statistic	
Adjusted R Squared	0.8897	the change in the 6 independent variables	1.62 - 1.79	Positive autocorrelation detected	
Standard Error	360622.1250	to +/- on result of Regression Equation	2.176	Critical F-Statistic - 95% Confidence	
F - Statistic	160.9978	Therefore analysis IS Significant	91.87%	Confidence to which analysis holds	

Multiple Regression Equation					Independent Analysis			Auto Correlation	Multicollinearity	
	Coefficients	Standard Error	t Stat	p Value	R Squared	Coefficient	Intercept	Dl=1.69 Du=1.72 DW-Stat	Adjusted R-Squared against other Indep	Variables With RSQ at > 90%
Intercept	-18,430,707.494	6,026,220.740	-3.058	0.28%						
HDD	2,641.887	196.627	13.436	0.00%	87.90%	2781.65	5430916.50	0.32	77.97%	
CDD	-2,908.930	2,900.471	-1.003	31.80%	34.34%	-35606.72	7184151.00	1.08	57.54%	
Customer #	8,138.452	2,130.442	3.820	0.02%	0.71%	5866.12	-9368988.00	1.21	-3.05%	
Days in month	54,880.256	42,880.216	1.280	20.32%	2.35%	-206346.49	13125964.00	2.98	4.85%	
Spring/Fall	-149,808.696	118,146.054	-1.268	20.74%	57.85%	-1663828.52	7801134.50	0.76	66.84%	
Shutdown	-141,649.142	121,391.672	-1.167	24.57%	22.84%	1386856.75	5688719.00	1.20	44.73%	

Results w/o CDD

Equation Parameters			95% Confidence/Autocorrelation		Predicted
R Squared	0.8943	88.97% of the change in WS can be explained by	1.687	Durbin-Watson Statistic	
Adjusted R Squared	0.8897	the change in the 5 independent variables	1.63 - 1.77	Positive autocorrelation maybe present	
Standard Error	360631.3750	to +/- on result of Regression Equation	2.290	Critical F-Statistic - 95% Confidence	
F - Statistic	192.9863	Therefore analysis IS Significant	89.62%	Confidence to which analysis holds	

Multiple Regression Equation					Independent Analysis			Auto Correlation	Multicollinearity	
	Coefficients	Standard Error	t Stat	p Value	R Squared	Coefficient	Intercept	Dl=1.69 Du=1.72 DW-Stat	Adjusted R-Squared against other Indep	Variables With RSQ at > 90%
Intercept	-17,873,440.441	6,000,703.135	-2.979	0.35%						
HDD	2,734.265	173.722	15.739	0.00%	87.90%	2781.65	5430916.50	0.32	72.03%	
Customer #	7,985.832	2,125.055	3.758	0.03%	0.71%	5866.12	-9368988.00	1.21	-2.68%	
Days in month	45,799.169	41,914.386	1.093	27.68%	2.35%	-206346.49	13125964.00	2.98	1.27%	
Spring/Fall	-115,066.604	112,956.365	-1.019	31.05%	57.85%	-1663828.52	7801134.50	0.76	64.03%	
Shutdown	-86,051.731	107,997.291	-0.797	42.72%	22.84%	1386856.75	5688719.00	1.20	30.77%	

Results with shutdown flag as filed on March 15 Shutdown June/July

Equation Parameters			95% Confidence/Autocorrelation		Predicted
R Squared	0.8953	88.97% of the change in WS can be explained by	1.683	Durbin-Watson Statistic	
Adjusted R Squared	0.8897	the change in the 6 independent variables	1.62 - 1.79	Positive autocorrelation detected	
Standard Error	360622.1250	to +/- on result of Regression Equation	2.176	Critical F-Statistic - 95% Confidence	
F - Statistic	160.9978	Therefore analysis IS Significant	91.87%	Confidence to which analysis holds	

Multiple Regression Equation					Independent Analysis			Auto Correlation	Multicollinearity	
	Coefficients	Standard Error	t Stat	p Value	R Squared	Coefficient	Intercept	Dl=1.69 Du=1.72 DW-Stat	Adjusted R-Squared against other Indep	Variables With RSQ at > 90%
Intercept	-18,430,707.494	6,026,220.740	-3.058	0.28%						
HDD	2,641.887	196.627	13.436	0.00%	87.90%	2781.65	5430916.50	0.32	77.97%	
CDD	-2,908.930	2,900.471	-1.003	31.80%	34.34%	-35606.72	7184151.00	1.08	57.54%	
Customer #	8,138.452	2,130.442	3.820	0.02%	0.71%	5866.12	-9368988.00	1.21	-3.05%	
Days in month	54,880.256	42,880.216	1.280	20.32%	2.35%	-206346.49	13125964.00	2.98	4.85%	
Spring/Fall	-149,808.696	118,146.054	-1.268	20.74%	57.85%	-1663828.52	7801134.50	0.76	66.84%	
Shutdown	-141,649.142	121,391.672	-1.167	24.57%	22.84%	1386856.75	5688719.00	1.20	44.73%	

