BY E-MAIL

February 22, 2021

Christine E. Long
Registrar and Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto ON M4P 1E4

Dear Ms. Long:

Re: Hearst Power Distribution Company Ltd. (Hearst Power)
Application for 2021 Electricity Distribution Rates
OEB Staff Interrogatories
Ontario Energy Board File Number: EB-2021-0027

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

Hearst Power's responses to interrogatories are due by March 15, 2021.

Yours truly,

Abdullah Navid
Analyst – – Electricity Distribution: Major Rate Applications & Consolidations

Attachments

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

Exhibit 1- Administration

1-Staff-1 Manuela

Updated Revenue Requirement Work Form (RRWF) and Models

Upon completing all interrogatories from Ontario Energy Board (OEB) staff and intervenors, please provide an updated RRWF in working Microsoft Excel format with any corrections or adjustments that the Applicant wishes to make to the amounts in the populated version of the RRWF filed in the initial applications. Entries for changes and adjustments should be included in the middle column on sheet 3 Data_Input_Sheet. Sheets 10 (Load Forecast), 11 (Cost Allocation), 12 (Residential Rate Design) and 13 (Rate Design) should be updated, as necessary. Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or an explanatory note. Such notes should be documented on Sheet 14 Tracking Sheet and may also be included on other sheets in the RRWF to assist understanding of changes.

In addition, please file an updated set of models that reflects the interrogatory responses.

Hearst Power:
HPDC confirms that a revised suite of models has been filed along with these responses and that the middle column of the RRWF has been updated to reflect the proposed changes.

Summary of Changes to models:

Load Forecast Model:

1) **Update WS consumption. 2010-2014 in the initial application was based on the inputs as approved in HPDC's 2015 Cost of Service. In responding to IRs related to the forecast (wholesale vs retail), HPDC performed an in-depth review of its historical monthly invoices and found errors in the reporting by previous management. Therefore, HPDC updated its wholesale to reflect accurate readings.**
2) **Although it did not change its regression results significantly, HPDC removed its MicroFit and Fit consumption from its wholesale prior to running its regression**
3) **In using 2020 actuals, HPDC dropped 2010 from its regression and used a 10-year regression based on 2011-2020 to determine its 2021 load forecast.**
4) **HPDC update its days per month, specifically in February to reflect leap years.**
5) **HPDC removed the manual recalculations based on averages of "outliers".**

6) **In rerunning its forecast, HPDC opted to include "Customer Count" as it slightly improved the regression results.**

Demand Profile:
1) **Update model to reflect changes in the LF**

RTSR Model:
1) **Update model to updated UTRs**

Rates model/Chapter2 Appendices/RRWF:
1) **Update all affected worksheets with 2020 actuals,**
2) **Update Depreciation expenses to reflect update in CapEx**
3) **Update Cost of Power based on revised RTSR rates**

PILS:
1) **Update model to reflect revised Rate Base**
2) **Update bridge year additions to reflect actuals**

Cost Allocation:
1) **Update weighting factors to correct no input billing and collecting factor for StreetLights**
2) **Update Revenue tab to reflect revised kW for customers receiving their own transformer allowance**
3) **Update Customer tab to reflect changes in the LF and to remove customers which own their transformers**
4) **Update number of devises for streetlights populating primary and line transfer inputs**
5) **Updated Meter Capital and Meter Reading to reflect meters for GS > 50 and Intermediate meter info.**
6) **Updated Demand Data tab to factor revised line transformers**

LRAMVA/DVA:
1) **Update balances in 1568 based on revisions to LRAMVA model**

LRAMVA/DVA:
1) **Update Bill Impacts model accordingly**

1-Staff-2

Ref: Exhibit 1, Page 9
Hearst Power states in the application that:

> Hearst Power Distribution Co. Ltd. ("Hearst Power") has applied to the Ontario Energy Board to increase its electricity distribution rates effective

May 1, 2021. If the application is approved, a typical residential customer of Hearst Power will see increase of $3.87 per month and a typical General Service < 50kW customer of Hearst Power will see a decrease of approximately $5.18 per month. (ref: Exhibit 8 for detailed bill impacts)

Per the bill impact model filed in Exhibit 8, staff notes that the total bill impacts for Hearst Power for a typical residential customer is an increase of $4.69 and an increase of $7.29 for a typical General Service < 50kW customer.

a) Please explain the discrepancy between Exhibit 1 and Bill Impact provided in Exhibit 8.

Hearst Power:

a) The plain summary of the application was sent out in advance of the filing. This was done to allow the customer enough time to ask questions or provide comments. The discrepancy is due to updates between the filing of the two documents; some are related to the OEB changes while others are simple corrections that were done shortly before the application was filed.

1-Staff-3

Ref: Exhibit 1, Page 54
Ref: Exhibit 2, Page 07
In summarizing the application in Exhibit 1, Hearst Power states in Table 1 – 2021 Parameters vs 2015 OEB Approved Parameters that the 2015 rate base is $1,502,387 and 2021 rate base is $1,554,293. In addition, the average fixed asset value for 2015 is $828,703 and $693,730 for 2021.

OEB staff notes that in Exhibit 2 in describing rate base in Table 1 – Test Year Rate Base, Hearst Power states that the 2015 OEB approved rate base is $2,176,072 and the 2021 rate base is $2,414,857. Moreover, the average gross fixed assets value for 2015 OEB approved is $4,980,312 and $2,941,929 for 2021.

a) Please confirm which rate base and average fixed asset values are correct. Update any changes as required.

Hearst Power:

There was a formula error in the table at page 54. Please see the corrected table below. (Please note that the update reflects the changes identified at Staff-1.)

	NEWGAAP	MIFRS	
Particular	2015	2021	Diff
Long Term Debt	4.54%	2.85%	-1.69%

Short Term Debt	1.65%	1.75%	0.10%
Return on Equity	9.19%	8.34%	-0.85%
Weighted Debt Rate	4.35%	2.78%	-1.57%
Regulated Rate of Return	**6.28%**	**5.00%**	**-1.28%**
Controllable Expenses	$1,019,224	$1,207,448	$188,224
Power Supply Expense	$10,030,148	$8,001,937	-$2,028,211
Total Eligible Distribution Expenses	$11,049,372	$9,209,384	-$1,839,987
Working Capital Allowance Rate	7.50%	7.50%	0.00%
Total Working Capital Allowance ("WCA")	**$828,703**	**$690,704**	**-$137,999**
Fixed Asset Opening Bal Bridge Year	$4,980,312	$2,950,031	-$2,030,281
Fixed Asset Opening Bal Test Year	-$3,632,943	-$1,220,157	$2,412,786
Average Fixed Asset	$1,347,369	$1,729,874	$382,506
Working Capital Allowance	$828,703	$690,704	-$137,999
Rate Base	**$2,176,072**	**$2,420,578**	**$244,507**

1-Staff-4

Ref: Exhibit 1, Page 98

In discussing the customer engagement, Hearst Power states that it did not reach out to inform its customers of the proposals being considered for inclusion in the application and the value of those proposals to customers. OEB staff also notes that Hearst Power states that the idea of a Town Meeting was explored but based on history, there is usually very little interest from the customers in attending such meetings.

a) Please explain how the planning and pacing of the capital projects proposed reflect customer preferences.

   Hearst Power: Capital projects proposed are in line with customer concerns the most important of which are service quality/power interruption and pricing. By replacing end of life poles, Hearst Power will alleviate possible exposure to serious reliability and power outages due to pole failures. Additionally, by completing the proposed capital work, Hearst Power can reduce the need to perform ongoing reactive repairs to its assets, repairs that, over time, are more expensive the actively replacing vulnerable assets.

b) Please clarify if Hearst Power is planning any customer engagement activities in the future to inform the customers of the proposals being considered for inclusion in the application.

   Hearst Power: When the new rates are approved, Hearst Power will publish them online.

c) Please explain the historical events that led to Hearst Power reaching the conclusion that there is very little interest from customers to attend Town Meeting.

Hearst Power: During this Emergency COVID-19 period, customers do not participate in indoor meetings as it is not advisable by our Health Unit. All Town meetings are completed virtually and information for comments or questions is provided.

d) If Hearst Power has done Town Meetings in the past, please provide the percentage of customers who attended the meeting.

Hearst Power: In the year 2016, Hearst Power and IESO representatives organized a public meeting. It took a full day for the IESO reps to travel each way. Even though the meeting was advertised in the local newspaper and on our website, no customers attended.

Note: Due to the very positive feedback in the Customer Satisfaction Surveys, Hearst Power believes that customers are generally happy and don't generally see the need to intervene.

1-Staff-5

Ref: Exhibit 1, Page 104

In discussing the customer satisfaction survey, Hearst Power states that it surveyed 503 of its residential, small and medium business customers in 2019.

a) Please clarify if Hearst Power performs any surveys for other customer classes (i.e. General Service >50 to 1499 kW and Intermediate).

Hearst Power: GS>50 services are considered "medium" therefore, yes they are invited to complete the survey. Intermediate customers (2 wood processing mills) are not invited to file the Customer Satisfaction Survey; instead, regular discussions are done with these two customers including scheduling repair work (power outage) that will fit their schedule, Class A billing changes, changes in Power Demand and Power factors, etc.

1-Staff-6

Ref: Exhibit 1, Page 112

In the Overall Scorecard for Hearst Power, OEB staff notes that the System Reliability – Average Number of Times that Power to a Customer is Interrupted has consistently been higher than the Distributor Target value from 2016 to 2019.

a) Please provide reasons for the higher values. In addition, clarify how Hearst Power is planning to improve reliability performance.

Hearst Power:

As described in the Distribution System Plan (Exhibit 2, page 85) "*HPDC's 5-year average SAIDI is 2.73 and its' 5-year average SAIFI is 1.40 not including Loss of Supply interruptions. These ratios 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. HPDC works to maintain, and possibly decrease, these levels as indicated in the following section.*"

To clarify, Hearst Power has increased scheduled interruptions due to more and more pole changes required since 2015 due to the aging infrastructure and asset analysis. To offset the increase in power interruptions required, Hearst Power is installing in-line switches and trying to connect circuits together where possible to back feed electricity and decrease the scope of required power outages (reducing the number of affected customers) when completing a pole change.

b) Please provide reasons for the value of 4.33 in 2017 for System Reliability – Average Number of Hours that Power to a Customer is Interrupted.

Hearst Power: 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 the other years in that same table.

1-Staff-7

Ref: Exhibit 1 – Administrative Documents, Business Plan, Section 7.2

Section 7.2 of Exhibit 1 – Administrative Documents discusses various expenses and revenues and their impacts on load forecasting and revenue requirements. In this section, the following is stated:

> Another external factor contributing to the increase is the discontinuation of CDM and Affordability programs which in previous years, diverted distribution expenses (Labour) to tend to these activities which are recorded under "non-rate regulated" accounts.

a) Please explain how operating and labour costs have increased as a result of discontinuing CDM and Affordability programs.

Hearst Power:

With CDM and Affordability Fund task added to the workload in certain years, some employees had a percentage of their work related to completing non-rate regulated work. For example, if an employee completed 2 hours of non-rate regulated work in a day, these 2 hours of work were taken out of distribution expense as this employee was not performing distribution related work. The actual labor expense was not increased or reduced overall but it is proportionally classified under “distribution” or “non-rate regulated” which may cause one section to be higher, or lower, from one year to another. With CDM and Affordibility Programs terminating employees who were perfoming CDM and/or aAfordability Program work during normal work hours returned to performing mostly or entirely distribution related work.

1-Staff-8

Ref: Exhibit 1, Appendix 2-A
Ref: Exhibit 6, Page 7
In Appendix 2-A of Exhibit 1, Hearst Power states under List of Requested Approvals a service revenue requirement of $1,233,292.

OEB staff notes that in Exhibit 6 in describing rate base in Table 3 – 2021 Test Year Revenue Requirement, Hearst Power states that the service revenue requirement is $1,468,673 and base revenue requirement is $1,233,291.

a) Please confirm which service revenue requirement value is correct and update any changes as required.

   Hearst Power: Both statements are true and correct. The difference is that $1,468,673 is the Revenue Requirement and that $1,233,291 is the <u>base</u> revenue requirement. The <u>base</u> revenue requirement includes the deduction of “revenue offsets” which are not collected in distribution rates. (HPDC notes that the revenue requirement has been updated to reflect the changes identified at Staff-1.)

1.0-VECC-1

Reference: Exhibit 1, page 14

a) Please confirm (or correct) that subsequent to this application, if approved as filed, would be to move Hearst from the stretch factor cohort of 2 to cohort 1.

   Hearst Power:

   a) According to the OEB Benchmarking model which HPDC assumes mimics the mechanics of the PEG calculations, the statement is accurate in that if the application were approved as filed, the resulting cohort would be group 1.

1.0-VECC-2

Reference: Exhibit 1, page 14

a) Where are the Powerline and Hydro One crews which Hearst relies upon located?
b) How often are these crews typically called upon in a given year?

Hearst Power:

a) Reference to Exhibit 1, page 14 cannot relate to question, possible clarification may be needed if the following response does not address this question → Hearst Power Powerlinemen are located in the Town of Hearst, within Hearst Power's geographical limits. The closest Hydro One Distribution Powerlinemen crew is located in Kapuskasing, 90 km from the Hearst Power's geographical limits and the Hydro One Transmission Powerlinemen crew is located much further away as sometimes the repair crew is coming from Sudbury which is located 560 km from Hearst Power's geographical limits. Therefore, outages on the H1 transmission line take much more time to repair.

b) Hearst Power employees (Powerlinemen) work 8 hrs per day, 5 days a work and can be called upon, during outside of regular hours, around 20 times per years, not including scheduled overtime work for pole replacement on weekends.

Hydro One Powerlinemen are very rarely called upon to assist the Hearst Power crew, only in significant emergencies where there would be a major issue.

Hydro One Powerlinemen are called upon to work on their own poles and wires infrastructure located within the Hearst Power geographical area, at any time there is a Hydro One pole failure or power outage within these limits. It is a working relationship between Powerline crews that, in the event that a fault is found on the other party's infrastructure, the other party is notified.

1.0-VECC-3

Reference: Exhibit 1, page 112

a) Please update the Hearst Power Scorecard to include 2020 data.

Hearst Power:

a) As filed

	2018 (History)	2019 (Bridge)	2020 (Test Year)	2021	2022	2023
Cost Benchmarking Summary						
Actual Total Cost	1,495,622	1,499,868	1,502,237	1,488,945	1,491,549	1,511,527
Predicted Total Cost	1,850,658	1,941,797	1,987,952	1,949,776	1,992,169	2,034,843
Difference	(355,036)	(441,929)	(485,715)	(460,831)	(500,620)	(523,316)
Percentage Difference (Cost Performance)	**-21.3%**	**-25.8%**	**-28.0%**	**-26.96%**	**-28.94%**	**-29.73%**
Three-Year Average Performance			-25.0%	-26.93%	-27.97%	-28.55%
Stretch Factor Cohort						
Annual Result	2	1	1	1	1	1
Three Year Average			1	1	1	1

b) Revised for 2020 Actuals

	2018 (History)	2019 (Bridge)	2020 (Test Year)	2021	2022	2023
Cost Benchmarking Summary						
Actual Total Cost	1,495,622	1,499,868	1,503,097	1,489,687	1,492,256	1,512,202
Predicted Total Cost	1,850,658	1,941,797	1,984,173	1,942,075	1,984,300	2,026,806
Difference	(355,036)	(441,929)	(481,076)	(452,388)	(492,044)	(514,604)
Percentage Difference (Cost Performance)	**-21.3%**	**-25.8%**	**-27.8%**	**-26.52%**	**-28.50%**	**-29.29%**
Three-Year Average Performance			-25.0%	-26.70%	-27.59%	-28.10%
Stretch Factor Cohort						
Annual Result	2	1	1	1	1	1
Three Year Average			2	1	1	1

1.0-VECC-4

Reference: Exhibit 1, page 115

a) Please update Table 19 – Profit and Loss – to include actual 2020 data.

Hearst Power:

a) As revised with 2020 Actuals

	Actual	Actual	Projected

	2019	2020	2021
Utility Income	**-186,535**	**84,223**	**80,750**
Gross Fixed Assets (year end)	2,568,179	2,756,281	3,143,781
Capital Expenditures (additions)		**188,103**	**387,500**
	##	##	##
Accum Depreciation	-1,018,834	-1,149,939	-1,290,374
Remove Non-Distribution Assets (2180)			
Net Fixed Assets	1,549,344	1,606,342	1,853,407
Average Net Fixed Assets	1,520,525	1,577,843	1,729,874
	2,281,348	2,264,051	2,420,578
Utility Rate Base	2,281,348	2,264,051	2,420,578
Deemed Equity Portion of Rate Base	912,539	905,620	968,231
Income/(Equity Portion of Rate Base)	-8.18%	3.72%	3.34%
Indicated Rate of Return	12.39%	6.48%	5.00%
Approved Rate of Return	6.28%	6.28%	5.00%
Sufficiency / (Deficiency) in Return	6.11%	0.20%	0.00%
Net Revenue Sufficiency / (Deficiency)	**139,358**	**4,474**	**0**

	Actual	Projected	Projected
WCA	**2019**	**2020**	**2021**
Cost of Power	9,042,549	8,060,876	8,001,937
WCA Rate	7.50%	7.50%	7.50%
	760,822		
	Actual	**Projected**	**Projected**
Derivation of Utility Income	**2019**	**2019**	**2020**
Operating Revenues			
Distribution Revenues	1,239,660	1,133,597	1,233,578
Other Revenue	286,521	255,722	235,382
Total Operating Revenues	**1,526,181**	**1,389,319**	**1,468,960**
OM&A Expenses	1,101,747	1,088,558	1,207,448
Depreciation & Amortization	108,885	131,105	140,435
Property and Taxes	0	0	0
Total Costs & Expenses	**1,210,633**	**1,219,663**	**1,347,883**
Deemed Interest Expenses	96,081	62,433	40,327
Total Expenses	**1,306,714**	**1,282,096**	**1,388,210**
Utility Income before Income Taxes / PILs	**219,467**	**107,223**	**80,750**
PILs / Income Taxes	34,921	23,000	0
Adjustments for FS purposes (donations)	-2,000		
Utility Income	**186,546**	**84,223**	**80,750**
	-186,535	**0**	

Exhibit 2 – Rate Base and Distribution System Plan

2-Staff-1

Ref: Exhibit 2, Page 8

In explaining the Rate Base Trend, Hearst Power states that:

> The Rate Base for the 2021 Test Year has increased by $105,276 over the last actual 2019, and $238,785 over the last OEB Approved Rate Base.

OEB staff notes that in Table 2 – Rate Base Trend, the increase from 2019 to 2021 is from $2,281,348 to $2,414,857, which is a difference of $133,509.

a) Please confirm which amount is correct and update any changes as required.

Hearst Power:

a) HPDC confirms that the difference between the 2021 rate base and 2019 is $133,509 and not $105,276. The value of $105,276 comes from the difference of 2019 vs the last OEB Approved Rate. The statement will be updated.

2-Staff-2

Ref: Exhibit 2, Page 38

OEB staff notes that the 2015 OEB-approved System Renewal capital expenditure for pole replacement was $70,000. However, in 2015, 2017, 2018, 2019 and 2020, Hearst Power spent between $82,842 to $110,636. OEB staff notes that in its 2015 Cost of Service, Hearst Power estimated to replace 20 poles a year.

a) Please explain why the spending for pole replacement was higher for past few years compared to the OEB-approved amount of $70,000.
b) What was the final amount spent in 2020?
c) How many poles were replaced each year from 2015-2020?
d) Please provide the average installed cost per pole replacement achieved by Hearst Power over the 2015 to 2020 time period. In addition, please provide the cost per installed pole replacement that Hearst Power is projecting each year of the 2021 to 2025 time period.
e) Please provide the methodologies Hearst Power is anticipating that will allow it to attain the greatest efficiencies for pole replacement in carrying out this work (e.g. improved work methods, different workplace setups, batch replacements at nearby locations, improved equipment, newer types of tools).

Hearst Power:

a) Pole replacement is determined by condition assessment during pole inspection surveys. The 2014 survey used in the last Distribution system plan (2015) identified 126 poles requiring replacement due to deteriorated condition for the period of 2015 to 2019. As described in the DSP, Hearst Power infrastructure is aging and will continue to require renewal to avoid dangerous pole failures. To put this in perspective, in the 2019 pole inspection survey included in the DSP, 48% of the total poles were identified as being 60 years old or more and 9% was identified as in poor condition, whereas in the 2014 pole survey included in the last COS, 57% of the total poles were identified as being 60 years or more and 14% was identified as being in poor condition. Hearst Power owned 1,545 poles in 2019.

Note: While pole replacements are mainly completed in response to condition assessments some are, obviously, completed due to accidental collisions or other external sources

b) In 2020, $137,725 was capitalized for pole replacements.

c)

Year	Pole replaced	Cost	Cost per pole
2015	30	$ 110,612.00	$ 3,687.07
2016	23	$ 69,251.00	$ 3,010.91
2017	29	$ 101,232.00	$ 3,490.76
2018	31	$ 82,842.00	$ 2,672.32
2019	29	$ 88,532.00	$ 3,052.83
2020	37	$ 137,725.00	$ 3,722.30
2021	35	$ 100,000.00	$ 2,857.14
2022	40	$ 112,200.00	$ 2,805.00
2023	40	$ 114,500.00	$ 2,862.50
2024	40	$ 116,800.00	$ 2,920.00
2025	40	$ 119,100.00	$ 2,977.50

Year	Pole replaced (includes end of life poles, accidented poles and customer requests)
2015	30
2016	23
2017	29
2018	31
2019	29
2020	37

d)

Note that the year 2020 included more complex poles and there was no contributed capital received from third parties (insurance companies, pole attachers, etc) or customers.

The replacement cost per pole varies greatly in any given year due to the following factors:

- Pole location (Downtown vs rural road)
- Soil bearing
- Pole height & class required
- Required site finish and pole protection (ie: asphalt or granular material, traffic barriers, pole supporting equipment, etc)

Pole replacement cost can easily vary between $1,500 to $5,000.

e) Hearst Power is organizing its 2021 to 2025 pole replacement in series of nearby locations to achieve efficiency. A new bucket truck is ordered for 2021 and it will be more efficient to operate and maintain when compared to the the 1995 bucket truck currently in service. The pole replacement schedule is also developed taking into consideration a mixture of less expensive poles and more expensive pole so that there is not a significant increase in capital pole cost from one year to another. These efficiencies have been captured in the yearly pole replacement budget as a reduced forecasted pole replacement cost was used.

2-Staff-3

Ref: Exhibit 2, Page 39
Ref: Exhibit 2, Distribution System Plan, Page 32
In explaining the replacement of Line Transformers, Hearst Power states that:

> Transformers replacement is determined by a "run to failure" practice, therefore they are being replaced on an as-needed basis. As set out in the DSP at section 2.4 starting in the year 2022, Hearst Power plans to start proactively replacing 5 to 10 transformers per year based on age and

> condition assessments, in order to renew these assets and not require a significant number of replacement in one year.

OEB staff notes that the OEB approved amount for Line Transformers was $6,017 in 2015. However, Hearst Power has spent over this amount for the last five years. The projected amounts for 1850 – Line Transformers – Replace Transformers is also over $30,000 for most of the next five years.

In explaining Asset Lifecycle Optimization, Hearst Power states that:

> Overhead transformers are inspected visually as part of the Distribution System Code requirements and identified problems are corrected. Underground transformers are inspected per the Distribution System Code requirements. The inspection includes looking for rust which is cleaned off and painted at a later time, and checking the concrete base for cracks, etc. that create public safety and transformer stability issues.

a) Considering a new proactive approach of transformer replacement, please clarify the factors Hearst Power is planning to use to determine whether a transformer requires replacement, other than visual inspection.
b) Please explain the benefits in cost and reliability from switching to proactive replacement of transformers.

Hearst Power:

a) Hearst Power replaces transformers based on condition assessment with <u>age</u> also being a factor for this new proactive approach.

b) The main driver for the proactive replacement of transformers is to lessen the risk of plant failing in service and creating long outages for customers (the “benefit in reliability”) and added O&M costs for the utility (the “benefit in cost”). This is intensified if there are simultaneous failures if the failures are the result of weather stressors such as high temperatures or power disturbance on the Hydro One distribution station (high/low voltage). HPDC only has one line crew and a limited stock of transformers therefore responding to multiple blown transformers at once can be challenging and certainly more expensive.

   In other words, the proactive approach is proposed to start replacement of the very large quantity[1] of >50 years old transformers currently in-service. This proactive approach helps develop a cycle that would renew transformer assets and maintain power stability at the lowest cost possible over the long term.

   [1] Refer to Exhibit 2, page 94

2-Staff-4

Ref: Exhibit 2, Page 43

In explaining the gross asset variance analysis for General Plant in Exhibit 2, Hearst Power states that:

> Hearst Power owns 2 pickup trucks. In 2018, one pickup truck was planned to be replaced in the same year a no-fault accident with the other pickup truck occurred and the damages were so extensive that it needed to be replaced. The result was that the two pickup trucks replacement caused a material expenditure of $61,484.

a) Did Hearst Power receive any compensation from its auto insurance policies for the no-fault accident?
b) If so, are the compensation amounts accounted for in the capital cost of the pickup truck?
c) Please provide information on the cost of each pickup truck.

Hearst Power:

a) Yes, Hearst Power received $37,559.69 (including HST) in compensation from its auto insurance policies.

b) No, the compensation amount is not accounted for in the capital cost of the pickup truck, it is accounted under Account #4355 – Gain on Disposition of Utility & Other Property.

c) Pickup purchases were based on RFQ submitted to dealers (minimum 3 quotes required). The following pickup were purchased at different times:
    1. Chevrolet Silverado – $29,083.75
    2. Ford XLT – $32,400.00

2-Staff-5

Ref: Exhibit 2, Page 63
Ref: Exhibit 8, Page 16

In explaining the cost of power in Exhibit 2, Hearst Power states that:

> The Wholesale Market Service (WMS) rate used by rate-regulated distributors to bill their customers shall be $0.0032 per kilowatt-hour, effective January 1, 2019. For Class B customers, a CBR component of $0.0004 per kilowatt-hour shall be added to the WMS rate for a total of $0.0036 per kilowatt-hour. For Class A customers, distributors shall bill the actual CBR costs to Class A customers in proportion to their contribution to peak.

