PUBLIC INTEREST ADVOCACY CENTRE
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November 2, 2020 **VIA E-MAIL**

Christine E. Long
Registrar (registrar@oeb.ca)
Ontario Energy Board
Toronto, ON

Dear Ms. Long:

Re: EB-2020-0026 - Halton Hills Hydro Inc. (HHHI) 2021 Cost of Service Rates
Interrogatories of the Vulnerable Energy Consumers Coalition (VECC)

Please find attached the interrogatories of VECC to the HVAC Coalition in the above-noted proceeding. We have also directed a copy of the same to the Applicant.

Yours truly,

M Garner

Mark Garner
Consultants for VECC/PIAC

Mark C Garner

Digitally signed by Mark C Garner
Date: 2020.11.02 17:04:41 -05'00'

Email copy:
David Smelsky, Chief Financial Officer, HHHI Chief Financial Officer
dsmelsky@haltonhillshydro.com

REQUESTOR NAME	**VECC**
TO:	**Halton Hills Hydro Inc. (HHHI)**
DATE:	**November 2, 2020**
CASE NO:	**EB-2020-0026**
APPLICATION NAME	**2021 Cost of Service Rate Application**

1.0 ADMINISTRATION (EXHIBIT 1)

1.0-VECC-1
Reference: Exhibit 1,page / Exhibit 2, DSP, Section 4/Exhibit 2, Appendix B

"*In particular, customers showed a strong preference for a proactive replacement instead of run to failure*."

a) What assets is this finding being applied to in the proposed Distribution Asset Plan? Specifically, what are the capital cost implications of implementing this finding in the 2021 capital plan?
b) Please explain how HHHI came to this conclusion, specifically please identify the Customer Engagement Results which HHHI is relying upon for this statement.

2.0 RATE BASE (EXHIBIT 2)

2.0-VECC-2
Reference: Exhibit 1, Table 29

a) The average capital contribution as a percentage of system access for the period 2016 through 2019 (actuals) is approximately 60%. The forecast capital contributions for the 2021 test year is approximately 45% of the estimated system access budget. Please explain how the capital contribution estimate for 2021 was derived and why the forecast amount differs significantly from the past average.

2.0-VECC-3
Reference: Exhibit 2, page 35-36, Table 29 / EB-2015-0074, Exhibit 2, Tab 2, Schedule 2, page 56

In EB-2015-0074 HHHI makes the following statement: *A significantly larger scope of Pole Trans replacements in 2014 (Lakeview Subdivision in Acton) was performed as compared to similar work on Bower Street in 2013*.
In this application HHHI explains that it "*re-evaluated the distribution to Lakeview subdivision and decided it was reasonable to expand the scope of work to include relocating overhead rear-lot distribution to underground front lot distribution to enhance reliability for customers in 24 the area that had been affected by the ice storm of December 2013*."

a) Did the conversion to conversion underground result in any of the prior pole transformer replacements in the Lakeview subdivision being made redundant? If yes, please identify the amount of investment in prior 5 years in the Lakeview subdivision that was made redundant due to the conversion to underground.
b) Please provide the business case that was undertaken to support conversion to underground front lot. Specifically, please provide the alternative cost of rehabilitation of the existing plant (i.e. like for like).
c) The $1 million cost of this project represents over 10% of the average HHHI annual capital budget, and yet HHHI explains it was not anticipated in the 2016-2020 DSP. Please explain how it was that such a large project was unanticipated in August of 2015 (filing date of EB-2015-0074) and yet in-service by the end of 2016.

2.0-VECC-4
Reference: Exhibit 2, Appendix 2-AA

a) Please revise Appendix 2-AA to show the actual 2020 capital spending to date and (separately) for forecast remaining amounts to be spent in 2020.
b) Please also show in the revised Appendix 2-AA for each asset category the actual and forecast capital contributions.

2.0-VECC-5
Reference: Exhibit 2, page 60

a) Please explain how the 2021 "Municipally Driven Projects" amount of $939,918 is estimated.

2.0-VECC-6
Reference: Exhibit 2, Table 41, page 85

a) With respect to the TS cost overruns, please explain what incremental "Commissioning Costs" are comprised of (as separate from the SCADA, labour, equipment and materials costs listed in Table 41).

2.0-VECC-7
Reference: Exhibit 2, Section 2.3.7, page 91

a) HHHI has made two adjustments to the standard Kinectric's Report Service Life rates: Transformer Station Equipment and Administrative Buildings. Are these asset life adjustments the result of an earlier study undertaken by HHHI?