Results with CDD Shutdown July/Aug

Equation Parameters				95% Confidence/Autocorrelation
R Squared	0.8945	88.89% of the change in WS can be explained by	1.714	Durbin-Watson Statistic
Adjusted R Squared	0.8889	the change in the 6 independent variables	1.62 - 1.79	Positive autocorrelation maybe present
Standard Error	361966.1563	to +/- on result of Regression Equation	2.176	Critical F-Statistic - 95% Confidence
F - Statistic	159.6648	Therefore analysis IS Significant	91.87%	Confidence to which analysis holds

Predicted

	Multiple Regression Equation				Independent Analysis			Auto Correlation	Multicollinearity	
	Coefficients	Standard Error	t Stat	p Value	R Squared	Coefficient	Intercept	DI=1.69 Du=1.72 DW-Stat	Adjusted R-Squared against other Indep	Variables With RSQ at > 90%
Intercept	-17,584,386.382	6,035,545.741	-2.913	0.43%						
HDD	2,619.514	196.021	13.363	0.00%	87.90%	2781.65	5430916.50	0.32	77.67%	
CDD	-2,779.609	3,257.472	-0.853	39.53%	34.34%	-35606.72	7184151.00	1.08	66.09%	
Customer #	7,993.193	2,133.803	3.746	0.03%	0.71%	5866.12	-9368988.00	1.21	-3.49%	
Days in month	39,603.455	43,561.565	0.909	36.52%	2.35%	-206346.49	13125964.00	2.98	7.11%	
Spring/Fall	-151,361.601	118,843.494	-1.274	20.54%	57.85%	-1663828.52	7801134.50	0.76	66.98%	
Shutdown	-104,161.885	145,300.794	-0.717	47.49%	24.88%	1447232.32	5638406.50	1.20	61.13%	

4-Staff-107
Ref 1: 4.0-VECC-32

Hearst Power stated in reference 1 that Account 5630-Outside Services Employed increased from $94,069 to $123,000 from 2020 to 2021. The OEB approved 2015 cost for this account was only $27,000.

In addition, OEB staff notes that Billing and Collecting expenses increased from $282,250 to $328,564 from 2015 OEB approved to 2021.

a) Please provide a full breakdown of costs for Account 5630-Outside Services Employed in 2021.
b) Please explain the large increase in Account 5630-Outside Services Employed cost from 2015 OEB approved to 2021.
c) Please explain the process Hearst Power follows when hiring outside services. Does Hearst Power follow a bidding process to choose consultants?
d) Please provide a full breakdown of cost increases in Billing and Collecting resulting in the 16.4% increase from 2015 OEB approved to 2021.

Hearst Power:

a) and b)

The table below answers both questions:

Third Party Service provided (Acc #5630)	2015	2021	Note
IT and website services	$2,500	$20,000	Increase cost for Cybersecurity and website management
Billing Third service provider	$3,500	$6,000	
Accountants	$21,000	$28,000	
Legal	$0	$8,000	
Mutal Funds management fees	$0	$8,000	2015= savings were left in the bank account for safety and did not generate interest income; 2021 = Savings are invested to generate revenues and lower distribution rates.
Smart Meters readings & data management	$0	$40,000	These fees were not included in the budget 2015 COS as the Smart Meter Disposal was not complete at the time of application, therefore these cost weren't yet approved to be included in account #5630. Once the smart meter disposal was complete, HPDC was allowed to include these costs in account 5630 instead of using the DEFVARs accounts.
Smart Meter synchronization	$0	$7,500	
MIST metering readings and data management	$0	$5,500	New OEB requirement for MIST meters
Total	**$27,000**	**$123,000**	

c) **Hearst Power hires third party service providers or purchases all material but on the company procurement policy. (see attached Procurement policy - Hearst Power)**

d) **Please see table below for breakdown of billing of collecting representing a $46k variance over the 2015 OEB approved and $24k over the 2015 actuals.**