OEB staff notes that in Exhibit 8 in describing Wholesale Market Service Rate, Hearst Power states that

The order states that the WMS rate used by rate-regulated distributors to bill their customers shall be $0.0030 per kilowatt-hour, effective January 1, 2020. For Class B customers, a CBR component of $0.0004 per kilowatt-hour shall be added to the WMS rate for a total of $0.0034 per kilowatt-hour.

a) Please confirm which WMS rate Hearst Power used for this application and update changes as required.

Hearst Power:

a) The cost of power is calculated as such

Wholesale Market Service	**Units**	Volume	Rate	$
Class per Load Forecast				
Residential	kWh	24,631,175	0.0030	73,894
General Service < 50 kW	kWh	11,506,833	0.0030	34,520
General Service > 50 to 4999 kW	kWh	25,337,701	0.0030	76,013
Intermediate	kWh	21,042,708	0.0030	63,128
Sentinel	kWh	10,114	0.0030	30
Street Lighting	kWh	475,496	0.0030	1,426
other				-
other				-
other				-
SUB-TOTAL				249,012

Class A CBR	**Units**	Volume	Rate	$
Class per Load Forecast				
Residential	kWh			-
General Service < 50 kW	kWh			-
General Service > 50 to 4999 kW	kWh			-
Intermediate	kWh			-
Sentinel	kWh			-
Street Lighting	kWh			-
other				-
other				-
other				-
SUB-TOTAL				-

2-Staff-6

Ref: Exhibit 2, Distribution System Plan, Pages 8, 19

Regarding the three feeders that are utilized in the Hearst Power service area (M1, M2, and M3) please state:

a) The ownership of each feeder.
b) Number of connected Hearst Power customers on each feeder.
c) The full load capacity of each feeder in MW.
d) The load transfer capability of each feeder in MW and the feeder to which the load could be transferred.

Hearst Power:

a) Ownership: M1, M2 owned by Hydro One. M3 owned by HPDC within the HPDC service territory.

b) Customers connected: M1 – 427; M2 – 1944; M3 - 394

c) The M1 and M2 feeders are owned and operated by Hydro One. Also, Hearst TS is owned and operated by Hydro One. As such HPDC does not have specific information about the full load capacity of each feeder. It is aware that within the HPDC service territory the feeders are a combination of 3/0 ACSR and 1/0 ACSR. The feeder configuration is determined by Hydro One because of their operating control over the line. This is also determined by Hydro One because their customers are downstream from the HPDC loads. Hence HPDC has no control over the feeder configuration. HPDC has requested the information asked for in this question and the response from the Hydro One staff looking after the HPDC account was that it would take several weeks to get the information to HPDC. Therefore, as of the date of the IR responses, Hearst Power does not have the exact MW value for each feeder as requested by OEB.

d) Answered in (c) above.

2-Staff-7

Ref: Exhibit 2, Distribution System Plan, Pages 8, 19

Regarding the three feeders that are utilized in the Hearst Power service area (M1, M2, and M3) please state:

a) What kind of protective relays are used for each feeder at Hearst Transformer Station (TS)?
b) What type of overall protection schemes are utilized for each feeder at Hearst TS?
c) If auto reclose protections are utilized on any feeders at Hearst TS and, if so, which feeder(s).

d) If reclosers are utilized on any of the three feeders themselves and, if so, which feeder(s).

Hearst Power:

Hearst TS is owned and operated by Hydro One. HPDC is not the authority to provide accurate information about the station because it does not have the knowledge of nor the authority to distribute this information. The information provided here is based on our observation of system operation.

a) HPDC believes that they are solid state relays with timed overcurrent tripping and instantaneous tripping as well as having reclosing capability and reclosure blocking capability. HPDC has no knowledge of any additional capability they may have.

b) Other than what is provided in (a) above HPDC has no further information on the station protection. The HPDC system is protected by fuses at all laterals and fuses at all transformers. Where the M1 and M2 feeders leave the HPDL service area to feed other Hydro One customers there are metering units to be able to accurately generate wholesale bills for the HPDL power used and there are also reclosers to prevent feeder lockout if there are downstream permanent faults.

c) Answered in (a) above.

d) M1 and M2 at the point power leaves the Hearst service territory.

2-Staff-8

Ref: Exhibit 2, Distribution System Plan, Page 19

Regarding the three feeders that are utilized in the Hearst Power service area (M1, M2, and M3), please state:

a) The type and number of sectionalizing switches that are currently installed on each feeder.
b) The number of porcelain insulated lightning arrestors that are currently installed on the main feeder portion of each feeder.
c) The number of porcelain insulated lightning arrestors that Hearst Power is proposing to replace each year.

Hearst Power:

a) The following are installed: M1 – 2, M2 – 8, M3- 3. The types of switches may vary from a Chance ALTD0600R inline switch, one per phase, to an S&C Omni-Ruptor, 3 phase gang operated switch.

b) 99 so 33 locations for all three feeders combined. They are 3 phase laterals connected to the main feeder.

c)

Year	Number of locations
1	6
2	7
3	7
4	7
5	6

2-Staff-9

Ref: Exhibit 2, Distribution System Plan, Page 19
Given that there are various projects proposed in the DSP to improve system reliability, please provide an estimate for the improvements (defective equipment component) in both outage frequency and outage duration anticipated for each of the following initiatives:

a) Replacement of approximately 200 poles over a five-year period.
b) Replacement of all main feeder rural porcelain lightning arrestors that could cause total feeder outages over a five-year period.
c) Replacement of all porcelain cutouts directly connected to main feeders over a five-year period.

Hearst Power:

a) On page 43 it states the following:
Evaluation Criteria and Information Requirements for Each Project / Activity

Project -Pole Replacement

1. Efficiency, Customer Value and Reliability
a. The main driver for the pole replacement program is the risk of plant failing in service and creating long outages for customers and added O&M costs for the utility. This is intensified if there are simultaneous failures if the failures are the result of weather stressors such as high winds. HPDC only has one line crew to respond to these situations demonstrate.

If the right poles are being selected for replacement, I would expect no increase in poles that fail in service due to inadequate pole strength. This excludes poles that are struck and fail or catch fire and fail. On the other hand, if there are no poles that are failing due to inadequate pole strength (which appears to be the case from the outage statistics) I would not expect to have the system reliability improve. As stated in the DSP and as quoted above this is to prevent a deterioration of reliability performance caused by pole failures.

b) Porcelain lightning arrestors have been a problem in the industry for many years. They have worked in HPDC without major problems for many years. In the previous DSP they were identified as a problem based on actual failures. The focus was on the urban part of the distribution system for people safety reasons. This was completed. New failures occurred and these caused feeder outages. This project addresses this aspect. Since there are 99 arrestors connected to main feeders directly each with the possibility to cause a feeder outage and because the laterals are three phase and if a failure occurs all three arrestors will be replaced. Since the arrestor failure is "when it fails" and not if it fails there could be up to 33 feeder lockouts into the future each in the 3-to-5-hour duration range depending on a number of conditions. The point is that these faults are occurring now as random events that increase costs and interrupt planned work. Solving this defect will improve reliability somewhat but HPDC is not experiencing weekly failures that are causing disastrous reliability statistics. So, this is exercising prudence, good business sense and is being proactive in solving a problem before it causes more harm. HPDC also notes that this project is significantly below the materiality threshold.

c) The same logic as (b) above. In addition, this is a safety issue for crews operating these devices. Each switch is a potential outage or electrical flash accident. Safety is an imperative. With the switches replaced the system will be slightly more reliable.

2-Staff-10

Ref: Exhibit 2, Distribution System Plan, Page 20

In discussing smart meters, Hearst Power states:

> Hearst Power does not have SCADA or OMS so near real time use of the "last gasp" information can not be used to alert staff of an outage in near real time.

a) Has Hearst Power investigated any technology available to make use of "last gasp" information from smart meters for a abase courage alarm to notify of the occurrence and the location?

Hearst Power:

a) See page 20 and 21 of the DSP. HPDC is using the query capability of the customer system to identify when the meter stopped working. There are no alarms associated with this at this time because it is a database query report that is manually generated and not a monitoring feature of the customer system. HPDC has not pursued other ancillary equipment but did check if the existing systems could provide alarms.

2-Staff-11

Ref: Exhibit 2, Distribution System Plan, Page 22

Hearst Power states on page 22**:**

Hearst Power's Corporate goals are:

a) To deliver electrical power to the customers that meet the customers requirements.
   - o Reliably
   - o Affordably

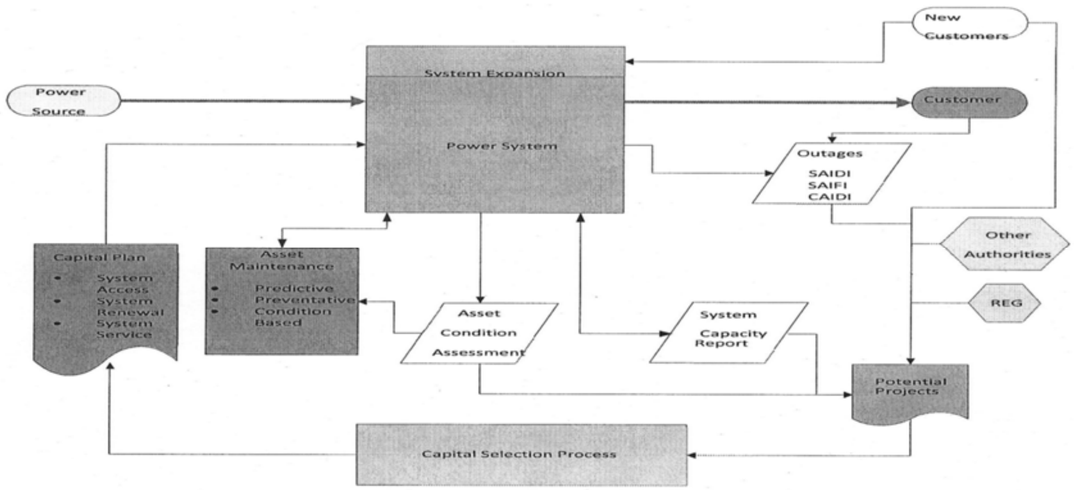
b) To remain financially capable of continuing delivering power to customers.

The Asset management objective is to achieve a low owning cost but maintaining safety and reliable performance that meets power delivery standards.

This is done by looking at the best long-term decision choosing between a repair or extend asset life action compared to replacement. The decision criteria is cost per year over the expected period of time the action is expected to be effective or if replaced the expected life of the asset as well as the impact on asset longevity, safety and reliability.

b) Below is the basic process Hearst Power is using with the asset management process

Graph 2
Asset Management Process Overview



Hearst Power Graph 2 “Asset Management Process Overview” omits the role of a number of significant items and activities which are part of the recognized Asset Management (AM)[1] process, e.g.:

i. indication that system renewal is the main part of the Hearst Power AM process;
ii. Asset Registry contents and inputs (including lists of assets managed);
iii. The individual steps in the process to arrive at the Asset Condition Assessment;
iv. Definition and role of Health Indices & steps included in establishing Health Indices;
v. Asset End of Life (EOL) criteria for individual assets;
vi. Inspections (their types and frequencies);
vii. Linkages among the inspections; and,
viii. Ranking, prioritization process.

a) Optimization of maintenance and capital programs is not mentioned as part of the AM objectives. Although reliability is mentioned it needs to be seen as one of the AM "tools" not the AM itself. Furthermore, formal linkages among the Hearst Power’s corporate goals, Hearst Power Asset Management objectives and Hearst Power assets are not indicated. Relative ranking of AM priorities is also not

[1] OEB Chapter 5, Section 5.3.1, states on page 13: “The distributor must provide the OEB and stakeholders with a high level overview of the information filed on a distributor’s asset management process, including key elements of the process that have informed the preparation of the distributor’s capital expenditure plan. The information provided should include but need not be limited to:
a) A description of the distributor’s asset management objectives and related corporate goals, and the relationships between them, including an explanation of how the distributor ranks asset management objectives for the purpose of prioritizing investments.
b) Information regarding the components (inputs/outputs) of the asset management process used to prepare a capital expenditure plan, including the identification and description of the data, primary process steps, and information flows used by the distributor to identify, select, prioritize and/or pace investments, for example:
• Asset register
• Asset condition assessment”

indicated. Please point to a section in this DSP, where the AM priorities, ranking and linkages can be found? If not, please explain whether you plan to initiate the preparation of such a document/process and indicate the intended time frame?

b) Has Hearst Power ever undertaken an independent third party of its AM program or an in-house evaluation? if so, what were the conclusions of this exercise?

Hearst Power:

In terms of the numbered section above please note the following:

i. There are numerous references in the DSP (5.2.1(c) Pg7, and (f); 5.2.3 (d) pg. 20; 5.3.2 (c) pg. 29; 5.3.3 (b) pg. 31 and others that indicate pole replacement (system renewal) is the major activity in asset management.
ii. The box "power system" includes all the equipment to move power from the source(s) to the customer(s). So the model does not show lists of assets but it is implied that all assets are part of the power system and that each asset that is assessed will have a unique identifier and a score representing its rating.
iii. This is included in the Asset Condition Assessment box. HPDC only does this for poles. This information is presented in Appendix E of the DSP.
iv. This is only used for poles. Other assets are run to failure.
v. Working definition for EOL. No longer capable of performing intended function. Eg. Burned out transformer, shattered porcelain insulator due to flashover,
vi. Inspections are part of Asset maintenance box. Description in 5.3.2 (a) pg. 30
vii. No reference.
viii. Part of the Capital Selection Process box. There is only one material line project so prioritization is none existent.

This point-by-point comment is to indicate that while the model presented contains the elements to do proper Asset management when looking beyond the box and using a general understanding of power systems. The model presented intended to be a high-level overview of the process.

a) HPDC does not have these documents at this time. It plans to develop and implement them to have them in place and functioning before the next DSP.

b) HPDC had a study done in 2013. It was to help establish the depreciation of assets and not for asset management. HPDC plans to conduct an Asset Management evaluation as part of (a) above and have the results for inclusion in the next DSP.

2-Staff-12

Ref: Exhibit 2, Distribution System Plan, Pages 24, 28, 32

Hearst Power states on page 28:

> The graphs[2] show that significant fractions of the installed plant, particularly the overhead plant, are 40, 50 and 60 years old. This is a concern and inspections are carried out to identify deteriorated plant that needs to be replaced. An inspection was carried out in 2009 and this inspection identified the assets that needed to be replaced. This plan has been completed in 2010 to 2014. In 2014, an inspection of the oldest pole assets [installed in the 1970's and earlier so 35 years and older] was conducted. In 2019, an asset survey was completed for all distribution assets no matter the age. The details of the latest inspection can be found in Appendix E.

Hearst Power states on page 32:

> Hearst Power's main distribution assets are poles, overhead wire, transformers, switches, and switch fuses as well as underground primary cable, transformers, and secondary cable.

a) Would you please explain whether each of the eight (8) asset types mentioned on page 32, as well as the lightning arrestors, cutouts, and switches mentioned on page 24, will be considered for Asset Condition Assessment, establishment of asset Health Indices and subsequently managed using established Asset Management principles and methods?

b) On page 28 Hearst Power states: "In 2019, an asset survey was completed for all distribution asset no matter the age." Please confirm whether this survey included all the Hearst Power distribution assets or whether it included poles only as shown in Appendix E? If it was for poles only, please explain whether you plan to initiate surveys of your other assets as part of Asset Condition Assessment and indicate the intended time frame for completion of the Asset Condition Assessment implementation?

Hearst Power:

a) These will be considered.

b) Current Asset Condition Survey mentioned was for poles only as shown in Appendix E. HPDC will investigate creating documentation for the systems and processes it uses as well as implementing its version of the USF asset assessment.

   HPDC is not convinced that the development of full-blown Asset Condition Assessment is a necessary or a financially prudent activity to be engaging in for a small utility like HPDC. The large formal systems are put in place mostly by large utilities with thousands of employees to ensure that there is a uniform

[2] Added footnote to explain the reference to the graphs: Graph 3: Age Distribution of Poles and Transformers; Graph 4: Age Distribution of Primary Overhead and Underground Conductor and Graph 5: Age Distribution of Secondary Conductor

standard of assessment and procedure that results in uniform performance to the customers and the share holders and regulators. In a small utility like HPDL with 7 employees (4 field + 3 office) the issue of common vision and uniformity of action is vastly different. Although, HPDC may not use all the assets analysis techniques referred above, not because the financial or reliability results are troubling, but because HPDC believes it would be an operationally ineffective use of rate payers' money. HPDC is not against the reports produced by Metsco or Kinetrics, but rather hesitant to spend rate payer's money on consultants as the pool of funding is very limited for small utility like HPDC.

HPDC will absolutely investigate this point raised by the OEB further and further expand the current in-house asset condition assessment to include more than poles.

2-Staff-13

Ref: Exhibit 2, Distribution System Plan, Pages 30, 33, 99, 100, 101

Hearst Power states on page 30, **"**Regular vegetation management. Based on a regular cyclical (3-year) geographically based schedule as well as input from the routine inspections."

Hearst Power states on page 33, "For Hearst Power, end of life pole replacement is the only material system renewal spending item currently and for the foreseeable future."

Hearst Power states on page 99, **"**Hearst Power has decided to use the following factors and rating for each factor:**"**

Hearst Power states on page 100, **"**To come up with a single value each of the factors A to G are weighted equally relative to the other factors.**"**

Hearst Power states on page 101, **"**Hearst Power used the above criteria and surveyed 1545 poles that have been in service. The criteria for replacement are a rating of 17 or lower. The lower the rating the poorer the pole condition is.**"**

a) Vegetation management occurs on a regular basis and on inputs from routine inspections. Has Hearst Power analyzed the effectiveness/adequacy of existing vegetation management in limiting outages and asset damage from storms? If so, please point to (or describe) these efforts. In particular, would more frequent and aggressive tree trimming be cost-effective in mitigating outage and asset damage potential?
b) With regard to the Hearst Power statement on page 33 about replacing end of life assets, please refer to the Hearst Power AM investment objectives and to the list of asset types managed included in the DSP. Please advise whether there are Hearst Power AM governance documents (i.e. policy, strategy, asset

management plan) which include end of life (EOL) criteria, criteria descriptions and EOL measures for each asset managed and point to this discussion.

c) With regard to Hearst Power statements on pages 99 and 100, please explain the reasons for selecting these particular factors and the basis used to determine equal weighing to each factor? Also, please explain whether data was analyzed for correlations between the factors and whether Hearst Power's system of pole assessments was compared with "expert judgement" using combined assessments of multiple experts?

d) With regard to Hearst Power's statement on page 101, there is no mention of the following:

   i. With regard to Hearst Power's rationale to select rating 17 or lower as the criterion for pole replacement, please provide Hearst Power's rationale to select the rating 17 or lower as the criterion? In particular, is this adequate to ensure the necessary replacement rate for the poles, or was it selected to be within a predetermined budgetary allowance?

   ii. Please confirm if Hearst Power's effort to incorporate industry best-practice and lessons learned is part of the Hearst Power's AM process and explain (or point to) specific efforts to share experience (and data) on asset performance with neighboring utilities. Also, please explain whether, as part of the preparation of poles assessments, you consulted recognized, authoritative and quantitative guidance such as, "Asset Depreciation Study for the Ontario Energy Board" prepared by Kinectrics Inc., Report No: K-418033-RA-001-R000 dated July 8, 2010. If so, please describe the assumptions and interpretations you made to categorize the Hearst Power asset types and their service conditions?

Hearst Power:

a) Appendix B of the DSP lists all the outage information. In addition, information was requested and provided for the complete outage information for 2020. This was not included in the DSP because the DSP was submitted before the end of 2020.

   The following are the updated outage tables reflecting the 2020 full year information.

Table 2: Customer - Hours by Cause

		Year					
Category	**Category Description**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
0	Unknown	17	149	2196	38	0	0
1	Scheduled	3485	2133	8185	2898	5036	1842
2	Loss of Supply	119098	2999	25047	5264	23508	29012
3	Trees	18	11	17	0	0	21
4	Lightning	0	25	23	142	0	9
5	Defective Equipment	283	664	225	3636	1529	6303
6	Adverse Weather	0	121	7	0	0	44
7	Adverse Environment	0	37	0	144	0	217
8	Human Element	0	0	1117	219	0	0
9	Foreign Interference	1729	2931	180	326	293	488
	Totals- All interruptions	124629	9070	36997	12667	30367	37936
	Total excluding “loss of supply”	5531	6071	11950	7403	6858	8925
	Total excluding “loss of supply” and “Scheduled”	2046	3938	3765	4505	1822	7082

Table 3: System Interruptions by Cause

		Year					
Category	**Category Description**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
0	Unknown	2	7	3	2	0	0

1	Scheduled	29	28	19	38	18	27
2	Loss of Supply	10	3	4	3	5	1
3	Trees	1	2	1	0	0	1
4	Lightning	0	2	2	2	0	1
5	Defective Equipment	12	12	9	15	9	9
6	Adverse Weather	0	2	2	0	0	1
7	Adverse Environment	0	2	0	1	0	2
8	Human Element	0	0	2	2	0	0
9	Foreign Interference	16	26	12	11	11	17
	Totals- All interruptions	70	84	54	74	43	59
	Totals –excluding " loss of supply"	60	81	50	71	38	58
	Totals –excluding "loss of supply" and "Scheduled"	31	53	31	33	20	31

Table 4: Customer Interruptions by Cause

		Year					
Category	**Category Description**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
0	Unknown	15	367	1819	4	0	0
1	Scheduled	924	1150	2114	2123	1213	607
2	Loss of Supply	17098	1271	8550	5930	8656	2763

3	Trees	3	11	1	0	0	25
4	Lightning	0	15	6	210	0	10
5	Defective Equipment	219	707	172	2921	1970	2142
6	Adverse Weather	0	17	4	0	0	30
7	Adverse Environment	0	25	0	90	0	87
8	Human Element	0	0	664	354	0	0
9	Foreign Interference	809	1227	107	96	65	504
	Totals- All interruptions	19068	4790	13437	11728	11904	6168
	Totals -not loss of supply	1970	3519	4887	5798	3248	3405
	Totals -not (loss of supply and Scheduled)	1046	2369	2773	3675	2035	2798

Table 5: Customers by Year

	Customers By Year					
Year	2015	2016	2017	2018	2019	2020
Customers	2771	2768	2763	2768	2760	2763

From the above data and Appendix B, the table below summarizes the relative magnitude of the vegetation caused outages in the context of the total outages in the same period.

Category	2015 to 2020 Vegetation caused outages	2015 to 2020 total outages
System Outages	5	199
Customer Interruptions	40	14,696
Customer-Hours Interrupted	67	23,158

Also, HPDC staff is meticulous in attributing the outage to the appropriate cause. So, if some equipment failed because of tree damage it would be classified to that cause and not as unknown or as equipment failure. These matters were addressed 5 years ago when that DSP was prepared.

A closer look at the data also shows that in 2016, Nov 19 the incident took place during freezing rain. Also, the incident in 2017 involved a tree on private property taking out the supply to the house and no one was home until the next day. HPDC does not trim on private property.

Given the above information HPDC is of the opinion that more frequent and aggressive tree trimming would not be cost-effective in mitigating outage and asset damage potential. Further, HPDC reviews the outages and outage statistics for all the system events to see if it can improve its maintenance program or initiate capital mitigation projects and takes action where this is cost-effective.

b) As indicated in a response earlier, HPDC notes that it does not have these documents.

c) HPDC has not performed the analysis that is being asked for. However, this model was created to address several matters. The first issue was how does HPDC assess poles so that it identifies those that would fail within the next 5 years. Next, HPDC wants to exclude poles that would not fail in the next 5 years. HPDC also wanted to have reproducible results regardless of which trained staff member did the assessment. HPDC wanted to use factors that where mostly visible or audible that had a bearing on the current condition and a predictive value to the future, so 5 to 10 years. This model did those things reasonably well. HPDC has not experienced broken poles in service that were classified as equipment failure. Hence, this approach has been cost-effective and performance effective. While HPDC does not have the *end of life (EOL) criteria, criteria descriptions and EOL measures for each asset managed* the outage data indicates that it is managing the pole asset effectively.

d)

i) A Bit of both. The number selected picks poles that are in the higher risk area compared to a higher number. Therefore, it effectively replaces poles that are in the poorest condition since they are tested every 5 years. Also, the pace of replacement appears to be adequate currently to keep costs relatively stable and is within the work capability of the crews. This is the kind of trial and error that is required with any program. In this case failures are not happening, which is a desired outcome, the cost is stable which is good, and the work is within the capability of the workforce. If there were pole failures in service, then the selection factor would need to increase to include more poles.

ii) HPDC is and has been independent for many years. It is a member of the USF and exchanges information. Because of its location it is not able to meet easily with other USF members nor is its service environment like the southern Ontario USF members. As a result, there is a certain independence and reliance on your own judgement that is necessary to be effective and cost effective. The neighbouring utility is Hydro One. They certainly have policies and Asset Management Plans etc. but when the 115KV line supplying HPDC goes down and the SCADA system for Hearst TS is down it still takes hours for an operator to get to Hearst TS from Sudbury to be able to turn on the power when the 115KV line is re-energized so that the whole town of Hearst is restored to power.

HPDC is not against policies and processes and learning and improving is necessary but approaches and methods need to be appropriate for the size of the organization. Size matters when considering the tools and methods to use. The tools to do asset management in a large utility need to be more defined, documented and often involve more automation. These tools are needed to provide uniformity of standards throughout the company, oversight of asset condition over the entire service area allowing effective corporate budgets to be developed. With a total staff of 7 employees HPDC does not need these systems to achieve these results. The scale of operation is just so much smaller that the tools used to run large utilities are not required to run an effective, efficient operation. But the thinking process is similar. For example, Graph 2 referenced in 2-Staff-11 takes the performance of the power system as it relates to outages and does the normal index calculations but as was done in the DSP also analyses the outages looking at worst performing feeders, what caused the performance and looks for ways to improve the performance. There are two ways this gets accomplished, first and this branch is not listed because it is a high-level diagram, what maintenance practices would help prevent to outage, second, what capital project would help prevent the outage. In a well-run, small utility this is the normal kind of analysis that takes place because employees care and because they owe it to the customers. Without this motivation and this mindset, you need to put a lot of rules (policies) in place to try to drive people to do the "right" thing.