2.0-VECC-8
Reference: Exhibit 2, DSP, Section 3.44, pages 182-, Section 4.6

a) Please explain and contrast the advantages and disadvantages of running polemount transformers to failure as compared to a proactive strategy for replacement of these assets. Specifically, what is HHHI's view of the cost and reliability trade-off as between a run-to-failure strategy and proactive test and replace of polemount transformers.

2.0-VECC-9
Reference: Exhibit 2, DSP, Section 4,12,2, page 252

System Renewal						
Pole Replacements	End of Life Assets	624,199	647,375	679,744	713,731	749,418
Poletrans Replacement Program	Obsolete Equipment	809,294	790,157	165,000	382,177	50,000
Porcelain Insulator Replacement Program	End of Life Assets	51,459	53,003	54,593	56,231	57,918
Transformer Replacement Program	End of Life Assets	222,791	435,329	187,889	120,525	443,241
Pole Line Rebuild Program	End of Life Assets	0	0	25,000	378,020	407,907
Substation Equipment	End of Life Assets	615,397	700,253	242,444	83,760	674,760
Distribution Equipment Renewal	End of Life Assets	38,950	42,649	72,600	41,334	42,160
Total		2,362,090	2,668,766	1,427,270	1,775,778	2,425,404

General Plant						
Equipment & Tools		525,000	265,000	330,000	295,000	435,000
Software & Systems		233,057	240,400	173,140	397,260	158,140
Building Equipment		70,000	77,000	103,800	2,000	25,000
Sub-Total		828,057	582,400	606,940	694,260	618,140

a) HHHI proposes to spend $809,294 on "Poletrans Replacement Program" in 2021 under the auspices of replacing obsolete equipment. Why could this program not be executed in a more levelized fashion over the 5-year program, that is spending approximately $440k in each year of the DSP plan?
b) Similarly, "Equipment and Tools" spending in 2021 of $525k is significantly higher than the five-year average of approximately $382k. Why could this program not be undertaken on a more evenly paced program of asset replacement?

2.0-VECC-10
Reference: Exhibit 2, Section 4.12.3.1.4

The following municipally driven projects were presented at the above reference:

1. Trafalgar Road;
2. 10 Side Road/ Winston Churchill Blvd.;
3. Highway #25/ Campbellville Road.

a) Are these all the projects representing the $1,366,230 identified for 2021 under the category "Municipally Driven Projects" (System Access Appendix 2-AA)?
b) What are the forecast capital contributions for these projects?
c) Please provide an update as to the status of these projects proceeding in 2021 and include any correspondence or agreements from the affected municipalities which indicate the projects are to be completed in 2021.

2.0-VECC-11
Reference: Exhibit 2, Appendix E – Capital Projects/ Appendix 2-AA

We are unable to reconcile Appendix E with the information provided in Appendix 2-AA. For example: system service projects are not distinguished in Appendix E as to whether they are Feeder Improvements or Voltage

Conversions in Appendix 2-AA. The Garage Roof Replacement of 60k in Appendix E is less the "Building Equipment" category in Appendix 2_AA. The "Automated Switches & Scada Integration amount of $243,887 in Appendix 2-AA is more than the project plan listed as "SCADA Switch/Device Integration of $203,566 at page 720 of Appendix E; etc..)

a) Please create a table using the listing of projects for 2021 in Appendix E which and reconciles with Appendix 2-AA. Or if such a table already exists in the evidence please provide the reference.

2.0-VECC -12

Reference: Exhibit 2, pages 99-104
Exhibit 3 page 30

Preamble: The Application states:
"*HHHI calculated the cost of power for the 2020 Bridge Year and the 2021 Test Year based on the results of the load forecast discussed in detail in Exhibit 3. The commodity prices used in the calculation were prices published in the Board's Regulated Price Plan Prices. Should the Board publish a revised Regulated Price Plan Report prior to the Board's Decision in the application, HHHI will update the electricity prices in the forecast*".

a) Please reconcile the kWh values by rates class used in the calculation of the cost of power commodity charges with the load forecast set out in Exhibit 3. In doing so, please demonstrate that the kWh usage associated with HHHI's Market Participant(s) has been excluded from the calculation of the commodity costs.
b) Are charges for transmission service paid directly by the Market Participant(s) to the IESO or to HHHI through the RTSRs? If the former, please demonstrate that the power usage by HHHI's Market Participant(s) has been excluded from the determination of the Transmission Costs included in the Cost of Power.