	Board Appr.			Variance ($)	
Account - Description	**2015**	**2015**	**2021**	**2021 vs 2015 OEB**	**2021 vs 2015 actual**
5310-Meter Reading Expense	$22,602	$23,405	$18,194	-$4,408	-$5,211
5315-Customer Billing	$206,421	$208,062	$224,475	$18,054	$16,413
5320-Collecting	$26,160	$42,892	$47,150	$20,990	$4,258
5330-Collection Charges	$1,618	$1,447	$820	-$798	-$627
5335-Bad Debt Expense	$14,557	$7,006	$13,325	-$1,232	$6,319
5340-Miscellaneous Customer Accounts Expenses	$10,892	$21,420	$24,600	$13,708	$3,180
Total - Billing and Collecting	**$282,250**	**$304,232**	**$328,564**	**$46,314**	**$24,332**

None of the values above are considered material based on the OEB set threshold for HPDC but clarifications are provided below for differences over $10k.

Account #5315 – Customer Billing: The variance of $18,054 from the 2021 vs 2015 OEB approved relates to employee salary inflation representing an average of 1.5% increase per year for 6 years.

Account #5320 – Collection services: The variance of $20,990 from the 2021 vs 2015 OEB approved relates a lower value in the 2015 OEB approved versus actuals. The actuals amount for 2014 was $30,549 which is lower then 2015 OEB approved. Increases from since 2014-2015 are principally driven by salary inflation related to Town employees (receptionist, cashier and payroll is a shared service between Hearst Power and Town of Hearst, please refer to Inter-Corporate Agreement). Hearst Power pays a fixed price for these services provided by the Town employees for HPDC.

Account #5340 – Misc. Customer Accounts Expenses: The variance of $13,708 from the 2021 vs the 2015 OEB approved is driven by third party 911 and after hours call out and dispatch service. As of November 30th, 2014, the contract with our service provider ended and it was renewed in 2015. An increase occurred based on our request for service and their actual cost to provide as they specified the previous contract was insufficient to continue these services. The current pricing is effect until December 31st, 2023.

7-Staff-108
Ref 1: 7-Staff-2
Ref 2: Cost Allocation Model, sheet I6.1 Revenue, sheet I6.2 Customer Data, sheet I8 Demand Data

In sheet I6.1, Hearst indicates that 50,751 of 65,291 kW (78%) is eligible for transformer ownership allowance as it is delivered using customer owned transformers. On sheet I8, Hearst Power indicates in the NCP4 allocator that 12,686 kW of 16,320 kW (78%) is served by Hearst Power owned transformers. The same proportion of load served using Hearst Power owned transformers applies to NCP1 and NCP12.

a) Please reconcile the apparent discrepancy that a large majority of the load is served by customer owned transformers on sheet I6.1, while the same large majority of load is served by Hearst Power owned transformers at sheet I8.

Hearst Power:

a) The information provided at both the Revenue Tab (I6.1), the customer count at I7.1 are based on statistics. Although almost 50% of the customers own their transformers, not all customers in a particular class use the same amount of energy. If there is an issue with the adjustment in the load profiles, Hearst requires more direction from Staff as to what adjustments are to be done in that respect.

7-Staff-109
Ref 1: Cost Allocation Model sheet O1 Revenue to cost|RR

Ref 2: Revenue Requirement Work Form, sheet 11. Cost_Allocation

The allocated revenue requirement from the cost allocation model does not match the allocated revenue requirement in the RRWF.

a) Please update the RRWF to reflect the cost allocation model, as updated for any changes Hearst Power proposes to make in response to pre-ADR clarification questions.

Hearst Power:

a) Hearst is not proposing any adjustment to the Rate Base or Revenue Requirement however, Hearst has corrected several inputs in the cost allocation model and as such the rates have seen a slight adjustment. See RRWF attached.

7-Staff-110
Ref 1: 8-Staff-2
Ref 2: Chapter 2 Appendices, Appendix 2-R, December 11, 2020
Ref 3: Chapter 2 Appendices, Appendix 2-R, March 18, 2021
Ref 4: EB-2019-0040, Tariff of Rates and Charges.

OEB staff asked about higher losses in 2017 and 2019. Hearst Power states that it updated Appendix 2-R to reflect correction to wholesale and retail. OEB staff note that despite the correction, the losses are still higher in 2017 and 2019.

In the initial application, Hearst Power calculated a loss factor of 1.0538. In the update through the interrogatories, the proposed loss factor is 1.0598 OEB staff note that the current, approved loss factor is 1.0414.

OEB staff notes that a supply facility loss factor of 1.0198 has been entered in every year. The ratio of wholesale on line A(1), 81,959,689 kWh to A(2), 81,859,088 kWh is 1.0012:1 implying a wholesale loss factor of 1.0012.