2-Staff-14

Ref: Exhibit 2, Distribution System Plan, Page 29

Reference is made to the 2008 closure of forest products plant. Does that closure, and the related reduced load present an opportunity in the future to decommission/retire assets rather than replacing them?

Hearst Power:

No. The manufacturing plant that closed was supplied by a tap off the main feeder. The tap, line and the transformer were customer owned so not HPDL assets. The facility is still connected to the system but at a very low load. The feeder continues past the plant and supplies other customers.

The manufacturing plant is still used as a storage facility for lumber products.

2-Staff-15

Ref: Exhibit 2, Distribution System Plan, Page 30

"Risk is managed by being aware of the failures that occur on the power system and being aware of any safety consequences that are likely to accompany the failure."

a) Does the organization have a board-approved risk management program that works to identify risks before they occur?

Hearst Power:

No, HPDC does not have a designated board-approved risk management program. In order to better explain the statement referenced above Hearst Power would like to add the following context:

During an actual call out on for an accident involving logging trucks having knocked down pole and caused an outage, there are immediate safety issues, such for the safety of the drivers of trucks and the public in the immediate area. At the time the crew arrive on site, First Emergency Responders were too close to the downed power line and HPDC's response was to secure the area, then was to fix/ replace pole. This fixed the immediate outage and there was no further issue. But because Hearst Power recognized it was likely to be repeated they then went further and set up an education program for First Emergency Responders to have them take greater care in the electricity distribution plant. Additional, in areas where large vehicles have shown possibility or a tendency to hit electrical pole or any other infrastructure, Hearst Power staff immediately made arrangements to put up barriers to stop/prevent poles or other assets from being hit, thus managing risk.

2-Staff-16

Ref: Exhibit 2, Distribution System Plan, Page 35

Please describe the capital expenditure approval process, including confirming the role of the Board of Directors in approvals.

Hearst Power:

Yearly, capital expenditures are analyzed and proposed to HPDC management by the Leadhand/Operation Superintendent based on asset condition analyses, priorities, available manpower and outside factors (ie: customers, regulator, etc). The General Manager reviews the request and based on budget availability, the DSP planned capital work and the priorities, the General Manager recommends a Capital Budget to the HPDC Board of Directors for approval. The HPDC Board approves or refuses the proposed Capital Budget.

2-Staff-17

Ref: Exhibit 2, Distribution System Plan, Page 35

Hearst Power states that:

> Hearst Power has used this input to be frugal with its capital expenditures and as spread work to be done over several years to minimize the customer bill impact.

a) Has the risk been assessed that deferral of capital plans resulted in higher O&M costs than those that would have been incurred if assets were replaced more proactively? Given that HDPC's focus in on smoothing costs and meeting customer cost concerns, what are the parameters established to assess the trade-offs in deferring asset replacements (e.g., a more aggressive pole replacement)?

Hearst Power:

The Pole replacement program is the only material plant capital project for HPDC.

It is a fine line to be sensitive to customer requirements for low cost and inadequately do the things that need to be done to operate the utility wisely. Hearst Power believes that we are striking a good balance between these priorities. The customer survey information supports what the Utility is doing cost wise. The method used to select poles to be replaced is based on the actual condition of the pole and seeks to get the useful life out of the asset before replacing it. Hearst Power believes it is an effective way to relatively efficiently get operational data which when acted upon has decreased the number of pole structure failures in the normal operating environment including weather. If the rate of replacement had been increased substantially poles would have been replaced despite having useful life remaining, and would have required more labour and equipment and certain other tasks normally performed by staff such as vegetation management would not necessarily have been able to be completed using in house resources. This would have increased staffing, outside contracting costs or caused future reliability problems. As to the conjecture of increased O&M costs due to a slower capital replacement this may be true in such assets as cars for example; for new cars everything is supposed to work without O&M (except for oil etc.) and for old cars there is a never-ending list of things that need to be done, battery, brakes, water pump, timing belt, exhaust, radiator etc. But for a pole, if it is relatively good condition, it performs its function with minimal maintenance requirements. The only O&M is the inspection requirements under the DSC and pole testing, expenses which are not materially affected by increased pole replacements.

2-Staff-18

Ref: Exhibit 2, Distribution System Plan, Page 38

	5 years ending 2020	5 years ending 2025	Variance	Variance %
System Access	57	75	18	31.58%
System Renewal	557	723	166	29.80%
System Service	112	85	-27	-24.11%
General Plant	217	373	156	71.89%
Total	**943**	**1,256**	**313**	**33.19%**
System O&M	2,293	2,877	584	25.47%

As shown in the above table, derived from Table 18 in the DSP, capital expenditure is forecasted to increase by 33% and O&M is still forecasted to increase by 25% over the forecasted period.

a) As part of an informed Asset Management plan, could O&M costs be reduced through a more proactive capital expenditure approach?

Hearst Power:
No, the pole replacement program is the sole material line project and the O&M cost is not decreased by changing more poles (see answer to 2-staff-17 for details). In an essentially static plant size situation, the approximately same amount of O&M work is completed yearly, but the cost of materials and labour increase with inflation each year. The only way for O&M to decrease is if less work is done.

2-Staff-19

Ref: Exhibit 2, Distribution System Plan, Page 39
OEB staff notes that the forecasted Net Capital Expenditure for test year 2021 is $388,000, which is almost 200% of the forecasted average Net Capital Expenditure if $198,250 from 2022 to 2025.

a) Has Hearst Power considered deferring some capital projects from the test year to later years to better smooth out its capital spending over the term of the DSP?

Hearst Power:

In 2021 HPDL is replacing a bucket truck at a cost of (budget $265,000) now costing $255,000. Already in 2021 there are no other General plant capital items. They are deferred. System Access capital is driven by others. This is an estimate of what is anticipated based on current knowledge. The System renewal project is the pole replacement program which is required to maintain reliability performance. The System Service capital has deferred the new meters for one year. So, efforts have already been made. Replacing a bucket truck is a large investment and causes a big budget dollar bump when it happens. This is unavoidable in a small utility. Efforts are made to adjust but there is not the flexibility to significantly reduce already small, focused programs to the point where the expenditure bump can be smoothed significantly. So, Yes HPDL has considered deferring some capital and has done so to the extent it is reasonable.

2-Staff-20

Ref: Exhibit 2, Distribution System Plan, Pages 80,82,84
Tables 2-8 show that a consistent source of outages has been external causes. On page 84 the DSP notes that animals have contributed to these, especially in 2016. Has

Hearst Power reviewed options for protecting equipment against outages caused by animals?

Hearst Power:
In 2016, animals did contribute more than usual to outages. Exactly 11 crows and 2 squirrels died during that year by running/flying/playing on Hearst Power's 81 km of overhead distribution lines. Hearst Power has reviewed options for protecting against animals, particularly after the 2016 experience.

2.0-VECC -5

Reference: Exhibit 2, Table 3, page 10&11

a) Please explain how the variance of $128,855 in asset average balance that arose as between 2015 Board approved and 2015 actuals has "*a zero net impact on the resulting total rate base.*" Please also reconcile the figure of $128,855 with the $41,000 variance in capital spending in 2015 (i.e., actuals of 189k vs planned of 148k -as shown in Appendix 2-AB).

Hearst Power:

The reference to Rate Base was not in comparison to the 2015 Board Approved rate base but the 2015 Actual Rate Base of $2,308,259. The intent of the comment was to explain that the cleanup did not affect the 2015 Rate Base as it simply removed assets that were fully depreciated.

The variance between the 2015 actuals and 2015 Board approved is due to 2 reasons:

1. The IFRS transition which <u>included a general book cleanup</u>. The general book cleanup was to remove from the asset and accumulated depreciation account items that were no longer in service but has not been removed in prior years. Therefore, the same value was removed in both the asset accounts and the acc. depreciation accounts which resulted in a net zero impact. (ie: if an old disposed pickup truck was still accounted in asset account 1930 for the amount of 20,000$ and accounted in accumulated depreciation account 2105 for the amount of 20,000$, which the general book cleanup, both amounts were removed)
2. The figure of $128,855 represents the difference between the B.A. and the <u>average actual</u> balance from 2015 opening to 2015 closing. Please refer to document 2.0-VECC-5 attached.

2.0-VECC -6

Reference: Exhibit 2, page 11

a) Please explain why Table 4 shows a 2015 Board Approved variance of $144,265 which is different from the 2015 Board approved capital expenditures of $148,073.
b) Table 4 also shows 2015 additions $88,921 which is different than the continuity schedule additions for that year which is shown as $188,878. Please explain or reconcile?

Hearst Power:

a) and b) Please find below a corrected version of Table 4- 2015BA-2015 Var in Capex Additions

OEB	*Description*	*Additions*	*Additions*		
1611	Computer Software	$5,000	0	-$5,000	-100.00%
1830	Poles, Towers & Fixtures	$70,000	$110,636	$40,636	58.05%
1835	Overhead Conductors & Devices	$21,000	$26,604	$5,604	26.69%
1840	Underground Conduit	0	$104	$104	
1845	Underground Conductors & Devices	$5,431	$231	-$5,200	-95.75%
1850	Line Transformers	$6,017	$31,144	$25,127	417.60%
1855	Services	$11,000	$0	-$11,000	-100.00%
1860	Meters (Smart Meters)	$2,625	$792	-$1,833	-69.83%
1908	Buildings & Fixtures	$7,500	$10,574	$3,074	40.99%
1910	Leasehold Improvements				
1915	Office Furniture	$2,500	$1,440	-$1,060	-42.40%
1920	Computer Equipment - Hardware	$10,000	$7,353	-$2,647	-26.47%
1940	Tools, Shop & Garage Equipment	$7,000	$0	-$7,000	-100.00%
2440	2440-Deferred Revenues				
	Sub-Total	**$148,073**	**$188,878**	**$40,805**	

2.0-VECC -7

Reference: Exhibit 2, Table 4, page 11

a) Hearst significantly underspent its projected 2016 capital budget ($148k vs $89k actually spent). Please explain the reasons for this variance.

Hearst Power:

a) In 2016, Hearst Power received $29k in contributed capital from insurance companies and third parties which offset the $118k capital spending and dropped it to $89k.
The results were also impacted by the fact that Hearst Power had budgeted $16k for a new bucket truck jib and winch purchase to replace an old one but it was

later decided not to proceed as the crew, being only 3, were able to use only one jib and winch on the newest truck for the time being. Therefore, this purchase was deferred until a new bucket was to be purchased (2021). Additionally, in 2016, Hearst Power had one less Powerlineman during the majority of the construction season (May to Sept), therefore some projects had to be deferred to to 2017 (ie: in-line switch in "system service" and pole changes in "system renewal").

2.0-VECC -8

Reference: Exhibit 2, Table 4, page 16

a) In 2017 Hearst spend 42% more than budgeted on system renewal projects and 90% less on general plant projects than anticipated in its last distribution system plan. Please explain the reasons for this variance.

Hearst Power:

a) 42% increase in system renewal ($40k variance):
In 2017, Hearst Power was looking to complete some 2016 poles changes that was deferred as well as those planned for 2017 but ended up with even more poles to be replaced due to unexpected pole replacements (ie: accidents, wood pecker damage, etc). Additionally, $19k of the $40k variance was spent on reactive repairs to transformers that broke down.

b) 90% less on general plant ($35k variance):
A pickup truck replacement was budgeted for $35k in 2017 but due to manufacturing delays, the pickup was received and capitalized in 2018.

2.0-VECC -9

Reference: Exhibit 2, Table 4, page 18 & 42

a) In 2018 Hearst spent $13,879 on Electric Vehicle Charging Stations. Please explain why this is an appropriate distribution system investment.
b) Given the inability of Hearst to acquire electric vehicles who currently uses the installed two stations?
c) How many EV or hybrid vehicles are estimated to be in the Town of Hearst?

Hearst Power:

a) In 2018, Hearst Power saw an opportunity for converting it next Leadhand vehicle purchase to an EV as grants were made available at that time. The

$13,879 spent was offset by $10,695.93 received in Provincial grants. It is appropriate since Hearst Power wants to lead by example and EVs are the future of the transportation industry.

b) Hearst Power is very much frustrated by the fact that the current local dealers do not want to train their mechanics to work on EV vehicles, therefore, none of our local dealers are able to sell and provide warranty service on these EV vehicles. The closest dealer of EVs is located 90 km away, and not located within the Hearst Power geographical limits. The management at Hearst Power is very much hopeful that this situation will change and that in the years to come, EVs will be able to be purchased in Hearst. Currently, cards for using these EV stations are handed to the owners of EV vehicles who request access and billing of electricity cost is computed using the ChargeLab program. To put this in perspective, 831 kWh was withdrawn from these stations in 2020.

c) Currently, around 15-20 residents own electric vehicles.

2.0-VECC -10

Reference: Exhibit 2, Table 4, page 21

a) Please confirm (or correct) that Hearst acquired a new pickup truck in 2019 for $3,454.

Hearst Power:

a) In 2019, Hearst Power acquired a double axle trailer for the amount of $3,454. Therefore, the amount is correct but the description is not. Exhibit 2, page 21 was updated to show “Transportation – New trailer : $3,454”, instead of “Transportation – New pickup: $3,454”.

2.0-VECC -11

Reference: Exhibit 2, Table 4, page 38, (DSP, pages 6,31,82- /138)

a) Please provide how many poles were replaced in each year 2015 to 2020.
b) What was the average costs of a fully dressed pole replacement over this period?

Hearst Power:
Please refer to previous response to OEB question in 2-Staff-2

2.0-VECC -12

Reference: Exhibit 2, Table 4, page 39

a) What is the basis/reason for replacing the "run-to-failure" practice for line transformers with a proactive program of 5-10 transformers per year?
b) In each of the past 5 years how many line transformers have been reactively replaced and how many proactively replaced?
c) What are the SAIDI and SAIFI or other reliability benefits are expected with this change in policy? What is the improvement in outages due to equipment failure that Hearst expects from this change in policy?
d) What is the annual incremental cost of this new policy?

Hearst Power:
a) Please refer to response to similar OEB question 2-Staff-3

b) All replacement in last 5 years have been reactively replaced:
2016 → 2 stand-alone transformers
2017 → 1 stand-alone transformer and 1 transformer bank
2018 → 3 stand-alone transformers
2019 → 1 stand-alone transformer and 1 transformer bank
2020 → 5 stand-alone transformers and 1 transformer bank

c) The SAIDI and SAIFI are expected to be maintained. The improvement in outages is hard to quantify as it is not possible to predict transformer failures. Very old transformers are anticipated to break at some point causing a power interruption which will likely result in a few customer power outages. It should be noted that the frequency of outages can be aggravated significantly by extreme weather conditions which may cause multiple old transformer failures and outages.

d) The annual incremental cost is $20k + yearly inflation starting in 2022.

2.0-VECC -13

Reference: Exhibit 2, Table 4, page 39

a) Please provide an update on the new bucket truck confirming the final cost is and when delivery is expected.
b) What is the estimated residual value of the 25-year-old bucket truck being replaced and how is it being disposed of?
c) What changes were made to reduce the 2021 capital budget in light of the large expense for the bucket truck in this year?

Hearst Power:

a) The bucket truck is currently being assembled in Concord, ON and is expected to be ready for end of March, early April. The final pricing include:
    i. 2021 Freightliner M2 106 truck: $96,300 confirmed
    ii. 2021 Versalift boom and body installation: $164,895, less $9,995 trade-in = $152,000 confirmed
    iii. Delivery: estimated at $3,000

b) The old bucket truck is included as an exchange in the purchase deal for a new truck. The current value is appraised at $6,000 as originally offered by the Dealership but since Hearst Power was able to find a customer to purchase the old bucket truck for $9,995, the Dealer gave 100% of this credit towards the purchase price.

c) All general plants capital investments were deferred past 2021. Pole replacement budget was reduced 10% for the year and proactive transformer replacement was deferred to 2022. It is important to note that Hearst Power has included the Bucket truck replacement in 2021 and thus using the "half year rule" regarding amortization expense, therefore showing a lesser amortization expense then actuals for the years after.

2.0-VECC -14

Reference: Exhibit 2, DSP, page 74 (7,34/138)

a) Please explain what "long term load transfer decision" has been made and how it impacts Hearst's distribution system plan.

Hearst Power:

a) As per OEB decision and order EB-2016-0336, between Hearst Power Distribution and Hydro One (Joint application for Elimination of Load Transfer Arrangements) Hearst Power transferred 11 customers to Hydro One including the distribution assets for their connections ($17k sold by Hearst Power). Hydro One transferred 8 customers to Hearst Power including the distribution assets for their connections ($24k purchased by Hearst Power).

The impact is insignificant in value, electricity sales, customer count and distribution assets.

2.0-VECC -15

Reference: Exhibit 2, page 78 (DSP 11/138)

(Reference Appendix 5-A filing requirements)			
Metrics			
Metric Category	Metric	Measures	
		1 Year	5 Year Average
Cost	Total Cost per Customer1	232.25	238.16
	Total Cost per km of Line2	6594.65	6777.78
	Total Cost per MW3	48209.99	49997.08
CAPEX	Total CAPEX per Customer	60.14	64.28
	Total CAPEX per km of Line	1707.82	1829.22
O&M	Total O&M per Customer	172.10	173.88
	Total O&M per km of Line	4886.83	4948.56
Notes to the Table:			
1 The Total Cost per Customer is the sum of a distributor's capital and O&M costs divided by the total number of customers that the distributor serves.			
2 The Total Cost per km of Line is the sum of a distributor's capital and O&M costs divided by the total number of kilometers of line that the distributor operates to serve its customers.			

3 The Total Cost per MW is the sum of the distributor's capital and O&M costs divided by the total peak MW that the distributor serves.

a) Please identify the years shown in the "Measures" column

Hearst Power:

a) See below revised Appendix 5-4 Metrics. In reviewing the data, we discovered an error and have corrected this. Our sources of information are:
   - Yearbook of Electrical Distributors for total customers, Total km of line, peak MW for the year.
   - Table 17 Historical Capital Expenditure Summary 2016-2020; page 38 of 138 of the current DSP for the values 2016 to 2019 of the Capital and O&M expenditures and the corresponding table of the previous DSP for the 2015 Capital and OEM expenditures.

b) The years in the "Measure" column are 1 Year is 2019 the last year of Yearbook data available and the 5 year average is 2015 to 2019.

Appendix 5-A
Metrics

Metric Category	Metric	Measures	
		1 Year (2019)	5 Year Average (2015-2019)
Cost	Total Cost per Customer[1]	237.41	241.84
	Total Cost per km of Line[2]	6,594.65	8,001.20
	Total Cost per MW[3]	40,628.76	40,435.35
CAPEX	Total CAPEX per Customer	61.48	63.71
	Total CAPEX per km of Line	1,707.82	2,055.46
O&M	Total O&M per Customer	175.93	178.13
	Total O&M per km of Line	4,886.83	5,945.74

Notes to the Table:

1 The Total Cost per Customer is the sum of a distributor's capital and O&M costs divided by the total number of customers that the distributor serves. Captial is the Net capital from Table 17 Pg 38 of 138 in the DSP. Customer count is from the OEB statistical Yearbook for the corresponding year.

2 The Total Cost per km of Line is the sum of a distributor's capital and O&M costs divided by the total number of kilometers of line that the distributor operates to serve its customers. Capital is the net capital from Table 17, page 38 of 138 in the DSP. km of line is from the OEB statistical Yearbook for the corresponding year.

3 The Total Cost per MW is the sum of the distributor's capital and O&M costs divided by the total peak MW that the distributor serves. The peak MW is the highest number of MW supplied in the year in question.

2.0-VECC -16

Reference: Exhibit 2, page 84 (DSP 17/138)

a) Please explain what steps Hearst Power takes to notify customers of planned outages like that in 2017 which impacted 1,099 customers for almost 6 hours.
b) For maintenance programs like the porcelain insulator replacement (described at pages 23- of the DSP) what advance notice is provided customers of scheduled outages?

Hearst Power:

a) The notification process for planned outages impacting > 50 customers starts 3 weeks prior to the outage:
    1. Publish for 2 weeks in local newspaper
    2. Advertise on the local radio
    3. Publish on our website
    4. Publish a notification on Facebook and "promote" ($)
    5. Email list of customers which have provided consent to be contacted for power outage notifications
    6. Call larger customer and hospital, if impacted.

    Note that planned longer outages are usually schedule for Sunday morning, starting around 5 to 6 am and ending before noon.

b) The notification process for planned outages impacting < 50 customers starts 1-3 weeks prior to the interruption:
    1. Deliver door to door notice (in-hand or posted on front door)
    2. Publish on our website
    3. Publish a notification on Facebook and "promote" ($)
    4. Email list of customers which have provided consent to be contacted for power outage notifications
    5. Call larger customer and hospital, if impacted.

    Note that small power interruption are usually planned taking into consideration the customers that will be losing power, for example, school impacting interruptions would be done after 4pm or on weekends, residentials interruptions would be done during the day in a work week and business interruption during weekends.

2.0-VECC -17

Reference: Exhibit 2, page 80 (DSP 13/138)

a) Table 2 (Customer – Hours by Cause) and Table 4 (Customer Interruptions by Cause) show a significant increase in interruptions due of defective equipment in 2018 and 2019. Please explain the reasons for these increases.

Hearst Power:

a) In 2018 the increase was driven by 3 incidents:
   - One broken switch located near the start of a feeder which caused a 60 minutes outage for 1132 customers (1,151 customer hours)
   - Another broken switch located which caused a 69 minutes outage for 1,080 customers (1,242 customer hours)
   - One broken insulator which caused a 118 minutes outage for 421 customers (828 customer hours)

   These 2 incidents account for 3,221 hours out of the 3,636 in Table 2.

   In 2019 the increase was driven by 2 incidents:
   - One blown lightning arrestor located at the start of a feeder which caused a 45 minutes outage for 1505 customers (1,129 customer hours)
   - One broken switch which caused a 37 minutes outage for 427 customers (270 customer hours)

   These 2 incidents account for 1,400 hours out of the 1,529 in Table 2.

Since 2018 Interruption data is based on actual meter cut-off time and not as per the time of notification as it was reported pre-2018. Some results may seem unusually high, but it is the result of single incidents/defects that are bound to happen on a 97 km distribution circuit and based on the location of these defects, an interruption may affect anywhere from 1 single customer to 2770 customers.

2.0-VECC -18

Reference: Exhibit 2, pages 80- (DSP 13-/138)Table 4, page 39

a) Please update Table 1 through 8 for the 2020 reliability results.
b) Given the change in methodology for collecting data starting in 2018 how reasonable is to compare the pre- and post-2018 reliability data?

Hearst Power:

a) Here are Table 2 to 8 updated with the 2020 reliability results (Table 1 is not related to reliability results):

Table 2: Customer - Hours by Cause

		Year					
Category	**Category Description**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
0	Unknown	17	149	2196	38	0	0
1	Scheduled	3485	2133	8185	2898	5036	1842
2	Loss of Supply	119098	2999	25047	5264	23508	29012
3	Trees	18	11	17	0	0	21
4	Lightning	0	25	23	142	0	9
5	Defective Equipment	283	664	225	3636	1529	6303
6	Adverse Weather	0	121	7	0	0	44
7	Adverse Environment	0	37	0	144	0	217
8	Human Element	0	0	1117	219	0	0
9	Foreign Interference	1729	2931	180	326	293	488
	Totals- All interruptions	124629	9070	36997	12667	30367	37936
	Total excluding "loss of supply"	5531	6071	11950	7403	6858	8925
	Total excluding "loss of supply" and "Scheduled"	2046	3938	3765	4505	1822	7082

Table 3: System Interruptions by Cause

		Year					
Category	**Category Description**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
0	Unknown	2	7	3	2	0	0
1	Scheduled	29	28	19	38	18	27
2	Loss of Supply	10	3	4	3	5	1
3	Trees	1	2	1	0	0	1
4	Lightning	0	2	2	2	0	1
5	Defective Equipment	12	12	9	15	9	9
6	Adverse Weather	0	2	2	0	0	1
7	Adverse Environment	0	2	0	1	0	2
8	Human Element	0	0	2	2	0	0
9	Foreign Interference	16	26	12	11	11	17
	Totals- All interruptions	70	84	54	74	43	59
	Totals –excluding " loss of supply"	60	81	50	71	38	58
	Totals –excluding "loss of supply" and "Scheduled"	31	53	31	33	20	31

Table 4: Customer Interruptions by Cause

		Year					
Category	**Category Description**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
0	Unknown	15	367	1819	4	0	0
1	Scheduled	924	1150	2114	2123	1213	607
2	Loss of Supply	17098	1271	8550	5930	8656	2763
3	Trees	3	11	1	0	0	25
4	Lightning	0	15	6	210	0	10
5	Defective Equipment	219	707	172	2921	1970	2142
6	Adverse Weather	0	17	4	0	0	30
7	Adverse Environment	0	25	0	90	0	87
8	Human Element	0	0	664	354	0	0
9	Foreign Interference	809	1227	107	96	65	504
	Totals- All interruptions	19068	4790	13437	11728	11904	6168
	Totals -not loss of supply	1970	3519	4887	5798	3248	3405
	Totals -not (loss of supply and Scheduled)	1046	2369	2773	3675	2035	2798

Table 5: Customers by Year

	Customers By Year					
Year	2015	2016	2017	2018	2019	2020
Customers	2771	2768	2763	2768	2760	2763

Table 6: CAIDI by Year

Cause & Description	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
0-Unknown	1.12	0.4	1.21	9.62		
1-Scheduled	3.77	1.86	3.87	1.37	4.15	3.04
2-Loss of Supply	6.97	2.36	2.93	0.89	2.72	10.50
3-Trees	6.1	1	17.38			0.61
4-Lightning		1.69	3.91	0.67		0.90
5-Defective Equipment	1.29	0.94	1.31	1.24	0.78	2.94
6-Adverse Weather		7.1	1.84			1.48
7-Adverse Environment		1.5		1.6		2.49
8-Human Element			1.68	0.62		
9-Foreign Interference	2.14	2.39	1.68	3.39	4.51	0.97
Annual –All Interruptions	6.54	1.89	2.75	1.08	2.55	6.15
Annual -excluding "loss of supply"	2.81	1.73	2.45	1.28	2.11	2.62
Annual -excluding "loss of supply" and "Scheduled"	1.96	1.66	1.36	1.23	0.9	2.53

Table 7: SAIDI by Year

Cause & Description	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
0-Unknown	0.01	0.05	0.79	0.01	0	0
1-Scheduled	1.26	0.77	2.96	1.05	1.82	0.67
2-Loss of Supply	42.98	1.08	9.07	1.9	8.52	10.50
3-Trees	0.01	0	0.01	0	0	0.01
4-Lightning	0	0.01	0.01	0.05	0	0.00
5-Defective Equipment	0.1	0.24	0.08	1.31	0.55	2.28
6-Adverse Weather	0	0.04	0	0	0	0.02
7-Adverse Environment	0	0.01	0	0.05	0	0.08
8-Human Element	0	0	0.4	0.08	0	0
9-Foreign Interference	0.62	1.06	0.07	0.12	0.11	0.18
Annual -All	44.98	3.28	13.39	4.58	11	13.73
Annual-excluding "loss of supply"	2	2.19	4.33	2.67	2.48	3.23
Annual-excluding "loss of supply" and "Scheduled"	0.74	1.42	1.36	1.63	0.66	2.56

Table 8: SAIFI by Year

Cause & Description	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
0-Unknown	0.01	0.13	0.66	0	0	0
1-Scheduled	0.33	0.42	0.77	0.77	0.44	0.22
2-Loss of Supply	6.17	0.46	3.09	2.14	3.14	1.00
3-Trees	0	0	0	0	0	0.01
4-Lightning	0	0.01	0	0.08	0	0.00
5-Defective Equipment	0.08	0.26	0.06	1.06	0.71	0.78
6-Adverse Weather	0	0.01	0	0	0	0.01
7-Adverse Environment	0	0.01	0	0.03	0	0.03
8-Human Element	0	0	0.24	0.13	0	0
9-Foreign Interference	0.29	0.44	0.04	0.03	0.02	0.18
Annual -All	6.88	1.73	4.86	4.24	4.31	2.23
Annual - Excluding "loss of supply"	0.71	1.27	1.77	2.09	1.18	1.23
Annual - Excluding "loss of supply" and "Scheduled"	0.38	0.86	1	1.33	0.74	1.01

b) The main difference between the years is the precision of the data, where pre-2018 was reported based on 5 minutes interval and post-2018 is reported by the minute. For example: in 2016, if a customer called and reported an outage a 6:00pm, it was tabled to have started at 6:00pm. In 2018, this same outage would have had a meter verification and the exact time of the outage would have been determined, which may have been 5:57pm. Pre-2018, meter outage time verification was only done when the power outage time was unsure or unreported but post-2018, it is done all the time to increase data precision.