3.0 OPERATING REVENUE (EXHIBIT 3)

3.0-VECC-13

Reference: Exhibit 3, page 6

Preamble: The Application (page 6) states: "*With the assistance of Borden, Ladner and Gervais, LLP, HHHI used the same regression analysis methodology approved by the Ontario Energy Board (the "OEB" or "Board") in the 2016 HHHI Cost of Service ("COS") application (EB-2015-0074)*.".

a) Please clarify whether, in its EB-2015-0074 Decision, the OEB: i) actually approved HHHI's load forecast methodology or ii) accepted the load forecast included in the Settlement Proposal filed during the proceeding.

3.0-VECC-14

Reference: Exhibit 3, pages 7-8 and 22-23
Load Forecast Model, Rate Class Energy Model Tab

a) Is the methodology used to translate historical use by customer class into weather normal historical use by class (Table 2) the same as the methodology used to translate the non-weather normal 2021 forecasts by customer class into the forecast 2021 weather normalized values?

3.0-VECC-15

Reference: Exhibit 3, pages 14 and 18
Load Forecast Model (COS), Purchased Power Model Tab

Preamble: The Application states: "*An equation to predict total system purchased energy is developed using a multivariate regression model with the independent variables outlined below*."
In the Load Forecast Model (Purchased Power Model Tab) there is no column for HHHI purchases from embedded generators.

a) Please confirm that dependent variable used in the regression equation (i.e., Column D in the Purchased Power Model Tab) is the sum of IESO power purchase by HHHI and usage by HHHI's Market Participant customer(s).
b) Does HHHI purchase power from any embedded generators (e.g. microFit customers)? If yes, are these purchases included in the purchased power values used as the independent variable in the regression analysis?

i. If purchases from embedded generators have not been included, please update the load forecast model and results accordingly.

c) With respect to Table 6 (page 18), please confirm that – contrary to the title of the Table – the actual purchase values shown include usage by the Market Participant(s). (Note: The values reconcile with Column D -the sum of IESO purchases and Market Participant(s) use in the Purchased Power Model Tab).
d) With respect to Table 6, please confirm that the predicted purchased power values for 2020 and 2021 include usage by the Market Participant(s).
e) Please provide the 2020 and 2021 predicted power purchases excluding usage by HHHI's Market Participant(s) and explain how they were derived.

3.0-VECC-16
Reference: Exhibit 3, page 15

a) Please confirm that the -1.5 coefficient for CDM means for every kWh of persisting CDM monthly purchases are reduced by 1.5 kWh.
b) In HHHI's view does this result make sense intuitively and, if yes, why?
c) Please provide an alternative purchased power model (i.e., coefficients and statistical results) along with the resulting 2020 and 2021 load forecast where:
    i. The monthly purchased power values used to estimate the regression equation are increased by the persisting monthly CDM and the regression equation is estimated using the balance of the explanatory variables as set out in the Application.
    ii. The 2020 and 2021 monthly purchases are first forecast using this regression model and the forecast values for the explanatory variables per step (i).
    iii. The resulting 2020 and 2021 forecast monthly purchases are reduced by the persisting CDM forecast for each month as set in the Application.
d) It is noted that the regression model does not include any independent variables related to the level of economic activity (e.g., employment levels or GDP levels) or number of customers/connections. Did HHHI test any such variables to determine whether their "coefficients" were statistically significant and their inclusion improved the overall model?
    i. If not, why not?
    ii. If yes, what variables were tested and what were the results?

3.0-VECC-17

Reference: Exhibit 3, pages 8 and 20-21

Preamble: The Application states (page 20): "*For the Residential and General Service less than 50 kW classes, the growth factor resulting from the geometric mean analysis from 2010 to 2019 is applied to the 2019 customer numbers to determine the forecast of customer / connections for 2020. Then the factor is applied again to 2020 Bridge Year forecast to determine the 2021 Test Year forecast. For all other classes, HHHI has assumed the number of customers / connections will remain at the 2019 level in 2020 and 2021.*"

The Application (page 8) states: "*Customer/Connection values are on a year-end basis and Streetlighting, Sentinel Lights and Unmetered Scattered Loads are measured as connections. The customer/connection values are converted to an average basis for the purposes of rate design.*"

a) Please provide the actual customer/connection counts by customer class for June 2020 and July 2020.
b) Please explain how the "average count" was calculated for the purposes of rate design.