The RRR filings indicate a wholesale purchases inclusive of embedded generation as follows:

2015: 83,988,159 kWh
2016: 82,299,883 kWh
2017: 80,151,361 kWh
2018: 80,509,366 kWh
2019: 80,714,683 kWh

a) Please explain why the losses remain higher in 2017 and 2019 despite the correction.

b) Please provide a derivation of the supply facility loss factor of 1.0198, and explain why this isn't reflected in the ratio of A(1) to A(2).
c) Please explain the cause of the increase in losses from the current approved loss factor to the proposed loss factor for 2021.
d) Please reconcile the RRR kWhs to the A(1) wholesale values provided in Appendix 2-R – in particular, the variances in 2017, 2018 and 2019.

Hearst Power:

a) Hearst Power does not have a specific explanation for the approximately <1% higher load factor in 2017 and 2019 when compared to 2018. On a 10-year loss factor comparison based on the table below which ranges from loss between 3.4% and 4.5%, it can be noticed that some years have slightly higher loss values than others. Hearst Power does not believe the slightly higher value required further investigation.

	(A)	(B)	
Year	A(1) "Wholesale" kWh delivered to distributor (higher value)	Total Sold (Delivered by LDC) - As per Load Forecast	Loss % - (A-B)/A
2010	77,604,491	74,090,335	4.528%
2011	81,563,046	77,886,428	4.508%
2012	82,731,701	79,919,925	3.399%
2013	86,092,785	82,731,372	3.904%
2014	86,106,576	84,214,727	2.197%
2015	83,976,623	81,102,524	3.422%
2016	82,278,142	79,434,938	3.456%
2017	80,860,964	77,270,822	4.440%
2018	81,246,992	78,280,120	3.652%
2019	81,435,722	77,748,075	4.528%

Due to large FIT generator connected to grid, but with no contract for payment (generated "metered" kwh flowing from Hearst Power to Hydro One, therefore reducing H1's billed kWh to Hearst Power)

b) If partially embedded, SFLF should be calculated as the weighted average of above.

	2019			
	Consumption	**weight**	**rate**	**Total**
IESO	27040995	0.3321	1.0045	0.3335
Hydro One	43814453	0.5380	1.0340	0.5563
MicroFit	606999	0.0075	1.0000	0.0075
Fit	9973274	0.1225	1.0000	0.1225
Total	**81435721**	**0.8701**	**2.0385**	**1.0198**

c) **The MFR state the following, "*If the proposed distribution loss factor is greater than 5%, an explanation for the level of the loss factor, details of actions taken to reduce losses in the previous five years, and actions planned to reduce losses going forward*"**

Hearst notes that its distributor-controlled loss factor is lower than previous years and is lower than the threshold of 5%.

		Historical Years					5-Year Average
		2015	2016	2017	2018	2019	
	Losses Within Distributor's System						
A(1)	"Wholesale" kWh delivered to distributor (higher value)	83,976,623	82,278,142	80,860,964	81,246,992	81,435,722	81,959,689
A(2)	"Wholesale" kWh delivered to distributor (lower value)	83,858,854	82,168,544	80,785,628	81,140,149	81,342,264	81,859,088
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)	-	-	-	-	-	-
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	83,858,854	82,168,544	80,785,628	81,140,149	81,342,264	81,859,088
D	"Retail" kWh delivered by distributor	81,102,524	79,434,938	77,270,822	78,280,120	77,748,075	78,767,296
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)		-	-	-	-	-
F	Net "Retail" kWh delivered by distributor = **D - E**	81,102,524	79,434,938	77,270,822	78,280,120	77,748,075	78,767,296
G	Loss Factor in Distributor's system = **C / F**	1.0340	1.0344	1.0455	1.0365	1.0462	1.0393

d) **The RRRs do not balance as the embedded generation provided in the RRR portal only include large generator and MicroFit generation was not reported as wholesale value:**

RRR values	**2017**	**2018**	**2019**	
RRR Power purchase (Hydro One/IESO)	70,309,558	70,291,494	70,741,409	
FIT Embedded power purchase	9,841,803	10,217,872	9,973,274	
Total RRR	**80,151,361**	**80,509,366**	**80,714,683**	
To reconcile				
Missing MicroFit Generation in RRR wholesale	*634,267*	*630,783*	*627,580*	
Total RRR values + reconciliation	**80,785,628**	**81,140,149**	**81,342,264**	(A)
As per Chapter 2 Appendices, Appendix 2-R	**2017**	**2018**	**2019**	
A(2) "Wholesale" kWh delivered to distributor (lower value)	**80,785,628**	**81,140,149**	**81,342,264**	(B)
Variance A - B	-	-	-	