2.0-VECC -19

Reference: Exhibit 2, Appendix 2-AA

a) Please explain the usually large amount for meter in 2018 ($24,429). Was the $5,000 for meters in 2020 spent?

Hearst Power:

a) Hearst Power maintains around 2760 meters in service, including all types of meters. The smart meter deployment started in 2008 and was completed in 2011 but most meters were installed in the first year (2008). Meters require re-sealing after their date of expiration which is usually 10 years for the first re-seal. Therefore in 2018, 200 meters were to be sent to Measurement Canada for inspection. Hearst Power had originally planned to send many small batches of meters in order to avoid purchasing many new meters. But with longer then expected delays and meters issues, Hearst Power proceeded with the purchase of 200 additional meters in order to complete the process prior to meter expiration dates.

In 2020 a Purchase Order for 26 industrial and bi-lateral meters ($5k) was issued, but due to COVID-19 and its impact on Measurement Canada, no meters have been received as of March 2021. Therefore, to answer the question clearly, no dollars were actually spent in 2020 on meter related capital projects.

Note: As per new OEB regulations regarding the requirement for MIST meters for certain type of customers, Hearst Power had also ordered 44 MIST meters in May 2020 ($20k) but still have not yet received these meters. The accounting of this MIST meters will be flowing through variances account for disposal at a later date based on the guidelines.

2.0-VECC -20

Reference: Exhibit 2, Appendix 2-AA

a) Please update Appendix 2-AA to include 2020 actual results.

Hearst Power:

a)

	System Access	***2020***	***2021***
Projects	Projects		
		Projection	**Projection**
System Access	**System Access**		
	New construction/service	$0	$15,000
	Sub-Total System Access	**$0**	**$15,000**
Contributed Capital	Paid back by customer	0	-15,000
	Sub-Total System Access - Contributed Capital	**0**	**-15,000**
Total System Access		**0**	**0**
			MIFRS
	System Renewal	**2020**	**2021**
	1830 - Distribution Overhead - Replace Poles	$137,725	$100,000
	1840 - Underground Conduits		
	1845 - U/G conductors and devices		$0
	1850 - Line Transformers - Replace transformer	$21,846	$15,000
	Sub-Total System Access	**$159,571**	**$115,000**
Contributed Capital			
	Sub-Total System Renewal - Contributed Capital	**0**	**0**
Sub-Total System Renewal		**159,571**	**115,000**
	System Service	**2020**	**2021**
	1855 - Services	$1,353	$2,500
	1860 - Meters - New meters		$0
	1835 - Overhead Conductors & Devices - OH devices, Replace porcelain surge arrestors, new solid blade switch	$1,379	$5,000
	Sub-Total System Service	**$2,732**	**$7,500**
Contributed Capital			
	Sub-Total System Service - Contributed Capital	**0**	**0**
Sub-Total System Service		**2,732**	**7,500**

	General Plant	**2020**	**2021**
	1611 - Computer Software		$0
	1908 - Building & Fixtures - New natural gas furnace + Bulding sign		
	1908 - Building & Fixtures - Warehouse interior renovations (Interior flooring, walls & doors)		
	1908 - Building & Fixtures - Electric Vehicle Charging Stations		
	1908 - Building & Fixtures	$18,163	
	1915 - Office Furniture Equipment	$2,402	
	1920 - Computer Equipment Hardware		
	1920 - Computer Hardware		
	1930 - Transportation - New Burcket truck		$265,000
	1930 - Transportation - New Pickup		
	1940 - Tools & Equipment - New tools	$5,234	
	1940 - Tools & Equipment - Trencher		
	1940 - Tools & Equipment - Wood chipper		
	Sub-Total System Access	**$25,799**	**$265,000**
Contributed Capital			
	Sub-Total General Plant - Contributed Capital	**0**	**0**
Sub-Total General Plant		**25,799**	**265,000**
		MIFRS	**MIFRS**
		2020	**2021**
	Hpdc Capital Investment Net Of Cc	$188,102	$402,500
	Total Contributed Capital	$0	-$15,000
	Total Capex	$188,102	$387,500
	Reconciliation To Yearly Additions (2.6)	**188,103**	**387,500**

2.0-VECC -21

Reference: Exhibit 2, pages 108 (DSP 41/138)

"*HPDC operates and maintains 2 Bucket Trucks, 1 Derrick Digger, and 2 pickup trucks in their fleet*."

a) How many crews does Hearst operate with?
b) If Hearst operates with only one crew why does it need two bucket trucks?
c) If Hearst is not planning any underground replacement why does it continue

to need a digger?

d) Was (and is) this digger used for the underground fibre-to-the-home deployment in the Town of Hearst?

Hearst Power:

a) Hearst Power employees 4 Powerline Technicians, therefore, when all 4 are working, 2 crews are available.

b) All three pieces of equipment (2 bucket, 1 derrick digger) are used during most pole replacement (please refer to photos below).
A derrick digger is used to:

- Dig the pole hole
- hold live wire
- to place the pole in place, etc.

Two bucket trucks are required:

- In order to have the possibility to have 2 crews to be dispatch during multiple power interruptions
- Complete quicker pole change so that customer have shorter interruption periods (twice as fast overhead work with 2 Powerlineman in the air)
- Since a bucket truck is a critical asset for our company, it is important to have two trucks in operation so that when one is in need of repair or inspection Hearst Power can continue with the maintenance of the distribution system, particularly given that no bucket trucks are available for rent in the area.


ÉCOLE CATHOLIQUE
PAVILLON NOTRE-DAME


SUBWAY
BREAKFAST SERVED
ALL DAY

c) A derrick digger is not meant for underground work, it is mainly meant for digging, setting, rigging and removing utility poles. See below illustration of a typical derrick digger.

d) No, similar response to question c). The digger was not used for underground fibre-to-the-home deployment in the Town of Hearst.

2.0-VECC -22

Reference: Exhibit 2, pages 142 (DSP 75/138)

a) Please update Table 5 (Plant Capital for 2020) for 2020 year-end results.
b) Please update Table 6 (Plant Capital for 2021) if necessary due to changes in 2020 results.

Hearst Power:

a)

HPDC	**Table 5: Plant Capital for 2020**			
	Amounts are in dollars			
Category	**Description**	**Plan**	**Unaudited Year end**	**Variance**
System Access				
	New construction/service (Note 1)	$15,000	0	-$15,000
System Renewal				
	1830 - Distribution Overhead – Poles (Note 2)	$110,000	$137,725	
	1845 - U/G conductors and devices	n/a	$0	
	1850 - Line Transformers (Note 3)	$25,000	$21,846	
	Subtotal	$135,000	$159,572	$24,572
System Service				
	1835 - Overhead Conductors & Devices - New solid blade switch (S	$5,000	$1,379	
	1855 – Services (See Note 5)	$2,500	$1,353	
	1860 - Meters - New meters	$5,000	$0	
	Subtotal	$12,500	$2,731	-$9,769
General Plant				
	1908 – Building Fixtures- New overhead door, warehouse (See Note	$25,000	$18,163	
	1915 – Office Furniture Equipment -New phone System (See Note 8	$2,500	$2,402	
	1940 - Tools & Equipment (See Note 9)	$5,000	$5,234	
	Subtotal	$32,500	$25,799	-$6,701
	Total Capital	$195,000	$188,103	-$6,897
	Contributed Capital	-$15,000	$0	$15,000
	Net Capital	$180,000	$188,103	$8,103

b) There is no material change to be made from the planned Plant Capital 2021. Only a transfer of $10k from the bucket truck purchase to meter purchase.

HPDC	Table 5: Plant Capital for 2021	
Category	**Description**	**Plan**
System Access		
	New construction/service	$15,000
System Renewal		
	1830 - Distribution Overhead – Poles	$100,000
	1850 - Line Transformers	$15,000
	Subtotal	$115,000
System Service		
	1855 – Services	$2,500
	1835 - Overhead Conductors & Devices - New solid blade switch	$5,000
	1860 - Meters - New meters	$10,000
	Subtotal	$17,500
General Plant		
	1930 - Transportation – New bucket truck	$255,000
	Subtotal	$255,000
	Total Capital	$402,500
	Contributed Capital	-$15,000
	Net Capital	$387,500

2.0-VECC -23

Reference: Exhibit 2, pages 209

a) Please update Appendix 2-G (SAID & SAIFI Results) to include 2020 results.

Hearst Power:

a)

Index	Including outages caused by loss of supply						Excluding outages caused by loss of supply						Excluding Major Event Days					
	2015	2016	2017	2018	2019	2020	2015	2016	2017	2018	2019	2020	2015	2016	2017	2018	2019	2020
SAIDI	44.98	3.28	13.39	4.58	11	13.73	2	2.19	4.33	2.67	2.48	3.23	2	2.19	4.33	2.67	2.48	3.23
SAIFI	6.88	1.73	4.86	4.24	4.31	2.23	0.71	1.27	1.77	2.09	1.18	1.23	0.71	1.27	1.77	2.09	1.18	1.23
	5 Year Historical Average (2016-2020)																	
SAIDI						9.196						2.980						2.980
SAIFI						3.474						1.508						1.508

Exhibit 3 – Revenues

PREAMBLE:

Please find below information pertaining to HPDC's 2019 load in comparison to 2020 load. HPDC confirms that the
the load forecast as filed. The forecast was based on 2010-2019 actuals with 2020 and 2021 predicted. The second table shows the load forecast 2020 updated for actuals. The scenario in question forecasts 2021 based on 2011-2020 actuals. HPDC notes that the 2020 was impacted.

Comparison of 2019 Actuals to 2020 Actuals

Wholesale	2019	2020 Actuals	Var kWh 2020-2019	Var % 2020-2019
January	8,506,377	7,650,299	(856,078)	-10.06%
February	7,640,418	7,344,218	(296,200)	-3.88%
March	7,624,926	7,055,004	(569,922)	-7.47%
April	6,661,885	5,251,462	(1,410,423)	-21.17%
May	6,203,517	5,473,388	(730,129)	-11.77%
June	5,641,360	5,524,304	(117,056)	-2.07%
July	5,856,572	5,206,282	(650,290)	-11.10%
August	5,474,622	5,569,136	94,514	1.73%
September	5,837,391	5,617,720	(219,671)	-3.76%
October	6,503,153	6,604,709	101,556	1.56%
November	7,207,521	7,053,319	(154,202)	-2.14%
December	7,670,981	7,658,409	(12,572)	-0.16%
Total	80,828,723	76,008,250	(4,820,473)	-5.96%
RRR 2.1.5				

3-Staff-1

COVID-19
Ref: Exhibit 3, Page 23
Hearst Power's load forecast does not make reference to the COVID-19 pandemic. The variables chosen, HDD, CDD, spring and fall flag, Shutdown, and days in month are not forecasted reflecting impacts of the COVID-19 pandemic.

a) Please confirm OEB staff's interpretation that the proposed load forecast does not reflect any impacts of the COVID-19 pandemic or explain how these are captured.
b) Please explain Hearst Power's plans for addressing any impacts of the COVID-19 pandemic on customer load in 2021, and the following IRM period.
c) For all months available in 2020, please provide the monthly energy use for each rate class, and the monthly demand for each demand billed rate class.

Hearst Power:

a) HPDC confirms.

b) As indicated in the preamble, the load saw a reduction specifically in the General Service and Intermediate Classes. HPDC proposes to use the load forecast as filed which is more reflective of a normal year and yields lower rates.

c) Please see the preamble section at the previous page.

3-Staff-2

Wholesale Purchases
Ref: Exhibit 3, Page 8
Ref: Load Forecast Model, sheet Bridge&Test Year Class Forecast

The load forecast table presented on page 8 indicates that the intermediate class used 19,768,633 kWh in 2015, 2016, and 2017. The worksheet Bridge&Test Year Class Forecast indicates this amount for 2017, but indicates that 2015 consumption was 20,176,329 kWh, and 2016 consumption was 20,606,236 kWh.
OEB staff has populated the following table based on the data in the Bridge&Test Year Class Forecast worksheet. OEB staff notes that according to the table below, wholesale purchases exceed total delivered energy in most years, but are less than delivered energy in 2014. In addition, the difference is between 2.1 and 3.3 GWh in most years, but has varied as high as 5.8 GWh, and fallen to approximately 1.1 GWh in consecutive years.

Energy use (MWh) by rate class vs Wholesale

Year	Residential	GS < 50	GS > 50	Intermediate	Sentinel	Street Light	Total	Wholesale	Difference
2010	24,737	11,500	17,451	18,965	22	1,009	73,683	79,483	5,800
2011	24,621	11,815	21,470	19,113	21	1,009	78,049	80,394	2,345
2012	23,814	11,024	23,664	20,375	21	1,021	79,920	81,056	1,136
2013	25,300	11,360	23,218	21,805	21	1,026	82,731	83,802	1,071
2014	25,242	11,111	23,609	23,201	21	1,030	84,215	83,570	-645
2015	23,679	10,713	25,487	20,176	17	1,031	81,103	83,275	2,172
2016	22,546	10,267	25,437	20,606	13	565	79,435	81,559	2,124
2017	21,777	10,334	24,933	19,769	9	448	77,271	80,227	2,956
2018	22,435	11,004	24,389	19,994	9	449	78,280	80,616	2,336
2019	22,187	10,694	24,265	20,144	9	449	77,748	80,829	3,081
2020	23,652	10,991	23,398	19,969	10	451	78,472	81,782	3,309
2021	23,652	10,991	23,398	19,969	10	454	78,475	81,782	3,307

a) Please confirm that the Bridge&Test Year Class Forecast is correct in 2015 and 2016, not the evidence at page 8 of Exhibit 3.

b) Please explain the causes of the differences between wholesale and total delivered energy. In particular, please address the causes of the variability between 2010 and 2015, including where wholesale was less than total delivered energy.

Hearst Power:

a) and b)

HPDC has reviewed its Load Forecast inputs and notice some discrepancies which included:

- In the year 2010-2013, the value compiled for kWh purchased on Hydro One was different then the kWh purchase for the period of 2015 to 2020, because the previous general managers recorded this data differently.
- The Wholesale did not include MicroFit generators, only included the power purchased based on invoices from the IESO and Hydro One, and starting in 2014, the power purchased from one large FIT generator
- The Energy used by rate class (power sold) included in the previous load forecast was compiled manually in those years but using new billing software functions in recent years, the electricity sales data in 2010 and 2011 was extracted and showed a slight difference.

HPDC has revised the load forecast to resolve the issue stated above.

As for the cause for the smaller "loss" in 2015 (Wholesale – Energy Use = Loss), it is due to a new FIT generator being connected to Hydro One's pole line within HPDC's geographical area in the summer 2014. For approximately 1 month earlier than his specified OPA contract start date, the FIT generator was connected by Hydro One to the grid but not metered by Hearst Power and not paid. The metering for this generator was approved by Hydro One and is managed by an external party. As of the date of the OPA contract, Hearst Power started receiving metering data and accounting for the kWh generated. The kWh generated (prior to the approved OPA contract start date) by this FIT generator were used by Hydro One to offset their power sales invoice to HPDC for that period.

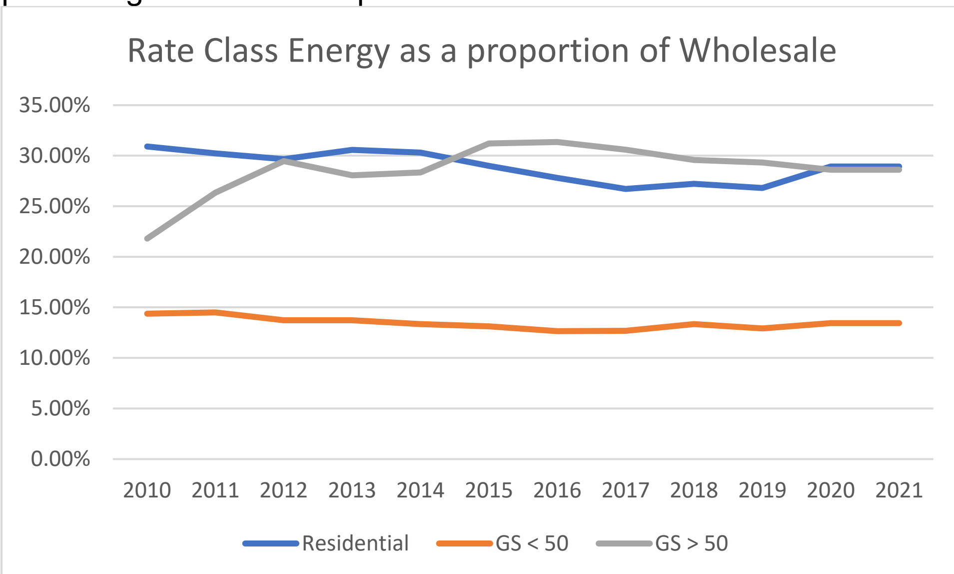
3-Staff-3

Load Forecast
Ref: Exhibit 3, Page 34
Ref: Load Forecast Model, sheet Bridge&Test Year Class Forecast

In explaining the methodology for forecasting energy use of weather sensitive rate classes, Hearst Power states that "forecast values for 2021 are allocated based on the most recent year's 2019 actual share." However, the worksheet Bridge&Test Year Class

Forecast appears to calculate this in cells D15, D16, D43, D44, D71 and D72 as a ten-year average of 2010-2019.

OEB staff has prepared the following graph of energy purchases by rate class as a percentage of wholesale purchases.



a) Please confirm OEB staff's understanding that the 2021 forecast is calculated using a ten-year average of shares from 2010-2019.
b) Please confirm that General Service > 50 kW class exhibits an increasing trend over the period 2010 – 2019 while Residential and General Service < 50 kW classes exhibit decreasing trends over the same time period.
c) Please explain how a ten-year average is indicative of the 2021 share of wholesale when the percentage shares are exhibiting different trends over the time period.

Hearst Power:

a) Confirmed

b) Following the 2008 economic crisis, Hearst Power's GS>50 class which includes the large manufacturing mills in Hearst felt the impacts into 2010. One Intermediate customer had to shut down at that time. The economy and GS>50 consumption returned relatively to normal after 2012 and significant CDM activities in 2015 has impacted the decrease every year after

c) The "bridge&Test Year Class Forecast" tab calculates the predicted based on the ratio of the specific class in comparison to the wholesale. As scan be seen from the forecast methodology, the per class forecast is reflective of the individual class' trend. HPDC maintains that the methodology and per class prediction is appropriate.

3-Staff-4

Wholesale Purchases
Ref: Exhibit 3, Page 21
Ref: Load forecast Model; Sheet Input – Adjustments & Variables
For March 2010, the unadjusted wholesale is reported as 6,126,461 kWh. Instead, Hearst Power used a calculated average of March from the years 2011, 2012, 2013, 2014, 2015, 2017, 2018, 2019, which has calculated as 7,734,565 kWh.

For June 2012, the unadjusted wholesale is reported as 5,011,748 kWh. Instead, Hearst Power used a calculated average of June from the years 2013, 2014, 2015, 2016, 2017, 2019, which has calculated as 7,734,565 kWh. The formula references two blank cells which were not factored into the average.

a) Why did Hearst Power use calculated averages instead of the observed wholesale energy for the two months noted above?
b) Did Hearst Power consider year-to-year variability when using averages?
c) Why was March 2016 excluded from the average for March 2010?
d) Why were June 2010, 2011, and 2018 excluded from the average for June 2012?

Hearst Power:

a) Two specific readings were flagged as outliers in the scatter plot. Not being able to pinpoint the reasons for it, the utility felt it would be prudent to use an average instead.

b) HPDC did not consider a year-to-year variability.

c) Excluding the above quoted months were an omission. HPDC notes that the impact is on the average used, RateBase, Revenue Requirement is marginal

June 2012: as filed 5,875,376 using 10-year average: 5,180,185
Mar 2010: as filed 7,734,565 using 10-year average 7,777,464

3-Staff-5

Regression Model
Ref: Load forecast Model; Sheet Forecast
Hearst Power appears to have indicated that the following months have 29 days:

February 2013, February 2017, February 2019, February 2020, February 2021, and that February in the remaining years has 28 days.

a) Please revise the model to reflect the correct number of days in February each year.

Hearst Power:

a) The model has been revised to reflect the changes indicated in 1-Staff-1.

3-Staff-6

Regression Model
Ref: Exhibit 3, Pages 23-25
Ref: Load Forecast Model; sheet Forecast, sheet Output

Hearst Power states that "the Days per Month only slightly improved the R-Square. However, the utility still opted to keep them as part of the regression analysis."

The regression output indicates a t-stat of 1.910 for the "Days in month" variable. The CDD, Shutdown, and Spring/Fall variables have t-stats of 0.106, 0.184 and – 1.687 respectively, all of which are less significant than Days per Month.

The Shutdown variable has a value 0 in July and August, and a value of 1 in all other calendar months. It has a positive coefficient of 23,789. When describing the variables, Hearst Power states: "'Shutdown' which was used in the last OEB approved forecast and lastly (5) the number of days in the month and reflects the seasonal shutdown of the main intermediate customer."

Hearst Power appears to describe the Spring/Fall variable as accounting "for the seasonal increase in consumption in the summer and winter months." The variable name suggests that it would indicate the spring months and the fall months. However, the variable has a value of 1 in the months of April to October, and a value of zero in the months November to March.

a) Did Hearst Power consider eliminating the CDD and Shutdown variables?
b) Please provide a scenario including the regression outputs and resulting load forecast where the CDD and Shutdown variables are eliminated.
c) Please clarify what is meant by a 1.0 for the Shutdown variable. If this indicates that a customer is shut down for the season, please explain how the shutting of a customer results in increased energy use.
d) Please explain how the months used in the Spring/Fall variable were selected, and the purpose for selecting these months?

Hearst Power:

a) HPDC did not consider eliminating the CDD variable but did explore the regression without the Shutdown flag.

b) The hypothetical scenario has been filed along with these responses.

c) The shutdown flag denotes when the factory shuts down for several months in the summer. HPDC notes that this variable was also used in its 2015 load forecast, yielded favorable results and was approved as part of the utility's previous load forecast.

d) December to February as well as June July and August are flagged as extreme months while March, April, May, September, October and November are flagged as Spring and Fall flags.

3-Staff-7

Ref: Exhibit 3 – Revenues, Tables 34 & 35

Hearst Power reported revenues of $402,308 and expenses of $294,921 associated with the management of Conservation Demand Management and Affordability Fund programs over the 2017 to 2018 period and revenues of $697,798 and expenses of $612,441 associated with the management of the same programs over the 2018 to 2019 period.

Per the Energy Conservation Agreements between individual utilities and the IESO (then the OPA) utilities were permitted to retain a Cost Efficiency Incentive related to utility performance in offering conservation programs.

(a) Please confirm whether these reported profits associated with the management of Conservation Demand Management and Affordability Fund programs are the Cost Efficiency Incentives permitted by Hearst Power's Energy Conservation Agreement with the IESO. If so, please provide any additional, relevant supporting documentation.

(b) Should these reported profits not be related to a Cost Efficiency Incentive, please explain the driver behind the revenues and expenses noted. In the response, please provide the contractual details that permitted Hearst Power to record such profits from the management of Conservation Demand Management and Affordability Fund programs.

Hearst Power:

a) and b)

For the year 2018 the bulk of the net revenue is attributable directly to the Cost Efficiency Incentive paid to Hearst Power in relation to the Conservation and

Demand Management Program ("CDM Program"); please see attached LDC Report for Hearst Power dated October 15, 2018, with the incentive payment identified.

For the year 2019 the bulk of the net revenue is attributable to Hearst Power's participation as a 3rd party vendor in connection with Hydro One Network Inc.'s ("HONI's") Affordability Fund Program ("AF Program") obligations; this participation is in addition to and separate from Hearst Power's obligation to administer the AF Program for its own franchise area.