3.0-VECC-18

Reference: Exhibit 3, page 24

a) The Application makes adjustments to the load forecast for 2021 related to three specific customers. (e.g., average of 12 monthly values). What criteria did HHHI use in order to determine that specific adjustments were required only for these three cases?
b) Are there any GS 50-999 or GS 1,000-4,999 customers whose usage in the first three months of 2020 was 10% or more greater than in the first three months of 2019? If, yes, how many customers met this criteria and what was the increase usage over the three months for each class related to these specific customers?
c) With respect to Customer 1, please explain the basis for the 9,108 kW billing demand adjustment.

3.0-VECC-19

Reference: Exhibit 3, pages 25-27

a) Please provide a schedule that sets out the HDD and CDD values for: i) the period April 1, 2019 to September 30, 2019 and ii) the period April 1, 2020 to September 30, 2020.
b) Please provide a schedule that sets out HHHI's actual monthly power purchases for April through September 2020, using the same definition of power purchases as used in the load forecast model.
c) Using the actual Heating and Cooling Degree Days per part (b), HHHI's purchase power model (per Purchased Power Model Tab), HHHI's 2020 forecast for the explanatory variables please provide the resulting prediction for the power purchased for the months of April through September 2020.
d) Please provide a revised version of Table 17 where the COVID-19 adjustment is applied to the predicted billed energy by class after weather normalization and the specific GS customer adjustments.
e) Please confirm that the forecast set out in Table 17 assumes that the impacts experienced to date from the COVID-19 pandemic will continue for the balance of 2020 and all of 2021. What is the basis for this assumption?
f) Is it HHHI's assumption that none of the COVID-19 pandemic impacts it has incorporated in its 2021 load forecast will be addressed by the Deferral Accounts the Board has established in Response to the COVID-19 Emergency?
    i. If yes, what is the basis for this assumption?
    ii. If no, why is the COVID-19 adjustment required?
g) What would be the 2021 distribution revenue at existing (2020) rates based on the load forecast without the COVID-19 adjustments?

3.0-VECC-20

Reference: Exhibit 3, pages 16 and 23
Load Forecast Model (COS), CDM Tab
Participation and Cost Report, April 2019, LDC Progress Tab

a) Please provide a copy of the OPA Report that supports the CDM savings values used in the CDM Tab (Rows 3-7) for the years 2006-2010.
b) Please provide a copy of the IESO Report that supports the CDM savings values use in the CDM Tab (Rows 8-11) for the years 2011-2014.
c) The Participation and Cost Report (LDC Progress Tab) shows 3,287.6 MWH of savings in 2018 from 2018 programs. However, the CDM Activity Tab only shows 2,745.9 MWh. Please reconcile.

d) Given that the savings from 2018, 2019 and 2020 programs included in the load forecast (CDM Tab, Rows 15-17) are unverified results why isn't it necessary to have an LRAMVA threshold for 2021 that reflects the level of savings included from these years' programs?

3.0-VECC-21
Reference: Exhibit 3, pages 50-51

a) Why are there no revenues shown for Retail Services (#4082) or Service Transaction Requests (#4084)?

3.0-VECC-22
Reference: Exhibit 3, pages 54-55

a) Why is 2019 the only year in which there are revenues from Hydro One for the administration of the Affordability Trust Fund?
b) Where is the OM&A associated with Other Utility Operating-Recoverable Work and the administration of the Affordability Trust Fund recorded?
c) With respect to Other Utility Operating-Recoverable Work, please provide the actual associated OM&A for 2016 and the forecasted associated OM&A for 2021.

4.0 OPERATING COSTS (EXHIBIT 4)

4.0 -VECC -23
Reference: Exhibit 4, pages 31-

Table 15 - Summary of Climate Change Plan

Description	Amount
Supporting Low-Carbon Mobility	$66,700
Preparing for EV Charging Impacts	$80,000
Renewable / Low-Carbon Energy	$20,000
Energy Conservation Initiatives	$60,000
Climate Change Coordinator	$53,000
Total	**$279,700**

a) Under what legislative or other legal mandate is HHHI required to participate in the "climate change emergency" declared by the Town of Halton Hills? Please provide the specific municipal bylaw or other legislation HHHI is relying upon to support this requirement.
b) Please provide the cost-benefit analysis that was undertaken in support of HHHI's Climate Change Proposal.
c) Please identify any capital spending undertaken or planned within the rate plan term for this initiative. Please provide the references in the filed Distribution System Plan for these initiatives.
d) Are any employees previously assigned to CDM responsibilities now be assigned to the Climate Change Proposal initiatives? If so please identify how many.

