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

Digitally signed by Abdullah Navid
Date: 2021.02.22 14:13:01 -05'00'

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
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.

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.

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.

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

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).

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.
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.

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.

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.

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.

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).

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.

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.

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.

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.

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).

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.

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.

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?

2-Staff-11
Ref: Exhibit 2, Distribution System Plan, Page 22
Hearst Power states on page 22**:**

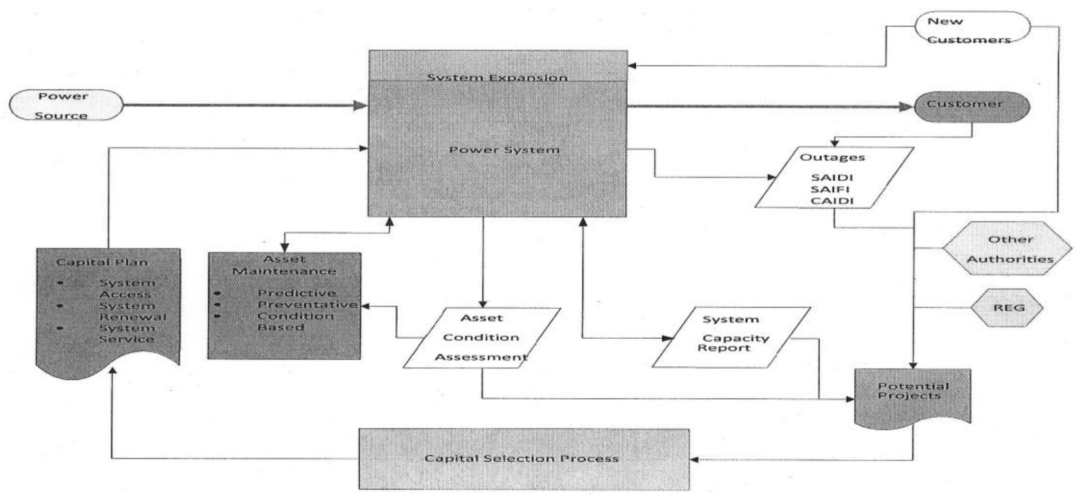
> Hearst Power's Corporate goals are:
> - To deliver electrical power to the customers that meet the customers requirements.
>   - Reliably

    - Affordably
- 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.:

[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”

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 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?

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.

[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

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?

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?

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?

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?

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.

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)?

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?

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?

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?

Exhibit 3 – Revenues

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.

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.

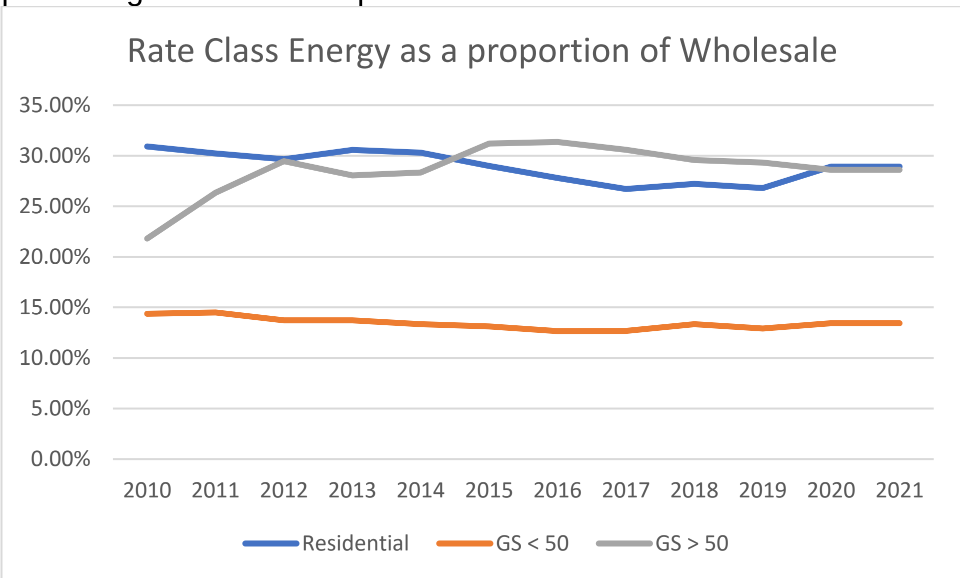
Energy use (MWh) by rate class vs Wholesale

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.

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.

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?

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.

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?

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.

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

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

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.

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?

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.

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.

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.

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.

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.

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).

LRAMVA
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.

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.

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.

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.

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?

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.

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.

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.

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.

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

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.

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.

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.

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.

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.

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.

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.

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.

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.

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.

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?

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.

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.