In early 2019 HONI was delivering the AF Program in its franchise area using a 3rd party, non-LDC vendor within the HONI service territory surrounding Hearst Power's franchise area. As a result of complaints about the quality of the services provided by that non-LDC vendor on behalf of HONI, including complaints registered to Hearst Power directly by HONI customers in close proximity to Hearst, HONI engaged Hearst Power to at first audit a selection of the work performed by the non-LDC vendor, and then to perform occasional work under the AF Program. As a result of the audit results and Hearst Power's demonstrated ability to deliver the AF Program on behalf of HONI effectively, and particularly in view of Heart Power's ability to deliver services in French to HONI's francophone customers in proximity to the Hearst Power franchise area, HONI engaged Hearst Power in a contract to deliver the AF Program extensively within the HONI franchise area in proximity to Hearst Power. Under the contract with HONI Hearst Power was able to earn net revenue in 2019 and 2020.

In both years some level of net revenue is attributable to the manner in which Hearst Power recovers expenses for providing the programs and accounts for them for regulatory purposes. While both programs reimbursed Hearst Power for administrating the programs, Hearst Power's General Manager, a fixed salary employee, administrated both programs as incremental duties to his existing obligations in managing the distribution company. While Hearst Power provided incentive payments to the General Manager which were recorded as expenses related to the programs, the gap between the cost of the incentives and the recovery of expenses from the programs created value for Hearst Power that is reflected as net revenue.

3.0-VECC-24

Reference: Exhibit 3, page 6

EB-2014-0080, 3-VECC-11

a) Per Exhibit 3, page 6, Hearst does not have an Unmetered & Scattered Load class. In its last COS Application Hearst confirmed that all of its customers were metered except for Street Lights and Sentinel Lights. Please confirm that this is still the case.

Hearst Power:

a) HPDC confirms that this was an error in the drafting of the evidence and that the utility does not have any USL customers.

3.0-VECC-25

Reference: Exhibit 3, pages 9, 21 and 32

Load Forecast Model, Inputs – Adjustments & Variables Tab

Cost Allocation Model, Tab I6.1 (Revenue)

a) At page 32 the Application states that "MicroFit related consumption was removed from the Wholesale Purchases". Do the monthly wholesale purchases used as the dependent variable in the regression model include Hearst's purchases from FIT and microFIT facilities?

b) If not, please re-do the Load Forecast Model with the purchases from these sources included in the wholesale purchase variable.

c) Does Hearst have any customers that are wholesale market participants?

a. If not, please explain why, in the I6.1 Tab of the Cost Allocation Model, the energy values set out in rows 25 and 29 differ for the GS>50 , Intermediate, Street Light and Sentinel Classes.

b. If yes, how is their usage captured in the Load Forecast Model?

d) In the Load Forecast Model, Inputs – Adjustments & Variables Tab, the revised Wholesale Purchase values for March 2010 and June 2012 are not based on the actual values. Please explain why.

Hearst Power:

a) HPDC confirms that Microfits were not removed as an adjustment to the load prior to running the forecast.

b) Tab I6.1 of the Cost Allocation was populated in error. The model field along with these responses has been corrected to remove the inputs at line 29.

c) HPDC does not have customers that are market participants.

d) Two specific readings were flagged as outliers in the scatter plot. Not being able to pinpoint the reasons for it, the utility felt it would be prudent to use an average instead.

3.0-VECC-26

Reference: Exhibit 3, pages 23-25

a) Are the dependent variables used in the current Load Forecast Model the same as those used in Hearst's EB-2014-0080 Application?

b) If not, please explain what is different and why.

c) Does the "Shut Down" always occur in the same months of each year and does it always last to the same number of days?

Hearst Power:

a) HDD, CDD, Spring/Fall (Winter Flag) were used in the 2015 application. The customer count which was used as a dependent variable in the 2015 Load Forecast was tested but left out of the 2021 forecast as it yielded unfavorable results.

b) See above.

c) The "Shut down" is a yearly practice by local manufacturing mills to give a "break" to employee during the hot summer months (July or August) and to take this time to complete maintenance, electrical, water and natural gas repairs and upgrades. Another reason why the manufacturing mills generally do the shutdown during July is because of the peak Province-wide consumption; since they are Class A customers, they shut down during expected peak time in order to better manage their Global Adjustment fees. The shutdown period typically lasts a week but could be extended a few days if major repairs take longer to complete.

3.0-VECC-27

Reference: Exhibit 3, page 31

Load Forecast Model, Forecast Tab

a) Please confirm that, for 2021, the forecast should have used 28 as the number of days in February and not 29.

b) The values in Table 9 are materially less than the predicted monthly purchases from the Load Forecast Model. What do the values represent?

c) Please provide a Table similar to Table 9 but for 2021 (the proposed test year) the sets out the predicted monthly purchases using the 10-year average and 20-year average weather normalized values for HDD and CDD.

Hearst Power:

a) Confirmed. Please see 3-Staff-5 for details

b) & c) Please find the updated information to reflect 2010-2020

	10-year avg	**10-year avg**	**2021 Test Year using 10-year avg**
Month	HDD	CDD	
Jan	1060.3	0.0	**8378841.29**
Feb	952.6	0.0	**7886532.53**
Mar	828.1	0.0	**7761400.74**
Apr	563.7	0.0	**6792353.32**
May	283.0	5.2	**6113182.82**
Jun	110.9	19.5	**5585228.18**
Jul	39.5	57.6	**5502499.84**
Aug	73.0	26.4	**5595948.70**
Sep	186.5	7.8	**5787931.64**
Oct	418.3	0.4	**6474104.60**
Nov	649.4	0.0	**7217495.38**
Dec	932.7	0.0	**8039604.02**

	20-year	**20-year**	**2021 Test Year using 20-year avg**
	avg	avg	

Month	HDD	CDD	
Jan	1067.3	0.0	**8397537.08**
Feb	949.6	0.0	**7878567.53**
Mar	814.0	0.0	**7723969.22**
Apr	525.7	0.1	**6691203.58**
May	278.2	6.0	**6100817.42**
Jun	111.2	22.5	**5585351.80**
Jul	46.3	49.7	**5521292.16**
Aug	75.6	28.5	**5602640.28**
Sep	186.0	9.3	**5786240.80**
Oct	421.4	0.5	**6482370.50**
Nov	634.7	0.0	**7178321.91**
Dec	930.2	0.0	**8032902.24**

3.0-VECC-28

Reference: Exhibit 3, pages 32-33

a) Please confirm that the customer counts are based on an average of the 12 monthly values for the year.

b) If available, please provide the average 2020 customer count for each customer class.

a) It is noted that for 2021 the Residential customer count derived using the geomean was then increased by five. Please explain why.

Hearst Power:

a) Confirmed

b) See table below

Retail	***2020***
Residential	
Kwh	22,266,337
Cust Count	2,253
General Service < 50 kW	
Kwh	9,760,447
Cust Count	458

General Service > 50 to 4999 kW	
Kwh	23,057,696
kW	65,273
Cust Count	37
Intermediate	
Kwh	18,851,451
kW	58,716
Cust Count	2
Sentinel	
Kwh	9,452
kW	24
Cust Count	12
Street Lighting	
Kwh	450,159
kW	1,356
Cust Count	962
Total	
Kwh	**74,395,542**
kW	**128,079**
Cust Count	**2,747**
Connection Count	**976**

3.0-VECC-29

Reference: Exhibit 3, page 34

Load Forecast Model, Bridge & Test Year Class Forecast Tab

a) While the Application (page 34) states that the for the Residential, GS<50 and GS>50 classes the “forecast values for 2021 are allocated based on the most recent year’s 2019]) actual share”, please confirm that in the Load Forecast Model the historical 10 year average share was used.

b) For the Residential, GS<50 and GS>50 classes, which approach had Hearst intended to use and why?

Hearst Power:

a) HPDC confirms that the forecast is based on a 10-year average.

b) The intention as well as the model is to use a 10-year average as is (when appropriate) required in the filing requirements

3.0-VECC-30

Reference: Exhibit 3, page 41

a) Please provide the IESO/OPA reports that sets out the persisting savings through to 2021 from Hearst CDM programs implemented in 2011-2014.

Hearst Power:

a) The April 2019 Participation and Cost Report was filed along with the original application.

3.0-VECC-31

Reference: Exhibit 3, page 57

2021 Tariff Schedule and Bill Impact Model

a) Were the Retailer charges set out in Tab 5 of the 2021 Tariff Schedule and Bill Impact Model used to calculate the revenues for Accounts 4082 and 4084?

b) Were the Pole Attachment charges set out in Tab 5 of the 2021 Tariff Schedule and Bill Impact Model used to calculate the revenues for Account 4210?

c) In which account are the revenues from the microFIT service charges recorded and what are the associated revenues for 2019?

d) Were there any actual Gains (Account 4355) or Losses (Account 4360) on the Disposition of Utility and Other Property in 2020 and, if so, what are the values?

Hearst Power:

a) The increase in retailer charge was factored into the budget process.

b) Yes, the charge of $44.50 was used to calculate revenues for Account 4210, therefore resulting in an increase of $25k revenues compared to the previous year.

c) The microFIT service charges are recorded in account 4080. The revenues for these charges in 2019 was $3,110.58

d) A small Losses (account 4360) should be accounted for by our financial auditors for year end 2020. It is the removal of the remaining net value of assets that were replaced throughout the year. Hearst Power estimates the value for the year 2020 at around $500 but this amount is to be confirmed by our auditors at a later date.

Exhibit 4 – Operating Expenses

4-Staff-1

Cost Drivers
Ref: Exhibit 4, Page 19
In explaining the cost drivers for the maintenance of poles, towers and fixtures (Account 5120) for 2017-2018, Hearst Power states that:

> 2017-2018; Increase of $4,945
> Hearst Power incurred labour dispute settlement cost which were spread over multiple account including $4,945 in this account

OEB staff notes that Account 5125 also contains labour dispute settlement costs of $5,247 during 2017-2018. However, in explaining year-over-year variance analysis for 2017-2018, Hearst Power states that

> Expenses related to Operations and Maintenance are higher than 2017 by $44,793 as a result of inflation and costs related to labour disputes ($25k cost) which were allocated to several Operation and Maintenance accounts

a) Please explain which accounts other than 5120 and 5125 are affected by the labour dispute settlement costs.
b) Please explain the events of the labour dispute and the breakdown of the $25k cost.

Hearst Power:

a) The labour dispute cost of $25k is redistributed in all labour accounts at year end based on each account ratio towards to total labor expenses.

ALLOCATION OF OVERHEADS				DEC. 31, 2018
Acct.No.	Description	Field labor	% Field labor	GL Entry
11830	Poles, Towers & Fixtures	$ 26,852.36	9.522%	$ 2,380.54
11835	Overhead Conductors & Devices	$ 11,013.57	3.906%	$ 976.39
11840	Underground Conduit - Labor		0.000%	$ -
11845	Underground Conductors & Devices	$ 299.28	0.106%	$ 26.53
11850	Line Transformers - O/H	$ 2,605.22	0.924%	$ 230.96
11850	Line Transformers - U/G	$ 1,016.01	0.360%	$ 90.07
11855	Services (Overhead & Underground)	$ 2,656.34	0.942%	$ 235.49
11860	Meters		0.000%	$ -
11908	Building & Fixtures - Interior - Labor		0.000%	$ -
			15.760%	
34330	Costs & Exp of Merch - Labour	$ 17,866.51	6.336%	$ 1,583.92
34380	Exp of Non-Utility Op - Labour	$ 16,791.66	5.955%	$ 1,488.63
			12.290%	
45020	O/H Dist. - Labour	$ 5,713.21	2.026%	$ 506.49
45025	OH Dist Lines & Feeders - Labour	$ 5,004.20	1.775%	$ 443.64
45055	UG Dist Transformers - Op - Labour	$ 494.90	0.175%	$ 43.87
45070	Customer Premises- Labour	$ 14,305.70	5.073%	$ 1,268.24
45085	Misc. Dist. Exp. - Labour	$ 22,770.26	8.075%	$ 2,018.65
45105	Mtce Supervision & Eng. - Labour	$ 10,664.99	3.782%	$ 945.48
45120	Mtce of Poles - labour	$ 55,783.91	19.782%	$ 4,945.41
45125	Mtce of OH cond - labour	$ 59,189.65	20.989%	$ 5,247.34
45130	Mtce of OH services - labour	$ 4,104.59	1.456%	$ 363.88
45135	OH Dist Lines & Feeders - Labour	$ 1,575.26	0.559%	$ 139.65
45145	Mtce of UG Conduit - Labour	$ 38.04	0.013%	$ 3.37
45155	Mtce of UG Services - Labour	$ 2,737.99	0.971%	$ 242.73
45160	Mtce of Line Transformers - labour	$ 5,964.52	2.115%	$ 528.77
45175	Mtce of Meters - Labour	$ 9,528.92	3.379%	$ 844.77
45310	Meter Reading Expenses - Labour	$ 1,299.92	0.461%	$ 115.24
45320	Collecting - Labour	$ 1,113.69	0.395%	$ 98.73
45410	Community Relations - Labour	$ 2,519.78	0.894%	$ 223.39
45420	Community Safety - Labour	$ 88.00	0.031%	$ 7.82
			71.95%	
		$ 281,998.48	100.00%	$ 25,000.00
45640	Injuries & Damages - Labor Dispute Settlement	$ 25,000.00		
		25,000.00		25,000.00

b) Hearst Power believes it is unable to provide details of the labour dispute due to confidentiality issues.

4-Staff-2

Ref: Exhibit 4, Page 19

In explaining the cost drivers for the maintenance of poles, towers and fixtures (Account 5120) for 2017-2018, Hearst Power states that:

> New Fiber-to-the-home deployment required many poles and fixtures to be brought up to the code for new third party attachments (some costs were the responsibility of third [arties but some were the responsibility of Hearst Power)

OEB staff notes that Account 5125 also contains the exact cost increases for 2017-2018.

a) Please explain the new Fiber-to-the-home deployment project and how it affected Hearst Power.
b) Please clarify the exact amount of costs incurred by Hearst Power versus third parties, as a result of the project.

Hearst Power:

a) When a third party attacher asks to secure an attachment to existing hydro poles, , engineering work is required prior to installation (100% third-party responsibility) and make-ready work is required on the pole for safety clearances and pole stability/security. Make-ready work can involve many tasks and the responsibility of each is identified in the table below, for example:

Task Description	Party responsible
All data collecting, analysis, enginerring work and permits	third-party
Relocation of all or any wires on the pole	third-party
Installation of new ground rods	third-party
Installation of new guy wires and anchors	third-party
Pole change due to insufficient space	third-party
New support pole (guy pole) if required, based on engineering	third-party
Installation of new electricity protection barrier where underground wires run on the pole and no protection is installed	third-party
Any other compliance work as required by ESA or LDC	third-party
Replacing damage LDC ground rods, guy wires, down guy protections and anchors	LDC
Pole in unsafe condition requiring immediate replacement	LDC
Replacing of LDC damaged ptotection barriers for underground wires running on poles	LDC
Retensioning of over sagging LDC owned overhead wires	LDC

b) Hearst Power did not specifically keep track of overhead work that was required in response to the current distribution system safety issues that was identified in the engineering analysis of the poles. Hearst Power fully understood that existing LDC defects on its system should be addressed and paid by the LDC. Hearst Power annually completes repair and maintenance work on its distribution system but not usually at this scale where all issues were identified and required repair in the same year. Hearst Power completed the make ready work in 2018 and the variance from 2017 in account 5020 is $23,774 and in account 5025 is $18,570; the main driver of these variance relates to this work.

All engineering, design and required modifications (make-ready work) to attach the third-party attachment is the responsibility of the third party. In 2017-2018, Hearst Power invoiced $137,571 to the concerned third-party attacher for this work.

4-Staff-3

Ref: Exhibit 4, Page 24

In explaining the cost drivers for Outside Services Employed (Account 5630) for 2015BA-2015, Hearst Power states that:

> 2015BA-2015; Increase of $56,585
> Smart meter third party services that were previously entered in variance accounts by now accounted in 5655 after approved (OEB) smart meter disposal in 2015

OEB staff notes that there was a smart meter disposition approved in 2015 Cost of Service.

a) Please explain the Smart meter third party services and how it relates to the smart meter disposition approved in 2015 Cost of Service.
b) Please confirm if this cost is part of Account 5630 or Account 5655?

Hearst Power:

a) Although the Smart Meter disposition was completed at the same time as the 2015 Cost of Service, each application was done independently (The Smart Meter disposition was not in the 2015 BA numbers). The Board Approved amounts did not include the recurring cost of smart meter readings by third parties and it seems to have been missed in the 2015 COS application. These Smart Meter third party service include invoices from Sensus Canada, ERTH Holdings, Harris NorthStar and Cleo Communication which all relates to Smart Meter data reading and management.

b) Hearst Power confirms this cost is part of Account 5630 as opposed to 5655.

4-Staff-4

Ref: Exhibit 4, Page 24

In explaining the cost drivers for Outside Services Employed (Account 5630) for 2016-2017, Hearst Power states that:

> 2016-2017; Increase of $10,930
> Legal fees provision for Burman Energy's Superior court of justice claim for breach of contract ($35,000 provisional)

OEB staff notes that legal fees for Burman Energy dispute is also included as a cost increase in 2019-2020.

a) Please explain the Burman Energy dispute and how it affects Hearst Power.
b) Please provide a breakdown of costs incurred by Hearst Power due to the Burman Energy dispute.

Hearst Power:

a) Burman Energy is a consulting firm hired by Hearst Power in 2011 to offer turnkey CDM services. In the 2011 to 2015 period, Hearst Power was very minimally involved in CDM services as Burman Energy had been contracted. In 2015, Hearst Power was subject to an in-person meeting due to having achieved very poor CDM results in the 2011 to 2015 period. Burman Energy and Hearst Power's relationship begun to deteriorate at that point; Burman consultant fees were increasing significantly and it was not too long after that Hearst Power terminated the services of Burman Energy. Burman Energy is suing Hearst Power for a substantial amount ($169k) of money stating lost revenues through to 2021.

   3 years after the filing, the Burman Energy claim is still in a "pending" state and the plaintiff has not provided a response to the main question which concerns the possible amount of their claim, which would be the "damages"; a sufficient provision is carried year over year in Hearst Power's books, based on its lawyer recommendation.

   Note: Although Hearst Power had a bad CDM performance in the year 2011-2014, Hearst Power has achieved very good results on the 2016 to 2019 CDM period, where Hearst Power finished 1st in the Province of Ontario in the ratio of achieved target vs IESO target.

b) The fees are as follows:

Year	Description	Amount
2017	Accrual for contract dispute with Burman	$ 35,000.00
2018	Lawyer fees	$ 20,282.25
2019	Lawyer fees	$ 7,682.19
2020	Lawyer fees	$ -
	Total	$ 62,964.44

4-Staff-5

Ref: Exhibit 4, Page 25

In explaining the cost drivers for Regulatory Expenses (Account 5655) for 2019-2020, Hearst Power states that:

> 2019-2020; Increase of $21,630
> Regulatory cost for building a Cost-of-Service application (Engineering Consultant for DSP, Legal fees and Accounting firm financials)

The year over year variance analysis of Administrative and General costs for 2019 actual vs 2020 bridge explains:

> The total increase from 2019 to 2020 in the amount of $103,103 is for the most part attributable to the increase in Administrative and General costs of $72,959. The increase is due to one-time costs in regulatory and outside services expenses including fees, consultants for rate application and Distribution System Plan quantified which represent an increase of $53k in 2020

OEB staff notes that in the Regulatory Costs section, Hearst Power indicates that the regulatory costs specific to the 2021 Cost of Service is $92,000 amortized over 5 years, resulting in an increase of $18,400 for 2021. The regulatory costs include costs of Engineering firm develop the Distribution System Plan, legal review, accounting fees, intervenor costs and public notice costs.

a) Please reconcile the different set of numbers related to Cost of Service costs.
b) Please explain how the increase in Account 5655 for 2019-2020, increase in Administrative and General costs from 2019 to 2020 and the regulatory costs specific to 2021 Cost of Service correlate.
c) Please explain the increase of $53,000 from 2019 to 2020 due to one-time costs in regulatory and outside service expenses, which results in an increase in Administrative and general costs of $72,959.

Hearst Power:

a) The 2019-2020 budget increase of $21,630 was due to having included $18,400 (1/5 of the COS cost) in year 2020, but this was an error and COS regulator cost should have started in year 2021, not 2020.

The revised 2020 numbers show that the COS cost in year 2020 were transferred in “prepayments” to be split in years 2021 to 2025. Also, in year 2020, there was an increase of $6k in regulatory consultant costs due to new OEB regulations for “Class B Global Adjustment Deferral” which required changes to IESO settlement for account 1588 and 1589.

As for the 2019 to 2020 budgeted increase of $33,464 in Outside Services provided, it included the previous year cost + inflation and the following new budgeted costs:

New Outside Service Budgeted for 2020	2020 Budgeted	2020 Actual	Note
Cybersecurity consultant	$10,000	0$	Did not proceed, impacted by COVID-19 Emergency
Billing software upgrades due to OEB prescribed changes	$5,000	0$	No fees charged for upgrades. Covered under annual fees.
“Green Button” implementation (Ministry of Energy)	$5,000	0$	Seems to have been put on hold by the Ministry of Energy (no updates) due to COVID-19 Emergency
MIST meter programming and readings	$5,500	0$	Did not proceed, impacted by COVID-19 Emergency
Legal Fees for Burman Energy’s Claim	$8,000	0$	Did not proceed, impacted by COVID-19 Emergency

The updated values for 2020 will show much closer actuals to 2019 than what was budget because many services we delayed due to the COVID-19 Emergency. The 2020 actuals include a single one-time increase in the amount of $3,795 for programming and management for converting to a IP phone system and incorporating data collection capability for OEB RRR 2.1 reporting on Telephone Accessibility.

b) See response to question a)

c) The $53k increase relates to the 2020 budgeted outside services describe in the table in a), in the amount of $33,500 and an amount of $18,400 representing one fifth of the COS application cost ($92k). This to be revised as most of the 2020 budgeted outside services were deferred due to the COVID-19 emergency and the $18,400 of COS fees was remove from 2020 and started the 5-year amortization in 2021 instead. Therefore, the variances 2019 to 2020 is minimal considering these deferrals of costs from 2020 to future years.

4-Staff-6

Ref: Exhibit 4, Page 26
In explaining year over year variance analysis for 2015 OEB-approved vs 2015 actual, Hearst Power states that:

> The total OM&A costs in 2015 were $196,755 greater than 2015 OEB Approved amount. The major reasons for the variance between OEB Approved and Actual was due to the approval to transfer smart meter disposals in the amount of $217,302.

OEB staff notes that in its 2015 Cost of Service, Hearst Power was approved recovery of a net deferred revenue requirement for its smart meter program of $511,738 through the rate riders as calculated by Hearst Power over four years. From the total amount, the amount under Operating Expenses and related Interest is $223,698.

a) Please confirm the $217,302 amount disposed in 2015 was the Operating Expenses amount approved in 2015 Cost of Service in full.

Hearst Power:

a) Hearst Power confirms that the $217,302 amount disposed in 2015 in Maintenance of Meters was a Smart Meter Operating Expense amount approved in the 2015 Smart meter disposal included in the 2015 Cost of Service application covered under EB-2014-0080.

   As per a Net income analysis provided to the OEB in previous filings (see below table), the removal of the Smart meter disposition in the 2015 number brings the total numbers total the Board approved amounts.

Hearst Power Distribution Company Limited	
Net income analysis	
December 31, 2015	
TOTAL INCOME AND OTHER COMPREHENSIVE INCOME AFTER DISPOSITION OF SMART METERS VARIANCE ACCOUNT	**(213,443)**
Smart meters recoveries	(171,620)
Smart meters amortization expense	215,373
Maintenance of smart meters	217,303
Carrying charges on smart meter capital and recovery variance account	25,894
Carrying charges on smart meter OM&A variance account	18,336
TOTAL INCOME AND OTHER COMPREHENSIVE INCOME BEFORE DISPOSITION OF SMART METERS VARIANCE ACCOUNT	**91,843**

4-Staff-7

Ref: Exhibit 4, Page 46
Ref: Exhibit 4, Page 23
OEB staff notes that from 2016 to 2017, the total salary and wages for non-management employees increased from $325,304 to $367,873 according to Appendix 2-K.

a) Please explain the increase from 2016 to 2017 and from 2019 to 2020 of the total salary and wages for non-management employees.

Hearst Power:
a) The increase is directly related to human resource changes. Either from retirement to new apprentice or temporary vacancy. The table below illustrates the non-management employees in staff in each of the different years:
b)

HPDC Workforce											
2015		2016		2017		2018		2019		2020	
Workers	Yr	Workers	Yr	Workers	Yr	Workers	Yr	Workers	Yr	Workers	Yr
(Lead)	1	(Lead)	1	(Lead)	1	(Lead)	1	(Lead)	1	(Lead)	1
(Lineman)	0.8	(Lineman)	1	(Lineman)	1	(Lineman)	1	(Lineman)	1	(Lineman)	1
(Lineman)	1	(App lvl 1)	1	(App lvl 3)	0.25	(App lvl 3)	0.75	(App lvl 4)	1	(App lvl 4)	1
(App lvl 0)	1	(App lvl 0)	0.5	(App lvl 2)	0.75	(App lvl 3)	1	(App lvl 0)	0.5	(App lvl 1)	1
				(App lvl 1)	1						
	3.8		3.5		4		3.75		3.5		4

To better explain the table above, in year 2016, Hearst Power employe 1 Leadhand for 1 full year, 1 certified Lineman for 1 full year, 1 apprentice lineman level 1 for 1 full year and 1 apprentice Lineman (beginner) for 6 months. Also, it is to be noted the salary of each Powerlineman is determined based on a unionized scale of qualification (ie: An apprentice level 2 is paid more than an apprentice level 1).

4-Staff-8

Shared Services and Corporate Cost Allocation
Ref: Exhibit 4, Page 49
Hearst Power has provided its Corporate Cost Allocation and Shared Service information at Exhibit 4, page 49, however has not provided the accompanying intercorporate agreement.

a) Please provide the Inter-corporate Service Agreement.
b) How were the shared service costs determined?
c) Please provide any cost allocation study performed to support the figures shown in Appendix 2-N.
d) Has Hearst Power included the costs of services provided to Hearst Power from the Town of Hearst in its evidence?

e) Please provide more details on the Third-Party attachments (Telecom) charge paid by Hearst Connect Corporation to Hearst Power, starting in 2017.

Hearst Power:

a) Please see attached latest Inter-corporate agreements. One relates to the relation with the Corporation of the Town of Hearst and the other, to the Corporation of Hearst Connect.

b) The shared services costs are determined as explained the tables in Exhibit 4 page 51 to 57 (Appendix 2-N), in the column entitled “Pricing Methodology”.

c) The cost allocations are based on actual cost incurred, except for office rental charges which are based on current local market rates.

d) Hearst Power has included the cost of the services provided to Hearst Power from the Town of Hearst in Appendix 2-N, column entitled “Cost for the Service”, in rows that include “Town of Hearst” in column entitled “From”.

e) In 2017, due to the fact that the internet in Hearst was limited to around 5 mbps, the Corporation of the Town of Hearst incorporated a new company to offer Fiber to the Home Services in Hearst. The project was backed by a $1.4M grant from the Province of Ontario.

   During the first year (2017), Hearst Connect paid Hearst Power mostly for engineering costs and design work in order for them to build a plan for their attachment on poles owned by Hearst Power, Hydro One and Bell.

   During the second year of existence, Hearst Connect paid Hearst Power for make-ready work on hydro poles so that they are given authorization and a permit to attach as per the code and provided stamped engineered drawings. Hearst Connect did start to install attachments in Hearst Power in late 2018 where they finished the year with 244 pole attachments and were billed $3,632.28 in early 2019.

   In the year 2019, Hearst Connect continued their fiber to the home deployment and finished the year with 677 pole attachments, mainly due to the purchase of an existing Attacher (Eastlink) in the Hearst area. In 2019, Hearst Power invoiced $20,321 for pole rental fees.

   In 2020, Hearst Power invoiced $30,127 in pole rental fees to Hearst Connect.

   Note that Hearst Power is following the OEB’s letter Accounting Guidance on Wireline Pole Attachment Charges, dated July 20, 2018, where some pole rental fees are recorded in account 1508 until the rate of $44.50 is approved in this application.

4-Staff-9

Ref: Exhibit 4, Page 85
Ref: Exhibit 8, Page 66

Hearst Power states on Page 85 of Exhibit 4 that:

> Funding and expenditures for the delivery of IESO Contracted Province-Wide Programs are kept separate and tracked in Non-Distribution Revenue Accounts in accordance with the guidance in Chapter 5, Accounting Treatment of the CDM Code. Therefore, CDM activities are not included in the calculation revenue requirement or revenue offsets.

Hearst Power also states Page 66 of Exhibit that:

> Account 4375 and 4380 show material increases due to the ongoing management of LDC Provincial programs, namely a Conservative Demand Management program and the Affordability Fund Program which account for $697,798 in revenues (account 4375) and $612,441 in expenses (account 4330).

a) Please provide a more detailed explanation regarding the type of revenues and expenses captured in accounts 4375 and 4380, respectively.
b) Please confirm the reference to account 4330 mentioned above is a typo and Hearst Power is referring to account 4380.
c) Please reconcile the explanation in the above-noted first reference (that CDM activities are not included in revenue requirement or revenue offsets) with the statement in the above-noted second reference (that Accounts 4375 and 4380 contain CDM revenues and expenses), given that Accounts 4375 and 4380 form part of the total revenue offsets (and thus, revenue requirement).

Hearst Power:

a) Account 4375 and 4380 keep track of revenues and expenses for Street Lighting, Water billing, MicroFit maintenance, CDM and conservation pilot projects, the Affordability Fund Program and Vendor services provided to others on non-distribution related issues.

c) Hearst Power confirms the reference to 4330 is a typo and should show 4380.

d) Hearst power confirms that the net of the revenues and expenses related to non-utility operations are treated as other revenues and as such are removed from the revenue requirement.

4-Staff-10

Ref: **LRAMVA Workform, Tab 5**
The electricity savings for the 2018 Save on Energy Coupon, Save on Energy Audit Funding, and Save on Energy Small Business Lighting programs do not align with the April 2019 IESO Participation and Cost Report.

(a) Were all results from the 2018 Save on Energy Coupon, Save on Energy Audit Funding, and Save on Energy Small Business Lighting programs reported to the IESO for incorporation into the April 2019 Participation and Cost Report?
(b) Please identify where the values for the 2018 Save on Energy Coupon, Save on Energy Audit Funding, and Save on Energy Small Business Lighting programs in Tab 5 of the LRAMVA Workform were derived from. Should any additional documents be filed in support of the response, please ensure that all consumer confidential information is treated in accordance with Rule 9A of the OEB's Rules of Practice and Procedure.

Hearst Power:

a) All savings were reported to IESO for incorporation into the April 2019 Participation and Cost Report.

b) Savings for the 2018 Coupon program should be 0 kWh, 0 kWh for the Energy Audit Funding Program and 33,105 kWh for the Save on Energy Small Business Lighting Program as reported in the April 2019 Participation and Cost Report. A revised LRAMVA Workform is attached.

4-Staff-11

Ref: LRAMVA Workform, Tab 5
Hearst Power is claiming a 45,965 kWh electricity saving in 2017 for an Enersource Hydro Mississauga Inc. Ontario Clean Water Agency P4P Conservation Fund Pilot Program. As stated in Tab 5 in the LRAMVA Workform, this pilot program is funded by the OCWA/IESO through the IESO Conservation Fund.

(a) Please explain how Hearst Power achieved electricity savings through an Ontario Clean Water Agency Conservation Pilot Program. Please provide any relevant calculations to justify the electricity savings claimed.
(b) This Enersource Hydro Mississauga Inc. Ontario Clean Water Agency P4P Conservation Pilot Program has been funded through the IESO Conservation Fund. Please explain why an additional financial recovery claim is being made through the LRAMVA.

Hearst Power:

a) The Town of Hearst's water filtration plant is managed by the Ontario Clean Water Agency (OCWA). The facility was enrolled in the Ontario Clean Water Agency P4P Conservation Fund Pilot and achieved savings through the pilot program. Savings were verified by the IESO and individual facility savings were attributed to the LDC in which the facility was located. Final and verified savings for the Ontario Clean Water Agency Conservation Pilot Program can be found in the IESO Program Participation & Cost Report dated April 15, 2019.

b) The Town of Hearst water plant facility participated in the Ontario Clean Water Agency Conservation Program ultimately reducing their kWh usage through a CDM Program. This reduction in usage resulted in a variance between the OEB-Approved forecast and actual results at the customer level.

4-Staff-12

Ref: LRAMVA Workform, Tab 8
Ref: LRAMVA Workform, Tabs 4 and 5

(a) Please populate Tab 8 of the LRAMVA Workform to include the required details for all Street Lighting CDM projects completed since 2011.
(b) Please identify under which program the Street Lighting savings have been included in on Tabs 4 and 5 of the LRAMVA Workform.

Hearst Power:

a) A revised LRAMVA Workform is attached.

b) The Town of Hearst Street lighting project was included under the 2015 Efficiency: Equipment Replacement Incentive Initiative program savings on Tab 5.

4-Staff-13

Ref: LRAMVA Workform, Tab 1
Ref: LRAMVA Workform, Tab 2

In Tab 2 of the LRAMVA Workform, the Sentinel rate class has an LRAMVA Threshold assigned from Hearst Power's 2015 Cost of Service Application. However, on Tab 1 of the LRAMVA Workform, there are no actual savings allocated to the Sentinel rate class.

(a) Please confirm whether there are any actual CDM savings that can be allocated to the Sentinel rate class?
(b) If there are no actual CDM savings for the Sentinel rate class, please explain why no such projects have been initiated considering the fact that a corresponding LRAMVA Threshold has been incorporated in Hearst Power's electricity rates.

Hearst Power:

a) No actual CDM savings can be allocated to the Sentinel rate class as no IESO CDM applications were received for this class.

b) Hearst Power can only state that no Sentinel rate class have applied under the IESO CDM programs for Sentinel lights. Sentinel lights customer may have transitioned to LED sentinel lights without the IESO CDM incentives, therefore, these would not be recorded and taken into consideration.

4-Staff-14

Ref: EB-2019-0040 Application, Section 12

In its 2020 electricity IRM application, Hearst Power stated the following in Section 12:

> Hearst Power is not filing the LRAMVA Workform as part of this application. Hearst Power proposes to postpone the disposition of LRAMVA claim to its next Cost of Service where it will have the opportunity to question the methodology behind the IESO results and possibly propose an alternative that would be better suited to Hearst Power.

Upon review of the present Cost of Service application, there does not appear to be any questioning of the methodology behind the IESO results nor an alternative that would be better suited to Hearst Power.

(a) Please confirm that Hearst Power accepts the IESO results, including the methodology employed, and does not propose an alternative that would be better suited to Hearst Power.
(b) If Hearst Power intends on questioning the methodology behind the IESO results or propose an alternative that would be better suited to Hearst Power in the future, please discuss the rationale and timing of such a proposal?

Hearst Power:

a) Hearst Power accepts the IESO results, as have other utilities.

b) HPDC does not intend to contest the methodology behind the results at a future time.

4-Staff-15

Ref: LRAMVA Workform, Tab 1

(a) Please complete the 'Previous LRAMVA Application' and 'Current LRAMVA Application' sections of Tab 1 of the LRAMVA Workform.

Hearst Power:

a) Please see LRAMVA model filed along with these responses

4-Staff-16

Ref: LRAMVA Workform, Tab 3-a

Tab 3-a of the LRAMVA Workform requires an LDC to demonstrate their rate class allocations and the supporting calculations, as required. However, Tab 3-a of the LRAMVA Workform filed is blank.

(a) Please complete Tab 3-a of the LRAMVA Workform to include rate class allocation and the supporting calculations, as required.

Hearst Power:

a) Please refer to updated LRAMVA Workform.

4-Staff-17

(a) Please provide updated IRM Model Rate Generator and LRAMVA Workforms reflecting any changes required in response to OEB staff interrogatories, as required. Please indicate all changes in Tab 1-a of the LRAMVA workform.

Hearst Power:

a) HPDC has not updated any IRM Rate Generator model as part of this process and a revised LRAMVA model is being file along with these responses.

4.0 -VECC-32

Reference: Exhibit 4, Pages 13-

a) Please update Table 5 to include actual 2020 results and any necessary changes for 2021.
b) Please update Appendix 2-JC (OM&A by Program) for the 2020 actual results and any necessary changes for 2021.
c) Please explain why the 2015 Board approved amounts for each of these tables is different ($1,019,224 and $1,018,127).

Hearst Power:

See updated table below

a)

Reporting Basis		Board Appr.							
Account	**Description**	**2015**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
	5020-Overhead Distribution Lines and Feeders - Operation Labour	$4,209	$10,681	$3,295	$13,103	$9,328	$16,930	$5,106	$15,375
	5025-Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	$98,419	$43,742	$47,020	$51,461	$61,011	$64,377	$27,540	$72,775
	5030-Overhead Sub transmission Feeders - Operation	$0	$0	$0	$0	$0	$0	$0	$0
	5035-Overhead Distribution Transformers- Operation	$0	$120	$187	$7,320	$0	$7	$266	$0
	5040-Underground Distribution Lines and Feeders - Operation Labour	$0	$0	$0	$6,744	$0	$0	$475	$0
	5045-Underground Distribution Lines and Feeders - Operation Supplies and Expenses	$544	$634	$50	$39	$240	$2,668	$3,713	$0
	5050-Underground Sub transmission Feeders - Operation	$0	$0	$0	$0	$242	$0	$0	$0
	5055-Underground Distribution Transformers - Operation	$0	$302	$115	$7,017	$967	$4,233	$107	$0
	5060-Street Lighting and Signal System Expense	$0	$0	$0	$0	$0	$0	$0	$0
	5065-Meter Expense	$4,748	$6,673	$2,017	$3,849	$1,934	$715	$107	$1,538
	5070-Customer Premises - Operation Labour	$0	$40,032	$21,231	$25,614	$23,357	$32,704	$27,901	$38,950
	5075-Customer Premises - Materials and Expenses	$0	$439	$320	$169	$580	$987	$2,168	$769
	5085-Miscellaneous Distribution Expense	$31,368	$61,791	$42,214	$51,682	$54,324	$28,494	$72,855	$32,800
	5095-Overhead Distribution Lines and Feeders - Rental Paid	$5,475	$7,055	$9,300	$9,315	$9,383	$13,782	$18,494	$15,375
	5096-Other Rent	$1,097	$3,650	$3,250	$4,100	$4,100	$4,175	$3,700	$4,203
Total - Operations		$145,860	$175,120	$129,461	$180,412	$165,467	$169,073	$162,432	$181,784
Account									
	5105-Maintenance Supervision and Engineering	$7,788	$17,829	$16,316	$14,731	$17,413	$18,341	$16,332	$19,988
	5120-Maintenance of Poles, Towers and Fixtures	$75,000	$41,300	$75,421	$77,095	$100,870	$49,405	$61,780	$81,600
	5125-Maintenance of Overhead Conductors and Devices	$117,067	$39,377	$80,471	$80,665	$99,235	$65,327	$78,002	$81,600
	5130-Maintenance of Overhead Services	$25,000	$3,971	$14,652	$4,549	$7,084	$15,532	$34,400	$15,375
	5135-Overhead Distribution Lines and Feeders - Right of Way	$0	$18,530	$12,710	$9,513	$2,572	$14,093	$12,034	$8,670
	5145-Maintenance of Underground Conduit	$562	$565	-$51	$1,994	$861	$18,355	$981	$5,100
	5150-Maintenance of Underground Conductors and Devices	$2,733	$6,265	$7,382	$3,566	$2,898	$22,149	$1,594	$5,100
	5155-Maintenance of Underground Services	$24,705	$8,613	$9,236	$4,191	$4,470	$24,163	$9,247	$15,375
	5160-Maintenance of Line Transformers	$60,000	$61,057	$59,271	$55,833	$63,866	$61,253	$63,251	$67,650
	5170-Sentinel Lights - Labour	$0	$0	$0	$0	$0	$0	$0	$0
	5175-Maintenance of Meters	$9,845	$225,227	$6,599	$5,608	$18,214	$17,069	$4,992	$10,000
Total - Maintenance		$322,700	$422,733	$282,006	$257,745	$317,482	$305,687	$282,611	$310,458
Account									
	5310-Meter Reading Expense	$22,602	$23,405	$18,353	$18,453	$18,703	$16,649	$15,953	$18,194
	5315-Customer Billing	$206,421	$208,062	$191,589	$213,266	$201,465	$206,542	$230,337	$224,475
	5320-Collecting	$26,160	$42,892	$42,890	$41,748	$42,048	$44,427	$42,808	$47,150
	5330-Collection Charges	$1,618	$1,447	$1,139	$1,333	$781	$711	$823	$820
	5335-Bad Debt Expense	$14,557	$7,006	$11,302	$13,838	$3,950	$11,412	$10,678	$13,325
	5340-Miscellaneous Customer Accounts Expenses	$10,892	$21,420	$22,321	$22,487	$22,914	$23,361	$23,770	$24,600
Total - Billing and Collecting		$282,250	$304,232	$287,594	$311,125	$289,861	$303,101	$324,369	$328,564
Account									
	5410-Community Relations - Sundry	$0	$3,958	$4,488	$3,870	$4,114	$1,763	$3,639	$2,563
	5415-Energy Conservation	$0	$2,317	$0	$0	$0	$0	$0	$0
	5420-Community Safety Program	$0	$3,175	$1,874	$135	$1,372	$0	$0	$0
	5515-Advertising Expense	$8,000	$5,618	$2,727	$2,058	$3,561	$2,133	$1,651	$2,500
Total - Community Relations		$8,000	$15,068	$9,089	$6,063	$9,048	$3,895	$5,290	$5,063

Account									
	5605-Executive Salaries and Expenses	$12,500	$11,300	$11,852	$10,328	$11,937	$12,324	$12,944	$13,838
	5610-Management Salaries and Expenses	$0	$0	$0	$0	$88,687	$88,177	$0	$103,425
	5615-General Administrative Salaries and Expenses	$101,250	$92,121	$100,223	$100,551	$0	$0	$102,476	$0
	5620-Office Supplies and Expenses	$6,500	$7,572	$6,221	$9,206	$12,172	$9,842	$9,883	$10,763
	5630-Outside Services Employed	$27,000	$83,585	$104,439	$115,368	$122,649	$96,536	$94,069	$123,000
	5635-Property Insurance	$6,764	$6,153	$9,105	$9,507	$10,157	$9,093	$9,094	$10,250
	5655-Regulatory Expenses	$59,300	$49,644	$66,689	$45,859	$45,702	$44,646	$50,350	$64,650
	5660-General Advertising Expenses	$0	$92	$0	$0	$0	$0	$0	$0
	5665-Miscellaneous General Expenses	$29,000	$30,526	$22,955	$29,655	$29,196	$38,197	$15,765	$35,000
	5670-Rent	$13,600	$13,380	$13,608	$13,880	$16,172	$14,398	$14,672	$15,580
	5680-Electrical Safety Authority Fees	$2,500	$2,457	$2,632	$2,898	$2,686	$2,778	$2,603	$3,075
	6205-Donations	$0	$0	$0	$0	$500	$0	$0	$0
	6205-Sub-account LEAP Funding	$2,000	$2,000	$2,000	$0	$0	$4,000	$2,000	$2,000
	6305-Extraordinary Income	$0	-$5	-$46	$0	$0	$0	$0	$0
Total - Administrative and General Expenses		$260,414	$298,826	$339,676	$337,252	$339,857	$319,991	$313,856	$381,580
Total OM&A		$1,019,224	$1,215,979	$1,047,826	$1,092,597	$1,121,716	$1,101,747	$1,088,558	$1,207,448
Adjustments for non-recoverable items									
	Non Recoverable donations					$500			
Total Recoverable OM&A		$ 1,019,224	$ 1,215,979	$ 1,047,826	$ 1,092,597	$ 1,121,216	$ 1,101,747	$ 1,088,558	$ 1,207,448

Reporting Basis		Test Year Versus Last Rebasing		Test Year Versus Most Current Actuals	
Account	**Description**	**Variance ($)**	**Percentage Change (%)**	**Variance ($)**	**Percentage Change (%)**
	5020-Overhead Distribution Lines and Feeders - Operation Labour	$11,166	265.29%	-$ 1,555	-9.19%
	5025-Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	-$25,644	-26.06%	$ 8,398	13.05%
	5035-Overhead Distribution Transformers- Operation	$0		-$ 7	-100.00%
	5045-Underground Distribution Lines and Feeders - Operation Supplies and Expenses	-$544	-100.00%	-$ 2,668	-100.00%
	5055-Underground Distribution Transformers - Operation	$0		-$ 4,233	-100.00%
	5065-Meter Expense	-$3,211	-67.62%	$ 822	114.96%
	5070-Customer Premises - Operation Labour	$38,950		$ 6,246	19.10%
	5075-Customer Premises - Materials and Expenses	$769		-$ 218	-22.09%
	5085-Miscellaneous Distribution Expense	$1,432	4.57%	$ 4,306	15.11%
	5095-Overhead Distribution Lines and Feeders - Rental Paid	$9,900	180.82%	$ 1,593	11.56%
	5096-Other Rent	$3,106	283.09%	$ 28	0.66%
Total - Operations		$35,924	24.63%	$ 12,711	7.52%
Account					
	5105-Maintenance Supervision and Engineering	$12,200	156.64%	$ 1,647	8.98%
	5120-Maintenance of Poles, Towers and Fixtures	$6,600	8.80%	$ 32,195	65.16%
	5125-Maintenance of Overhead Conductors and Devices	-$35,467	-30.30%	$ 16,273	24.91%
	5130-Maintenance of Overhead Services	-$9,625	-38.50%	-$ 157	-1.01%
	5135-Overhead Distribution Lines and Feeders - Right of Way	$8,670		-$ 5,423	-38.48%
	5145-Maintenance of Underground Conduit	$4,538	807.47%	-$ 13,255	-72.21%
	5150-Maintenance of Underground Conductors and Devices	$2,367	86.61%	-$ 17,049	-76.97%
	5155-Maintenance of Underground Services	-$9,330	-37.77%	-$ 8,788	-36.37%
	5160-Maintenance of Line Transformers	$7,650	12.75%	$ 6,397	10.44%
	5175-Maintenance of Meters	$155	1.57%	-$ 7,069	-41.42%
Total - Maintenance		-$12,243	-3.79%	$ 4,771	1.56%
Account					
	5305-Supervision	$0		$ -	
	5310-Meter Reading Expense	-$4,408	-19.50%	$ 1,545	9.28%
	5315-Customer Billing	$18,054	8.75%	$ 17,933	8.68%
	5320-Collecting	$20,990	80.24%	$ 2,723	6.13%
	5330-Collection Charges	-$798	-49.31%	$ 109	15.35%
	5335-Bad Debt Expense	-$1,232	-8.46%	$ 1,913	16.76%
	5340-Miscellaneous Customer Accounts Expenses	$13,708	125.85%	$ 1,239	5.31%
Total - Billing and Collecting		$46,314	16.41%	$ 25,463	8.40%
Account					
	5405-Supervision	$0		$ -	
	5410-Community Relations - Sundry	$2,563		$ 800	45.36%
	5515-Advertising Expense	-$5,500	-68.75%	$ 367	17.23%
	5520-Miscellaneous Sales Expense	$0		$ -	
Total - Community Relations		-$2,938	-36.72%	$ 1,167	29.96%
Account					
	5605-Executive Salaries and Expenses	$1,338	10.70%	$ 1,514	12.28%
	5610-Management Salaries and Expenses	$103,425		$ 15,248	17.29%
	5615-General Administrative Salaries and Expenses	-$101,250	-100.00%	$ -	
	5620-Office Supplies and Expenses	$4,263	65.58%	$ 921	9.36%

	5625-Administrative Expense Transferred/Credit	$0		$ -	
	5630-Outside Services Employed	$96,000	355.56%	$ 26,464	27.41%
	5635-Property Insurance	$3,486	51.53%	$ 1,157	12.73%
	5655-Regulatory Expenses	$5,350	9.02%	$ 20,004	44.80%
	5665-Miscellaneous General Expenses	$6,000	20.69%	-$ 3,197	-8.37%
	5670-Rent	$1,980	14.56%	$ 1,182	8.21%
	5680-Electrical Safety Authority Fees	$575	23.00%	$ 297	10.69%
	6205-Sub-account LEAP Funding	$0	0.00%	-$ 2,000	-50.00%
Total - Administrative and General Expenses		$121,166	46.53%	$ 61,589	19.25%
Total OM&A		$188,224	18.47%	$ 105,700	9.59%
Adjustments for non-recoverable items					
Total Recoverable OM&A		$ 188,224	18.47%	$ 105,700	9.59%

b) See below update to Appendix 2-JC OM&A Programs (2020 Actuals)

Programs	2019	2020	2021
Reporting Basis			
Customer Focus			
360 Communication	2,133	1,651	2,500
Customer Service, Mailing Costs, Billing and Collections[2]	301,531	323,574	326,001
Bad Debts	11,412	10,678	13,325
Locates	$33,691	$30,070	$39,719
Sub-Total	**348,767**	**365,973**	**381,545**
	#	#	#
Operational Effectiveness	#	#	#
Meters	17,785	5,098	11,538
Overhead lines	190,048	175,576	209,170
Underground Lines	71,568	16,116	25,575
Operations & engineering, Inspection drafting & design construction services	18,341	16,332	19,988
Distribution Transformers	61,253	63,517	67,650
Poles Towers & Fixtures	49,405	61,780	81,600
Warehouse and garage building costs	28,494	72,855	32,800
Admin, Legal, Professional and Insurance Services[1]	109,594	124,514	127,513
- Other (Misc. Gen. Expenses, Rent)	56,770	34,137	54,783
Sub-Total	**603,258**	**569,925**	**630,617**
	#	#	#
Public & Regulatory Responsiveness	#	#	#
Regulatory & Compliance[1]	143,960	147,022	190,725
Community and Public Assistance	1,763	3,639	2,563
Sub-Total	***145,723***	***150,661***	***193,288***
Miscellaneous			
Special Purpose Charge as per OEB	#	#	#
Donations - LEAP Funding	4,000	2,000	2,000
	#	#	#
	#	#	#
Sub-Total	***4,000***	***2,000***	***2,000***
	#	#	#
Total	**1,101,748**	**1,088,558**	**1,207,450**

c) The correct amount is shown in Table 5 as $1,019,224. The Appendix 2-JC (OM&A by Program) is missing $1,097 under “Other” (rent) which should show $43,697 instead of $42,600.

4.0 VECC-33

Reference: Exhibit 4, Pages 13- Table 5

a) Please explain how the bad debt expense for 2021 was estimated.
b) Does the bad debt expense include and amounts anticipated due to the ongoing pandemic?

Hearst Power:

a) The bad debt estimate of $13,325 for 2021 is a forecast based on previous years + a slight increase considering the current economic situation (COVID-19) which is less then ideal.

b) The COVID crisis did impact Hearst Power but mostly in electricity sales and distribution revenues. With the lower electricity rates, and all the government assistance, most customers are able to pay their hydro bills. The bad debt forecasted is bearing in mind the ongoing pandemic but also considering the government assistance. The bad debt forecasted is $3k higher than the 3-year (2017-2019) average.

4.0 -VECC-34

Reference: Exhibit 4, Page 19

2018 – 2019 ; Decrease of -$25,830
Labor cost decrease in 2019 due to 1 less worker for 6 months and busy with third party underground fiber expansion projects as well a road reconstruction projects, therefore offsetting some labor cost to account 5145, 5150, 5155.

a) Does Hearst Power do third party work for telecommunications companies? If so please explain the nature and revenue associated with this work.

Hearst Power:

a) Hearst Power will assist any telecom company with industry related tasks to complete if such company requests service and accepts Hearst Power's fees.

   In the 2019 instance referred above, the third-party underground fiber expansion project by a Telecom provider and the roads reconstruction (including new water and sewer piping) by the Town of Hearst required a very significant amount of electricity wire locates to be done and also often required the assistance of a Hearst Power Powerlineman to supervise digging around electricity lines.

   The road reconstruction was completed by privately owned construction companies which sometimes do not report underground wires being hit by excavators. Therefore, when electricity wire coverings are hit/damage just so slightly by an excavator, the electricity wires will start corroding and over time will not be able to work. Furthermore, when backfilling an underground electricity wire, proper backfill need to be used for the wire to not brake or get damage with frost as in Northern Ontario, in-ground frost can easily go 8' deep in cold winters. If Hearst Power sees that a construction company has failed its obligation, Hearst Power will charge the repair fees to this company. Most of the time, the construction company preferred not to have Hearst Power supervising but Hearst Power management often felt a need for supervision to protect its assets.

With the road reconstruction and new water and sewer mains installation, the Hearst Power 45-year-old underground system was exposed to some strain and repair work was required along the way to repair exposed issues.

4.0 -VECC-35

Reference: Exhibit 4, Page 19

2019 – 2020 ; Increase of $38,505

Employee salaries allocated to this account due to COVID-19 during time where there was a lockdown in the Province. Increase in this account is offset by lower O&M other accounts (5135, 5145, 5150, 5155, 5175) when compared to previous years.

a) Please explain more fully why there was an increase in salaries due to COVI-19.

Hearst Power:

a) There was no actual increase in salaries, Hearst Power simply recorded the salary expense in a different expense account due to the fact that employees, whose routine is to complete maintenance work on the distribution system in a normal year, were sometimes, out of necessity, placed on standby and could only perform administrative tasks in response to the declaration of the COVID-19 Emergency starting in March 2020.

4.0 -VECC-36

Reference: Exhibit 4, Pages 19-

a) The evidence speaks of "*labour dispute settlement costs spread over multiple account*(s)". What was the total cost of this settlement and over what years was this cost spread?

Hearst Power:

a) The total cost was $25k in 2018. For more details, please refer to response to question 4-Staff-1.

4.0 -VECC-37

Reference: Exhibit 4, Pages 24,29

a) Please provide the amounts for each year between 2015 and 2021 in which a portion of a Hearst Power employee's compensation costs were being transferred to CDM related work and therefore not recorded as part of the regulatory OM&A for rates (i.e., not shown in Appendix 2-JA etc.).
b) Is the total incremental cost of non-regulated activities beginning in 2020 10k? (as described at page 29)?

Hearst Power:

a) The table below illustrate that recorded employee expense related to CDM in various year:

Year	Sum of all employees salaries transferred from OM&A to CDM
2021	$ -
2020	$ -
2019	$ 12,423.02
2018	$ 5,005.00
2017	$ -
2016	$ -
2015	$ -

b) In 2019, Hearst Power went through a IESO CDM audit and completed a local Pilot CDM project, thus the reason for transferring salaries from OM&A to CDM expenses. In 2020, no salaries were transferred from OM&A to CDM, thus the increase in some accounts from 2019 to 2020. The incremental cost of CDM non-regulated activities beginning in 2020 is $12,423.02 when compared to 2019.

4.0 -VECC-38

Reference: Exhibit 4, Pages 61

a) If Hearst is a member of the Electricity Distributors Association, please provide the annual membership costs for the years 2015 through 2021 (forecast).

b) Please provide the annual cost of any other industry related memberships.

Hearst Power:

a) Hearst Power is a member of the EDA and the annual membership paid/forecast is the following:

Year	EDA annual fee
2021	$ 9,800.00
2020	$ 9,700.00
2019	$ 9,500.00
2018	$ 9,300.00
2017	$ 9,100.00
2016	$ 9,000.00
2015	$ 8,900.00

b) Hearst Power is also part of Utility Standards Forum (USF) with provide most of the engineer's specs for installing and maintaining an electricity distribution system and meeting the required ESA regulations. USF is also an exchange platform (forum) where regulatory, billing, IT, engineering and other LDC related topis are discussed. Yearly fees are as per the following:

Year	USF annual fee
2021	$ 8,750.00
2020	$ 7,950.00
2019	$ 8,750.00
2018	$ 8,750.00
2017	$ 8,750.00
2016	$ 8,750.00
2015	$ 8,750.00

4.0 -VECC-39

Reference: Exhibit 4, Pages 64- & Exhibit 2, page 66

"*HPDCL has relied on AESI who in turn relied on the OEB's filing requirements Chapter 5 to guide its presentation of its policies, practices, and decision-making processes*" (Ex 2/pg.66)

a) The AESI report I is entitled <u>Ontario Regulation 22/04P, Sections 4 to 8</u>. Is this report undertaken as a requirement of the Electrical Safety Authority? If so how is this determinative of the Board's filing requirements?

b) If the AESI Report is for purposes of ESA requirements why is it included in the one-time costs of this application?

c) Please confirm (or correct) that is the AESI remote audit report filed at page 182 of Exhibit 2 is the one that cost $36,000 as reported in Table 22

Hearst Power:

a) AESI consultants are hired to complete two different items for Hearst Power.
   1) One annually recurring item is, as required by Ontario Regulation 22/04, Section 13, the Hearst Power 2020 audit report ESA (Electricity Safety Association). It is a regulatory compliance component that is shown yearly on each LDC's scorecard under row "Level of Compliance with Ontario Regulation 22/04". This report cost approximately $2,000-2,500 per year and is reported in OM&A expenses.
   2) The second item is the actual complete Distribution System Plan (DSP), which includes the latest copy of the document in #1 above (2020 audit report). The DSP is built using the Board's filing requirements.

b) The "AESI" amount shown in Table 2 in Exhibit 4, page 64 represents the related cost for the engineering components of the Cost-of-Service applications, including the construction of the Distribution System Plan.

c) No, the report filed on page 182 of Exhibit 2 is the annual compliance report as described in item #1 in response a) above and did not cost $36k. This COS budgeted amount of $36k include the cost for all engineering work including building the Distribution System Plan and responding to interrogatory questions.

   The questions received from OEB staff related to the DSP (questions 2-Staff-2 to 2-Staff-20), will require a significant amount of data collection and in-depth analysis to answer. Hearst Power does not have an engineer on staff and most questions require a technical and elaborate answer, or relates to information that Hearst Power doesn't currently have, therefore AESI's assistance is required to answer these questions. Since some assets are owned by Hydro One and some policies mentioned are more relevant for larger LDCs, answering these questions are laborious for Hearst Power.

4.0 -VECC-40

Reference: Exhibit 4, Table 22, Pages 64

a) Please revise Table 22 to show the actual one-time application costs incurred to date.
b) Please explain what the $18,400 in "*Operating expenses associated with staff resources allocated to regulatory matters*" refers to and where in Appendix 2-JC (OM&A by programs) this amount can be found in 2021 and where the equivalent cost was shown in 2020.

Hearst Power:

a) Please see below table to show actual one-time application costs incurred to date (prior to interrogatories, based on invoice received):

Description		**Pre-interrogatories actuals ***
AESI engineering costs	$	21,410.00
Legal Fees	$	5,000.00
Accounting Fees	$	2,250.00
External Costs	$	-
External Costs	$	-
External Costs	$	-
Production & Submission	$	-
Public Notice	$	547.20
Interrogatories (Accounting/Legal)	$	-
Settlement/Oral hearing	$	-
Reply submission	$	-
Intervenor costs	$	-
Rate Order	$	-
Total Cost of Service Filing costs	$	29,207.20
* base on invoiced services to date only		

b) The $18,400 is the 1/5 of the cost expense budgeted for regulatory expense for the COS application:

AESI	$	36,000.00
Legal Fees	$	15,000.00
Accounting Fees	$	15,000.00
External Costs	$	-
External Costs	$	-
External Costs	$	-
Production & Submission	$	500.00
Public Notice	$	500.00
Interrogatories (Accounting/Legal)	$	-
Settlement/Oral hearing	$	-
Reply submission	$	-
Intervenor costs	$	25,000.00
Rate Order	$	-
Total Cost of Service Filing costs	***$***	***92,000.00***
Cost of service 1/5 per year	**$**	**18,400.00**

The cost was originally split 5-year from 2020 to 2024 in the initial application but has been revised for 2021 to 2025 in the update 2020 unaudited actuals included in these interrogatory responses (ie: there was no allocation in 2020 for 1/5 of the COS).

4.0 -VECC-41

Reference: Exhibit 4, Page 83

a) Are any of the property tax amounts listed in Table 31 related to the offices the Utility leases from the Town?

Hearst Power:

a) No property taxes are paid on the offices Hearst Power leases from the Town. No electricity, water and sewer, heating, insurance or maintenance fees are charge over and above the agreed office rental rates, as defined in the inter-corporate agreement.

Exhibit 5 – Cost of Capital

5-Staff-1

Ref: Exhibit 5, Page 18
Exhibit 5 / Appendix A
***Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084)*, December 11, 2009**

Hearst Power has filed a copy of the Promissory Note dated September 16, 2015 and due to the Corporation of the Town of Hearst, which is also the municipal shareholder of Hearst Power, in Appendix A to Exhibit 5. As OEB staff understands Hearst Power's evidence, this Promissory Note replaces the June 1, 2001 Promissory Note executed pursuant to Hearst Power's incorporation as part of electricity restructuring two decades ago. A copy of the June 1, 2001 Promissory Note is also filed in Appendix A.

The September 16, 2015 Promissory Note states that interest will be calculated as:

> … the lesser of (i) Prime Rate of the Bank of Canada plus five point five percent (Prime + 5.5%) per annum, calculated monthly, on the unpaid portion from time to time of the principal; and (ii) the undersigned's Net Income for such calendar year or part thereof. For the purposes of the promissory note, "Net Income" means, for any particular period, the amount which would, in accordance with generally accepted accounting principles, be classified on the consolidated income statement of the undersigned for such period as the net income of the undersigned.

OEB staff has prepared a table showing interest on long-term debt and net income from 2015 to 2019, shown below:

Year	Interest Expense ($)	Net Income ($)
2015	79,300	-173,629
2016	77,100	60,568
2017	83,162	49,549
2018	92,862	116,590
2019	84,263	186,546

OEB staff notes that Hearst Power has proposed that the municipal debt will attract the deemed long-term debt rate of 2.85%, as announced by the OEB in its November 9, 2020 letter on cost of capital parameters for 2021 rate applications.

In the *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (EB, 2009-0084)* (the Cost of Capital Report), the OEB states the following:[3]

[3] *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084)*, December 11, 2009, p. 53

The deemed long-term debt rate will act as a proxy or ceiling for what would be considered to be a market-based rate by the Board in certain circumstances. These circumstances include:

- For affiliate debt (i.e., debt held by an affiliated party as defined by the Ontario Business Corporations Act, 1990) with a fixed rate, the deemed long-term debt rate at the time of issuance will be used as a ceiling on the rate allowed for that debt.
- For debt that has a variable rate, the deemed long-term debt rate will be a ceiling on the rate allowed for that debt. This applies whether the debt holder is an affiliate or a third-party. **[Emphasis in original]**

a) OEB staff notes that the Bank of Canada does not publish a Prime Rate. The key interest rate of the Bank of Canada is "policy interest rate", also referred to as the target for the overnight rate. The major Canadian banks calculate their own Prime Rates, which are based on the Bank of Canada's overnight rate. The major banks generally move their Prime Rates in step with movements in the overnight rate by the Bank of Canada, and the Prime Rates of the banks are also generally equal to each other.[4] The Prime Rate of each bank is used as a basis for establishing fixed and variable rates for mortgages and other loans to customers. Please clarify exactly what rate is referred to in the Promissory Note as the "Prime Rate of the Bank of Canada".
b) Please provide some further background on the basis for using Prime Rate + 5.5% (Prime + 550 basis points) for calculating interest on the Promissory Note.
c) Please confirm or correct the table above of interest expense and net income.
d) Please confirm whether net income, for the purposes of calculating the interest payable annually on the Promissory Note is calculated on a financial or on a regulated basis.
e) Please explain how the long-term debt payments in 2015, 2016 and 2017 were calculated and determined.
f) Please indicate which parties must authorize the amount of long-term debt repayments in any given year.
g) Please provide an explanation for overpayments as shown in the above table.
h) Please confirm that Hearst Power's proposal that the promissory note debt due to the Town of Hearst attracts the OEB's deemed long-term interest rate is because the promissory note is affiliated and has a variable interest rate, per the OEB's policy on page 53 of the Cost of Capital Report. In the alternative, please explain the basis for Hearst Power's proposal.

Hearst Power:

[4] https://www.ratehub.ca/prime-rate

a) The “Prime Rate of the Bank of Canada” is actually the “Bank rate” under “Monetary Policy and LVTS Statistics”:

ABOUT THE BANK | CORE FUNCTIONS | MARKETS | BANK NOTES | PUBLICATIONS | RESEARCH | PRESS | STATISTICS

Quick Date:

Latest 1 day for daily series.

Latest 1 week for weekly series.

Latest 1 month for monthly series.

Search Criteria

Monetary Policy and LVTS Statistics		Daily	Weekly	Monthly
Target for the overnight rate		V39079 ☐		
Overnight money market financing rate [1]		V39050 ☐		
Bank rate		V39078 ☐	V80691310 ☐	V122530 ☑
Canadian Overnight Repo Rate Average (CORRA) (%)		☐		
Operating band	Low	V39076 ☐		
	High	V39077 ☐		
Overnight Repos (OR)[2]		☐		
Overnight Reverse Repos (ORR)[2]		☐		
LVTS settlement balances	Target	☐		
	Actual	☐		

Other Bank of Canada Operations	Daily	Weekly	Monthly
Term Purchase and Resale agreements	☐		

b) Prior to the 2015 COS application, Hearst Power had a balance remaining of $1,700,000 on the Promissory Note with an interest rate of 12% (A $100,000 payment was done in 2008 on the original note of 2001). Hearst Power negotiated with the Corporation of the Town of Hearst for a better rate and after a while, an agreement was reached to nearly cut in half the previous interest rate. Hearst Power ended up making an immediate reimbursement of $450,000 towards the principle on this debt and a new Promisssory Note was issued for the amount of $1,250,000.

c) Hearst Power confirms that the numbers in the table above showing interest on long-term debt and net income from 2015 to 2019 are correct except for a very small difference in the interest in 2016 which shows $77,100 but is actually $77,097.

d) The payment of interest on the Promissory Note is calculated on a financial basis.

e) The interest for the year 2015, 2016 and 2017 was calculated as per the table below.

Interest Calculator on Town of Hearst Promissory Note

2015

Month	Starting balance	Bank of Canada Prime rate	Interest rate (5.5% + prime)	Interest	Ending balance
Jan	$1,250,000	1.00%	6.50%	$6,771	$1,256,771
Feb	$1,256,771	0.75%	6.25%	$6,546	$1,263,317
Mar	$1,263,317	0.75%	6.25%	$6,580	$1,269,896
Apr	$1,269,896	0.75%	6.25%	$6,614	$1,276,510
May	$1,276,510	0.75%	6.25%	$6,648	$1,283,159
Jun	$1,283,159	0.75%	6.25%	$6,683	$1,289,842
Jul	$1,289,842	0.75%	6.25%	$6,718	$1,296,560
Aug	$1,296,560	0.50%	6.00%	$6,483	$1,303,043
Sep	$1,303,043	0.50%	6.00%	$6,515	$1,309,558
Oct	$1,309,558	0.50%	6.00%	$6,548	$1,316,106
Nov	$1,316,106	0.50%	6.00%	$6,581	$1,322,686
Dec	$1,322,686	0.50%	6.00%	$6,613	$1,329,300
			Total	$79,300	

Interest Calculator on Town of Hearst Promissory Note

2016

Month	Starting balance	Bank of Canada Prime rate	Interest rate (5.5% + prime)	Interest	Ending balance
Jan	$1,250,000	0.50%	6.00%	$6,250	$1,256,250
Feb	$1,256,250	0.50%	6.00%	$6,281	$1,262,531
Mar	$1,262,531	0.50%	6.00%	$6,313	$1,268,844
Apr	$1,268,844	0.50%	6.00%	$6,344	$1,275,188
May	$1,275,188	0.50%	6.00%	$6,376	$1,281,564
Jun	$1,281,564	0.50%	6.00%	$6,408	$1,287,972
Jul	$1,287,972	0.50%	6.00%	$6,440	$1,294,412
Aug	$1,294,412	0.50%	6.00%	$6,472	$1,300,884
Sep	$1,300,884	0.50%	6.00%	$6,504	$1,307,388
Oct	$1,307,388	0.50%	6.00%	$6,537	$1,313,925
Nov	$1,313,925	0.50%	6.00%	$6,570	$1,320,495
Dec	$1,320,495	0.50%	6.00%	$6,602	$1,327,097
			Total	$77,097	

Interest Calculator on Town of Hearst Promissory Note					
2017					
Month	**Starting balance**	**Bank of Canada - Prime Bank rate**	**Interest rate (5.5% + prime)**	**Interest**	**Ending balance**
Jan	$1,250,000	0.75%	6.25%	$6,510	$1,256,510
Feb	$1,256,510	0.75%	6.25%	$6,544	$1,263,055
Mar	$1,263,055	0.75%	6.25%	$6,578	$1,269,633
Apr	$1,269,633	0.75%	6.25%	$6,613	$1,276,246
May	$1,276,246	0.75%	6.25%	$6,647	$1,282,893
Jun	$1,282,893	0.75%	6.25%	$6,682	$1,289,575
Jul	$1,289,575	1.00%	6.50%	$6,985	$1,296,560
Aug	$1,296,560	1.00%	6.50%	$7,023	$1,303,583
Sep	$1,303,583	1.25%	6.75%	$7,333	$1,310,916
Oct	$1,310,916	1.25%	6.75%	$7,374	$1,318,289
Nov	$1,318,289	1.25%	6.75%	$7,415	$1,325,705
Dec	$1,325,705	1.25%	6.75%	$7,457	$1,333,162
			Total	$83,162	

f) The interest is presented to and approved by the Hearst Power Board of Directors at year end.

g) Hearst Power assumes that by the statement made in g) above regarding “overpayment” is when comparing the OEB deemed Long Term debt to the actual long-term debt paid out in the Promissory Note interest to the Shareholder. Hearst Power would like to note that in 2014, when the Promissory Note was negotiated, the OEB deemed long term debt rate was 5.57% which is not far from the 6 - 6.5% paid in its first year of the new Promissory note. Hearst Power has no control over bank or OEB deemed interest rates and Hearst Power’s management is aware that if the rate negotiated as part of the Promissory Note is higher than the OEB deemed LT rate (defined as “overpayment”), the LDC’s ROE calculation is affected.

h) Hearst Power is proposing to continue on the same path as previous years, where Hearst Power is using the OEB set long term debt rate to calculate the allowable portion of the interest expense under distribution rates and whatever amount is paid over this threshold, the “overpayment”, is added as interest adjustment for deemed debt, therefore affecting Hearst Power’s Return On Equity.

Note that in its preparation for the upcoming 2021 Cost of Service application, Hearst Power made a formal request to its Shareholder asking to renegotiate the Promissory Note based on the OEB's long-term debt rate of 3.21% as set out in the OEB's October 2019 Cost of Capital Parameter Updates for 2020 Cost of Service Applications and the request is currently under review.

5-Staff-2

Ref: Exhibit 5, Page 9

OEB staff notes that, in its application, Hearst Power documented a loan of $262,000 from the RBC Bank for the purpose of purchasing a new bucket truck. The forecast is that the loan would be in place on January 1, 2021, and attract an interest rate of 2.85%, with the loan having a term of 5 years.

OEB staff notes that the OEB's deemed long-term debt rate of 2021 is 2.85%, and this is would pertain to a long-term loan with a 30-year term. In general, loans of shorter terms would attract a lower rate, all else being equal, due to the lower risk that the lender is exposed to over the shorter term.

a) Please confirm when the loan was executed.
b) If executed, please document the actual loan term and rate of the executed loan.
c) If the loan has not been executed, please provide an update of the forecasted effective date, term and interest rate expected for this loan.
d) Please update Appendices 2-OA, 2-OB and the RRWF, for the 2021 test year, for any changes made in response to this interrogatory.

Hearst Power:

a) Due to COVID-19 delays and the Provincial emergency shut down in early 2021, the new bucket truck has not yet been delivered as of March 11, 2021. The loan will be disbursed as soon as the bucket truck is picked up, which Hearst Power is expecting end of March, early April.

b) It is already agreed with RBC Bank that the term will be 5 year and the rate set at 2.85%.

c) Please refer to a) and b)

d) No change is required.

5-Staff-3

Notional Debt

Ref: Exhibit 5, Pages 14-15
***Filing Requirements For Electricity Distribution Rate Applications, 2020 Edition for 2021 Rate Applications, Chapter 2, Cost of Service*, May 14, 2020, Pages 44-45**

On page 14 of Exhibit 5, Hearst Power states:

Hearst Power's deemed debt for 2021 is $1,448,907 as provided in Table 5, and the actual debt, per Table 6, is projected to be $1,062,000. Accordingly, Hearst Power has positive notional debt of $386,914. In this application, as directed in the Chapter 2 Filing Requirements for Electricity Distribution Rate Application, the notional debt attracts the weighted actual cost of long-term debt of 2.90%.

Pages 44-45 of the current Chapter 2 Filing Requirements documents the following:

> Notional debt is that portion of the deemed debt capitalization that results from differences between the distributor's actual debt and the deemed debt thickness of 60% (56% long-term debt and 4% short-term debt). Notional debt can arise for a number of reasons such as the difference between actual capital assets and regulatory rate base due to the addition of the formulaic working capital allowance.
>
> Divergence from the deemed capital structure is generally under the control of the utility as it may relate to timing for debt financing for planned capital investments, as well as the interests of shareholders, with regards to dividend policy (paying out earnings) versus reinvesting retained earnings.
>
> Notional debt can be either positive (i.e. deemed debt is greater than actual debt) or negative (where deemed debt is less than actual debt). *Since the factors which cause notional debt to arise are largely under the control of the utility, notional debt should attract the weighted average cost of actual long-term debt rather than the current deemed long-term debt rate issued by the OEB.* This approach has been upheld in several decisions in recent years.[29]
>
> The possible exception to this is that the deemed long-term debt rate should apply as a ceiling in a situation where a utility is 100% equity financed and has no current debt or recent history of debt financing (and thus no current or historical information on actual debt costs for the utility). ***[Emphasis Added]***
>
> 29 December 19, 2014 (Updated August 11, 2016) Hydro One Remote Communities Decision with Reasons, EB-2008-0232, page 12, London Hydro Inc. Decision with Reasons, EB-2008-0235, pages 36-37.

a) Please explain the calculations shown in the three tables of pages 14 and 15 of Exhibit 5, including the sources for the data. As one example, what is the source for the 2.90% long-term debt rate shown on the table on the top of page 15. If possible, please provide these tables in working Microsoft Excel format, showing the formulae used.

b) Please explain how Hearst Power's proposed treatment of "notional" debt is consistent with the policy as summarized in the Chapter 2 Filing Requirements and originally articulated in Cost of Capital Report.

Hearst Power:

a) The excel version of the calculations are filed along with these responses.

b) OEB Staff Report EB-2009-0084 Review of the Cost of Capital for Ontario's Regulated Utilities

The report states the following. HPDC believes that it has followed board guidance on calculating Notional Debt. If the OEB has a specific calculation they expect utilities to use, they should include them in Chapter 2 Appendices along with explanations how what is expected.

Notional debt can arise for a number of reasons such as the difference between actual capital assets and regulatory rate base due to the addition of an allowance for working capital.

Divergence from the deemed capital structure is generally under the control of the utility as it may relate to timing for debt financing for planned capital investments, as well as the interests of shareholders, such as reinvesting retained earnings.

Notional debt can be either positive (i.e. deemed debt is greater than actual debt) or negative (where deemed debt is less than actual debt). Since the factors which cause notional debt to arise are largely under the control of the utility, the OEB has determined in a number of cases that notional debt should attract the weighted average cost of actual long-term debt rate rather than the deemed long-term debt rate issued by the OEB.[4] An exception to this is where a utility is 100% equity financed and has no current debt or recent history of debt financing. In such a circumstance, the OEB has noted that the deemed long-term debt rate should apply as a ceiling.

5.0-VECC-42

Reference: Exhibit 5, page 13

a) Please confirm that the RBC truck loan is at the same rate as the Board's default affiliated debt rate of 2.85%.

Hearst Power:

a) Hearst Power confirms the RBC Bank truck loan has an interest rate of 2.85%.

5.0-VECC-43

Reference: Exhibit 5, page 17-

a) Please confirm that the actual payment made to the Town of Hearst for the affiliated debt is $47,307 based on a rate of 5.913% (prime + 5.5%).

b) The revised promissory note (September 2015) notes an amount of $1.25 million. The prior years show a reduction in principle. Please describe the repayment schedule for this loan.

Hearst Power:

a) The actual payment made to the Town of Hearst for the affiliated debt is $56,620; please refer to table below for details:

Interest Calculator on Town of Hearst Promissory Note

2020

Month	Starting balance	Bank of Canada - Prime Bank rate	Interest rate (5.5% + prime)	Interest	Ending balance
Jan	$1,000,000	2.00%	7.50%	$6,250	$1,006,250
Feb	$1,006,250	2.00%	7.50%	$6,289	$1,012,539
Mar	$1,012,539	1.00%	6.50%	$5,485	$1,018,024
Apr	$1,018,024	0.50%	6.00%	$5,090	$1,023,114
May	$823,114	0.50%	6.00%	$4,116	$827,229
Jun	$827,229	0.50%	6.00%	$4,136	$831,365
Jul	$831,365	0.50%	6.00%	$4,157	$835,522
Aug	$835,522	0.50%	6.00%	$4,178	$839,700
Sep	$839,700	0.50%	6.00%	$4,198	$843,898
Oct	$843,898	0.50%	6.00%	$4,219	$848,118
Nov	$848,118	0.50%	6.00%	$4,241	$852,359
Dec	$852,359	0.50%	6.00%	$4,262	$856,620
			Total	$56,620	
Payment of $200,000 in May					

b) Hearst Power had an affiliated debt with its Shareholder since the year 2001 where the Promissory Note was in the amount of $1.8M. In 2015, the amount left to pay was $1.25M and here is the repayment schedule since:

Year	Capital repayment	Year end balance	
2015	$ -	$ 1,250,000.00	
2016	$ -	$ 1,250,000.00	
2017	$ -	$ 1,250,000.00	
2018	$ -	$ 1,250,000.00	
2019	$ 250,000.00	$ 1,000,000.00	
2020	$ 200,000.00	$ 800,000.00	
2021	*$ 100,000.00*	*$ 700,000.00*	*Forecast*

Exhibit 7 – Cost Allocation

7-Staff-1

Contributed Capital
Ref: Cost Allocation Model, sheet I4 BO Assets
All $124,995 of contributed capital is identified as being applicable to account 1860 – Meters.

a) Please provide details on Hearst Power's process for determining which assets are evaluated for capital contributions, and how any resulting capital contributions are attributed to those assets.

Hearst Power:

a) 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).

Contributed capital contribution occur in results of damages by third parties to the system, for example, a Loader may hit and break a pole during snow removal or a transport truck may hit an overhead wire if it's load is over the height limit set by the Ministry. Also, contributed capital can occur when new or current customers request the existing distribution line to be extended in order to connect their building/dwelling. The attribution of contributed capital is based on those asset, exactly as any other LDC capital asset is allocated.

7-Staff-2

Transformer Ownership Allowance
Ref: Cost Allocation Model, sheet I6.1 Revenue; sheet I6.2 Customer Data; sheet I8 Demand Data
Hearst Power has indicated that 67,244 kW is eligible for transformer ownership allowance from a total of 65,174 kW of billing demand in the General Service (GS) > 50 kW rate class. In the Intermediate rate class, it indicates that 60,194 kW of demand is eligible for transformer ownership allowance from a total of 57,468 kW of demand.

Sheet I6.2 Customer Data indicates that every customer in every rate class uses primary distribution, line transformation, and secondary distribution from Hearst Power. Similarly, sheet I8 Demand Data indicates that every rate class depends on primary distribution, line transformation, and secondary distribution for every kW delivered.

a) Please explain how more than 100% of the billing demand in the GS > 50 and intermediate classes are eligible for transformer ownership allowance, and at the same time, all of the customers and demand are reliant on Hearst Power for line transformation and secondary distribution.

b) What proportion of the billing demand in each of the GS > 50 and Intermediate rate classes is eligible for transformer ownership allowance?
c) Does Hearst power have any multi-unit residential or GS < 50 kW served at primary voltage?
d) Please make revisions to the cost allocation model as required.

Hearst Power:

a) 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.

b) 100% of customers in the GS>50 and Intermediate classes are eligible for transformer allowance.

c) HPDC does not have such service

d) The model filed along with these responses has been updated accordingly.

7-Staff-3

Customer Connections
Ref: Load Forecast Model, sheet Final LF
Ref: Cost Allocation Model, sheet I6.2 Customer Data
Ref: Revenue Requirement Work Form (RRWF), sheet 10. Load Forecast

The load forecast indicates that there are expected to be 478 customers in the GS < 50 rate class, but the cost allocation model and RRWF indicate 470 customers. In the GS > 50 rate class, the load forecast indicates 35 customers, but cost allocation model and RRWF indicate 36 customers. In the Street Lighting rate class, the load forecast indicates 973 customers, but cost allocation model and RRWF indicate 967 customers. The number of street lighting devices has not been populated in the cost allocation model.

a) Please confirm whether the load forecast reflects the number of devices (street lights), or the number of connections made to the distribution system.
b) On average, how many street lights share one connection to the distribution system?
c) Please explain why the customer counts in the load forecast do not match the cost allocation model and revenue requirement work form.
d) Please correct any models as required.

Hearst Power:

a) All models have been updated to reflect the correct customer count from the Load forecast

b) Each streetlight has its own connection to the distribution system. Each connection is fused.

c) See a)

d) See a)

7-Staff-4

Weighting Factors
Ref: Exhibit 7, Page 8
Ref: Cost Allocation model, sheet I6.2 Customer Data

Hearst Power calculated a weighting factor labelled “Cost Per Connection”. Billing and Collecting weighting factors are used to calculated weighted bills on sheet I6.2 Customer Data, row 30. I.e. it is the relative cost per bill, not the relative cost per connection that is pertinent.

Hearst Power has used a services weighting factor of 1.0 for Residential, 2.0 for all General Service rate classes, and 0 for street light and sentinel light.

a) Did Hearst Power calculate the billing and collecting weighting factor on a per connection, a per customer, or per bill basis?
b) If Hearst Power calculated the billing and collecting weighting factor on a per connection basis please explain why it believes this is appropriate, or revise to calculate on a per-bill basis.
c) Please confirm that street lighting and sentinel lighting customers are responsible for providing their own service connections to the secondary distribution system, or explain why a weighting factor of zero is appropriate.
d) Please provide a derivation of the services weighting factors.

Hearst Power:

a) HPDC calculated the billing factors based on a connection basis

b) The number of bills is simply the number of customers multiplied by 12. With the exception of Streetlights where the billing and collecting factor was missed, the weighting factor is identical to the connection.

c) HPDC confirms that street lighting and sentinel light customers are responsible for providing their own service connections.

d) HPDC used the same service weighting factors as its 2015 cost of service.

7-Staff-5

Meter Capital, Meter Reading
Ref: Cost Allocation model, sheet I7.1 Meter Capital; sheet I7.2 Meter Reading
In the meter capital worksheet, Hearst Power has entered meters reflecting one meter per customer in each of the Residential and GS < 50 kW rate classes, and no meters for any other rate class.

In the meter reading worksheet, Hearst Power has entered reads reflecting one read per customer in each of the Residential, GS < 50 kW, and GS > 50 kW rate classes, and not for the Intermediate rate class.

a) Please explain the circumstances regarding meter ownership in the GS > 50 kW and Intermediate rate classes that give rise to no meters being recorded for these rate classes in I7.1 Meter Capital, or make revisions as appropriate.
b) Please explain why no meter reading costs are identified for the Intermediate rate class, or make revisions as appropriate.

Hearst Power:
a) & b) The model has been updated to reflect meter and capital costs.

7-Staff-6

Revenue to Cost Ratios
Ref: Exhibit 7, Page 21.
Hearst Power proposes to bring its sentinel and street lighting classes back to the lower and upper boundaries of the ranges. To do this, it proposes to make an offsetting increase the residential revenue-to-cost ratio from 96.96% to 98.42%. The revenue-to-cost ratio for Intermediate is at 81.36%.

a) Please explain how Hearst Power selected the residential rate class to make the offsetting adjustment.

Hearst Power:
a) HPDC used its largest class to absorb the shortfall created by moving the classes outside of the range within the range.

7.0 – VECC–44

Reference: Exhibit 3, page 40
Exhibit 7, page 11
2021 Cost Allocation Model (CAM), Tabs 6.2, 7.1 and 7.2

a) It is noted that the customer/connection counts for the GS<50, Intermediate and Streetlight classes used on the Cost Allocation model (Tabs 6.2, 7.1 and 7.2) do not match those in the Load Forecast. See table below:

	GS<50	GS>50	Intermediate	StreetLight
Load Forecast	478	35	2	973
Tab 6.2	470	36	2	967
Tab 7.1	470	0	0	N/A
Tab 7.2	470	36	0	N/A

Please explain the differences or revise the Cost Allocation Model as required.

Hearst Power:

a) The initial application was subject to an input error where cells were inadvertently linked to 2020 customer count instead of 2021. All models have been updated to reflect the customer count of the load forecast.

7.0 – VECC–45

Reference: Exhibit 7, page 13
Exhibit 8, page 5
2021 Cost Allocation Model, Tab I6.1

a) Please explain why, for both the GS>50 and Intermediate classes, the kW receiving the transformer ownership allowance exceed the class' total billing demand.

Hearst Power:

a) The model has been updated to reflect up to date information.

7.0 – VECC–46

Reference: Exhibit 7, page 8
Preamble: At page 8 the Application sets out the calculation for the Billing and Collecting weighting factors.

a) Please explain why the total annual cost for each account in Table 3 does not equal the 2021 cost for that account as set out in Tab I3 (TB Data) of the Cost Allocation Model.
b) Please explain why the cost for Meter Reading (Account 5310) is included in the derivation of the weighting factors for Billing and Collecting. Doesn't Meter Reading Expense have a different allocation factor?
c) For each of the rows in Table 3 please explain how the total expense was allocated as between the customer classes.

d) Please explain why the 2021 customer counts used in Table 3 for the Residential and GS<50 classes don't match those in Exhibit 3.

e) Please explain why the number bills used in Table 3 for the Street Lighting and Sentinel classes do not equal 12 times the number of customers of these classes as set out in Tab I6.2 of the Cost Allocation Model.

f) Please explain how the values in each of following rows in Table 3 were determined: i) 5315 - Customer Billing, ii) Total and iii) Cost per Connection.

Hearst Power:

a) The customer count was erroneous and has been rectified in all models supporting these responses.

b) Billing and collecting is not possible without meter reading therefore it's HPDC's opinion that meter reading costs should be included in billing and collecting. Furthermore, HPDC notes that the account falls under the OEB heading of billing and collecting.

c) The expense is allocated based on a weighting of the number of bills per class in comparison to the overall number of bills.

	A	B	C	D	E	F	G	H	I	J	K
1	**2019**										
2	**Accounts 5305 - 5340**	2019									
3	5305-Supervision	$0									
4	5310-Meter Reading Expense	$16,649									
5	5315-Customer Billing	$206,542									
6	5320-Collecting	$44,427									
7	5325-Collecting- Cash Over and Short	$0									
8	5330-Collection Charges	$711									
9	5340-Miscellaneous Customer Accounts Expenses	$23,361									
10											
11											
12		**Residential**	**GS < 50 ***	**GS > 50**	**Intermediate**	**Street Lighting**	**Sentinel Lighting**	**Total Annual Cost**		**Acct**	
13	2021 Projected # of Customer/Connections (load forecast)	2258	456	35	2	973	12	**3736**			
14	# bills	27096	5472	420	24	24	108	**33144**			
15											
16	*5310 - Meter Reading - Labor*		217.38	16.68				*1,316.66*		*5310*	Should total $16,649
17	*5310 - Meter Reading expenses (ERTH Holdings & Metersense*	=$H$17*B14/$H$14	2,531.32	194.29	11.10	11.10	49.96	*15,332.22*		*5310*	
18	*5315 - Customer Billing - Labor & overheads*	85,971.98	17,361.92	1,332.60	76.15	76.15	342.67	*105,161.47*		*5315*	
19	*5315 - Customer Billing expenses (ERTH Holdings, Canada Pos*	67,882.64	13,708.81	1,052.21	60.13	60.13	270.57	*83,034.48*		*5315*	Should total $206,542
20	*5315 - Customer Billing expenses (Utilismart - Meter reads)*			1,672.80	1,672.80			*3,345.60*		*5315*	
21	*5315 - Customer Billing expenses (Utilismart - Settlements)*	12,262.85	2,476.47	190.08	10.86	10.86	48.88	*15,000.00*		*5315*	
22	*5320 - Collecting - Labour*	2,855.75	576.71	44.27	2.53	2.53	11.38	*3,493.17*		*5320*	Should total $44,427
23	*5320 - Collecting - Services provided by other parties*	33,464.54	6,758.12	518.72	29.64	29.64	133.38	*40,934.04*		*5320*	
24	*5330 - Credit bureau collection fees*	581.19	117.37	9.01				710.91		5330	
25	*5340 - Misc. Cust Account Exp. - Communication services (24 h*	33,464.54	6,758.12	518.72	29.64	29.64	133.38	23,360.62		*5340*	Should total $23,361
26											
27	5315 - Customer Billing	249,017.94	50,506.21	5,549.37	1,892.85	220.05	990.23	291,689.17			
28											
29	Total	110.28	110.76	158.55	946.43	0.23	82.52				
30											
31	Cost Per Connection	1.00	1.00	1.44	8.58	0.00	0.75				
32											
33	Weighting (Residential set as standard)										

d) See response to a) above

e) This error was corrected in the model filed with these responses.

f) Please see c) above. The excel version is filed along with the response.

7.0 – VECC–47

Reference: Exhibit 7, pages 11-13

a) Please explain why the Primary Customer, Secondary Customer and Line Transformer customer counts (per page 12) for the GS>50 and Intermediate classes are all the same value when some of kW in each of these classes (per page 13) receive the transformer ownership allowance.
b) Please explain why the Primary Customer, Secondary Customer and Line Transformer 4NCP (per page 11) for the GS>50 and Intermediate classes are all the same value when some kW in each of these classes (per page 13) receive the transformer ownership allowance.

Hearst Power:

a) Please see below a screenshot of HPDC's 2015 CA model (I4 BO Assets) as per the settlement agreement

1825-2	Storage Battery Equipment <50 kV		100.00%	$0
1830	Poles, Towers and Fixtures	$742,005		($742,005)
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery		40.00%	$296,802
1830-4	Poles, Towers and Fixtures - Primary		35.00%	$259,702
1830-5	Poles, Towers and Fixtures - Secondary		25.00%	$185,501
1835	Overhead Conductors and Devices	$991,653		($991,653)
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery		40.00%	$396,661
1835-4	Overhead Conductors and Devices - Primary		35.00%	$347,079
1835-5	Overhead Conductors and Devices - Secondary		25.00%	$247,913
1840	Underground Conduit	$7,681		($7,681)
1840-3	Underground Conduit - Bulk Delivery		11.00%	$845
1840-4	Underground Conduit - Primary		39.00%	$2,996
1840-5	Underground Conduit - Secondary		50.00%	$3,841
1845	Underground Conductors and Devices	$440,897		($440,897)
1845-3	Underground Conductors and Devices - Bulk Delivery		11.00%	$48,499
1845-4	Underground Conductors and Devices - Primary		39.00%	$171,950
1845-5	Underground Conductors and Devices - Secondary		50.00%	$220,448
1850	Line Transformers	$574,806		$0
1855	Services	$30,916		$0
1860	Meters	$761,149		$0
	Total	**$3,549,106**		**($0)**
	SUB TOTAL from I3	**$3,549,106**		

b) Please see below a screenshot of HPDC's 2021 CA model (I4 BO Assets) as proposed. The allocation per primary and secondary is the same in both applications.

1830	Poles, Towers and Fixtures	$805,825		($805,825)
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery		40.00%	$322,330
1830-4	Poles, Towers and Fixtures - Primary		35.00%	$282,039
1830-5	Poles, Towers and Fixtures - Secondary		25.00%	$201,456
1835	Overhead Conductors and Devices	$272,532		($272,532)
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery		40.00%	$109,013
1835-4	Overhead Conductors and Devices - Primary		35.00%	$95,386
1835-5	Overhead Conductors and Devices - Secondary		25.00%	$68,133
1840	Underground Conduit	$5,377		($5,377)
1840-3	Underground Conduit - Bulk Delivery		11.00%	$591
1840-4	Underground Conduit - Primary		39.00%	$2,097
1840-5	Underground Conduit -		50.00%	$2,689
1845	Underground Conductors and Devices	$55,464		($55,464)
1845-3	Underground Conductors and Devices - Bulk Delivery		11.00%	$6,101
1845-4	Underground Conductors and Devices - Primary		39.00%	$21,631
1845-5	Underground Conductors and Devices - Secondary		50.00%	$27,732
1850	Line Transformers	$218,995		$0
1855	Services	$54,011		$0
1860	Meters	$724,921		$0
	Total	**$2,141,357**		**$0**
	SUB TOTAL from I3	**$2,141,357**		

7.0 – VECC–48

Reference: Exhibit 7, page 6
2021 Cost Allocation Model, Tab I4 - BO Assets
EB-2014-0080, CA Model per IR Responses

a) In the EB-2014-0080 Application, the Cost Allocation Model filed with the IR responses classified all assets in Accounts 1830, 1835, 1840 and 1845 as secondary. However, in the current application portions of the assets in these accounts are classified as bulk and primary. Please explain the reasons for the change and, in particular, the basis for classifying some of the assets in these accounts as bulk assets.

Hearst Power:
a)

7.0 – VECC–49

Reference: Exhibit 7, page 18

a) Pease explain why Hearst is proposing to increase the Residential R/C ratio which has status quo value of 96.96% but it not proposing to increase the R/C ratio for the Intermediate class when the status quo ratio there is only 81.36%.

Hearst Power:

a) HPDC chose its largest class to absorb the shortfall of approximately 14K over a revenue requirement allocation of 800K.

Exhibit 8 – Rate Design

8-Staff-1

Retail Transmission Service Rates (RTSRs)
Ref: Exhibit 8, Pages 10-11
Ref: EB-2020-0030, Decision and Rate Order, December 17, 2020
Ref: EB-2020-0251, Decision and Rate Order, December 17, 2020

Since Hearst Power filed its application, the OEB has approved updated sub-transmission rates for Hydro One Networks Inc and the Uniform Transmission Rates (UTRs).

a) Please update the RTSR model to reflect the Hydro One Sub-Transmission rates and the UTRs issued on December 17, 2020.

Hearst Power:

a) The revised RTSR model is filed along with these responses.

8-Staff-2

Loss Factors
Ref: Exhibit 8, Page 25

Hearst Power states that it makes a point of conducting a line loss study prior to every Cost of Service application. It also proposes to increase its loss factor from 1.0414 to 1.0538.

OEB staff notes that the losses in 2017 and 2019 are higher than in other years from the five-year average used to calculate the proposed loss factor.

a) Please provide reasons for the increase in the loss factor since the last Cost of Service proceeding.
b) Please provide the results of the line loss studies in 2017 and 2019, including any opportunities to improve losses.
c) Please provide any reasons for the higher losses in 2017 and 2019.

Hearst Power:

a) The loss factor is calculated based on best data available to Hearst Power. Since 2015, Hearst Power has been increasing it's use of technology (ie: billing system exports to Excel, added UtiliSmart reading points for microFITs and FIT generators) to better provide accurate statistical data for loss calculation and prevent manual data compilation errors. Also, Hearst Power is a distributor interconnected and surrounded by Hydro One and is consequently dependant on Hydro One to provide correct billing data for wholesale purchases. In recent years, Hydro One was subject to defective equipment (ie: blown phase, blown metering, etc) that required Hydro One to bill Hearst Power under an estimated kWh consumption. Hearst Power must use the data provided by Hydro One to report, whether they provide actuals or estimates.

b) HPDC did not conduct a line loss study as planned.

c) Appendix 2-R has been updated to reflect correction to wholesale and retail which rectify the issue.

8-Staff-3

Mitigation
Ref: Exhibit 8, Page 33
Ref: RRWF, Tab 11. Cost Allocation

Hearst Power indicates that as a form of rate mitigation, it is considering "Incrementally moving the Cost-to-Revenue ratio to 100% over a number of years, with the Test Year (2021) being at 80% so as to comply with the minimum Board floor parameter for this rate class."

The RRWF shows a revenue-to-cost ratio of 79.91% for 2021-2023 for the Sentinel class.

a) Which revenue-to-cost ratio is proposed for 2021?
b) Has Hearst Power considered a multi-year transition to a final revenue-to-cost ratio of 80% as a form of mitigation?

Hearst Power:

a) 79.91 rounds up to 0.80. HPDC is willing to explore rate mitigation including moving the intermediate and sentinel classes closer to 1.00 as part of the application process. However, for the purpose of the filing and interrogatory responses HPDC believes it is complying with board policy in that respect.

b) See response above.

8.0 –VECC-50

Reference: Exhibit 8, pages 5 and 28
2021 RRWF, Tabs 10 & 13

a) The customer/connection counts used in Exhibit 8 for the GS<50, GS>50, and Street Light classes do not match those from the Load Forecast per

Exhibit 3, page 40. Please reconcile and revise the proposed rates as required.

Hearst Power:

a) The customer count at page 40 of Exhibit 3 is in fact the correct data. Please note that the forecast has been updated to reflect actual 2020 consumption and customer count.

8.0 –VECC-51

Reference: Exhibit 8, pages 8-10

a) Please confirm that in Table 4 (page 8) the Minimum System with PLCC Adjustment values for Street Lights and Sentinel are reversed.
b) At page 10 the Application states that for the Sentinel class – "Since the calculated rates at current levels split fell outside the maximum boundary, HPDCL opted to keep the same fixed rates as current rates…… The resulting fixed rate is proposed to be $11.44."
    a. What would be the 2021 fixed monthly charge for the Sentinel class if the existing fixed-variable split was maintained?
    b. Please reconcile the statement that "HPDCL opted to keep the same fixed rates as current rates" with the fact the proposed rate is $11.44 while the current rate is $7.45.

Hearst Power:

a) HPDC confirms that the PLCC Adjustment was inadvertently reversed for the Street Lighting ($4.53) and Sentinel ($21.67)

b)
    a. The MFC would be of $7.95 while the variable charge would be $31.53
    b. The statement was incorrect. HPDC intended to adopt the proposed rate at current split rather than keep the existing rate.

8.0 –VECC– 52

Reference: Exhibit 8, pages 10-14
2021 RTSR Workform

a) With respect to the RTSR Workform, what year's RRR data was used for Tab 3 and what year's billing data was used for Tab 5?

b) Please update the RTSR Workform to include the approved 2021 Uniform Transmission Rates (EB-2020-0251) and Hydro One's approved 2021 distribution rates (EB-2020-0030).

Hearst Power:

a) The model is automatically populated via an OEB mechanism. The consumption cells are locked. Rates as approved in EB-2019-0040 were used as inputs.

b) The model filed along with these responses reflects the most up to date UTRs

8.0 –VECC-53

Reference: Exhibit 8, page 15

a) Please confirm that the 2021 Retail Services Charges need to be updated to reflect the Board's EB-2020-0285 Decision and Rate Order.

Hearst Power:

a) Hearst Power agrees.

8.0 –VECC-54

Reference: Exhibit 8, pages 25-26

a) With respect to Table 15 (Appendix 2-R), does row A(2) include distributed generation (e.g., FIT and microFIT) purchases by Hearst per Appendix 2-R's footnotes?
b) With respect to the calculation of the weighted average supply facility loss factor, please explain why the sum of the deliveries via HON and IESO (70,855,448 kWh) is less than the year's total retail sales (77,770,163 kWh)? Does the calculation need to also take into account purchase for distributed generation (e.g., FIT and microFIT)?

Hearst Power:

a) Yes, the wholesale kwh delivered to the distributor, row A(2), includes the total kwh electricity purchased with FIT and microFIT purchased kwh.

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

	2019			
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**

b) The 70,855,448 kWh is accounting for IESO and Hydro One. The table also account for 9,973,274 kWh from FIT generators and 606,999 from microFIT generators.

8.0 –VECC-55

Reference: Exhibit 8, page 33
2021 Tariff Schedule and Bill Impact Model

a) One of the options put forward by Hearst on page 33 for addressing the Sentinel class' 20.8% total bill impact is: "Incrementally moving the Cost-to-Revenue ratio to 100% over a number of years, with the Test Year (2021) being at 80% so as to comply with the minimum Board floor parameter for this rate class." Please explain how this approach would mitigate the bill impacts for 2021 when the current proposal is to set the R/C ratio for this class at 80% (79.91%) for 2021.

b) In the calculation of the bill impacts for the Sentinel class the service charge volume is set at "2". Please explain why.

Hearst Power:

a) HPDC could move from 0.67 to the floor of 0.80 in multiple years alleviating their bill impact for 2021 and possibly 2022. HPDC deems it important to point out that entire class is collecting a total of only $2550 over the period of 1 year. Bill impacts tend to appear greater when revenues as smaller.

c) HPDC has used the same inputs for bill impacts as it has for past applications. (2018,2019,2020)

Exhibit 9 – Deferral and Variance Accounts

9-Staff-1

Ref: Exhibit 9, Page 05
Hearst Power states that:

> Hearst Power proposes to dispose of a credit of $36,378 related to Group 1 and debit of $36,272 related to Group 2 Variance/Deferral Accounts. This credit includes carrying charges up to and including December 31, 2019.

a) Please confirm that the carrying charges included in the above-mentioned balances were calculated up to and including April 30, 2021, rather than December 31, 2019 as stated. If not, please explain.
b) At the above-noted reference, Hearst Power proposed Group 1 and 2 DVA balances to be disposed over two years. Please explain the rationale for disposing these balances over two years instead of one.

Hearst Power:

a) The carrying charges included were calculated up to April 30, 2021 based on the December 31, 2019 audited DVA values.

b) Hearst Power proposed 2 years to lessen the impact (increase) on residential rates.

9-Staff-2

Ref: Exhibit 9, Page 46
On Page 49 of Exhibit 9, there is mention of Table 18 containing the variances for accounts 1588 and 1589 when comparing the old (the way in which Hearst Power originally performed the settlement and true up process) vs the new method (the settlement and true up process using OEB's Accounting Guidance Related to commodity Pass-Through Accounts 1588 & 1589, February 21, 2019).

a) Please confirm the above reference is referring to table 8.

Hearst Power:

a) Hearst Power confirms.

9.0 –VECC-56

Reference: Exhibit 9, page 5 & Exhibit 1, page 69

a) The Exhibit 1 references states that "*Group 1 and Group 2 DVA balances are proposed to be disposed of over 1 years*." [sic]. At Exhibit 9, page 50 it states the proposed disposition is over 2 years. We note that the rate riders appear to be calculated on a 1-year basis. Please clarify which period Hearst is seeking to dispose of the accounts.

Hearst Power:

a) Hearst Power request to dispose of the Group 1 and Group 2 DVA balances over a 2-year period to lessen the impact on residential rates.

9.0 –VECC-57

Reference: Exhibit 9

a) Please provide the balance at year-end 2020 in Account 1509 – Impacts Arising from the COVID-19 Emergency, Sub-account Other Costs.
b) Please confirm that the application does not have any pandemic related costs and that these costs, to the extent that Hearst Power may seek recovery of them, are being booked in Account 1509.

Hearst Power:

a) As of December 31, 2020, Hearst Power had a balance of $7,191.01 in this account. Very minimal expenses, <$1,000, are expected to be booked in this account for 2021.

b) Except for a slightly higher bad dept expense than the average of previous years due to an inability to disconnect, Hearst Power confirms that it did not include any pandemic related costs. All COVID-19 related expenses are being booked in Account 1509 for disposition at a later date.

9.0 –VECC-58

Reference: Exhibit 9

As per the OEB's July 25, 2019 letter, the OEB expected distributors to record the impacts of CCA rule changes in Account 1592 - PILs and Tax Variances – CCA Changes for the period November 21, 2018 until the effective date of the distributor's next cost-based rate order.21 The OEB expected distributors to bring forward any amounts tracked in this account for review and disposition, *at a distributor's next cost-based rate application*. (OEB Filing Requirements, Chapter 3, May 14, 2020)

a) Please explain why no balances are shown for the changes to CCA rules in account 1592.

Hearst Power:

a) Article Bill C-97 ; accelerated Investment Incentive program offers an option to take an accelerated CCA rate for the corporation income taxes. At year end 2019, Hearst Power discussed this option with its accounting firm and the accelerated CCA rate would have generated a tax saving of $3,002 for HPDC. 50% of this amount would have been reclassified in a DVA account. Since the amount was not material, the accelerated rate wasn't used by the corporation. The taxpayers will benefit of the unused accelerated rates in the next fiscal years.