4.0 -VECC -24
Reference: Exhibit 4, Appendix 2-K, page 51-52

a) Please amend Appendix 2-K to include two rows showing the total amount of OM&A capitalized and expensed in each year.
b) Do the FTEs shown in years 2016 through 2019 include any staff employed on CDM initiatives?
c) What is the current FTE compliment at HHHI?

4.0 -VECC -25
Reference: Exhibit 4, page 38

Table 17 - Transformer Station Incremental OM&A Costs

Transformer Station Costs	2019	2020	2021
Control Room and Station Maintenance		$73,050	$90,000
Expendable Materials		$1,300	$1,300
Fibre Cable, Internet, Phone Line and Security	$1,086	$16,300	$16,530
Property Tax		$43,030	$44,321
Snow Removal		$4,000	$4,000
Building Maintenance		$1,000	$1,000
Property Insurance			$32,115
Total	$1,086	$138,680	$189,266
Incremental Costs	$1,086	$137,594	$51,672
Total Incremental Costs			$190,352

a) Please explain the derivation of the $51,672.

4.0 -VECC -26
Reference: Exhibit 4, Appendix 2-JC

Typically, Appendix 2-JC (OM&A by programs) includes items such as Bad Debts, Collections, Information Technology, Tree Trimming, Locates, Property Insurance, Fleet management in addition to a breakdown of operations and maintenance costs into more detail - like metering, inspections etc. HHHI's Appendix 2-JC is essentially the same as Appendix 2-JA and does not include the costs of any individual programs or areas of activity in 2016 through 2021. Appendix 2-JB which shows annual changes in OM&A and Table 8 shows OM&A cost trends in much greater detail indicating that that HHHI does track OM&A costs at a more granular level.

a) Please provide a version of Appendix 2-JC which shows the OM&A by programs (like Table 8) or if such a chart is already provided in the evidence a reference to that table.

4.0 -VECC -27
Reference: Exhibit 4, page 40

Table 21 - PWU Annual Wage Increase

Union Staff Annual Wages Increase

	Actual	Actual	Actual	Actual	Actual	Budget effective date	Budget effective date
	01-Apr-16	01-Apr-17	01-Apr-18	01-Apr-19	01-Oct-19	01-Apr-20	01-Apr-21
Annual Wages Increase	2.00%	2.00%	2.20%	1.30%	1.00%	2.00%	2.25%

a) What is the anticipated time frame for the union contract negotiations to resume?
b) It is unclear from the referenced table as to why 2019 increases were 1 to 1.3% whereas the 2020 and 2025 amounts are higher. Under the agreed extension of the current contract is there an agreement as to the wage increases for 2020 and 2021? If so what is that amount?
c) Do Non-Union/Management increases generally follow that for Union employees?

4.0 -VECC -28
Reference: Exhibit 4, Table 38 Shared Services

a) Please explain the large increase in services contracted from SouthWestern Energy Inc since 2016. What work is performed by this company?
b) What is the markup rate of this company?

4.0 -VECC -29
Reference: Exhibit 4, Table 38 Shared Services

a) Please explain the large increase in services contracted from 2008949 Ontario. Specifically, was vegetation management previously done internally or by contractors other than this company?
b) Does this company do all or a portion of HHHI's vegetation management? If a portion please clarify as to proportion of work completed internally, by other contractors and by 2008949.
c) Does this company use its own vehicles for tree trimming and other vegetation management services?
d) Does this company (2008949) have a commercial name that can be

identified by customers when it is working?
e) What is the markup rate of this company?

4.0 -VECC -30
Reference: Exhibit 4, Table 38 Shared Services

a) Are all the amounts paid to Southwestern and 200849 included in the 2016 through 2019 actual OM&A costs as presented in Appendix 2-JA?
b) If some of these costs are capitalized please explain under what USOA accounts the capitalized amounts would be found and what those amounts were (and are estimated to be) in the 2016-2021 period.
c) What the amounts paid to date to date to these companies in 2020?
d) The 2021 application includes all the forecast costs of the Utility. What is HHHI forecast for the services that it expects SouthWestern Energy and 2008949 to undertake in 2021 and that it has included for rate recovery?

4.0 -VECC -31
Reference: Exhibit 4, Table 39

a) What are the actual amounts paid for EDA membership in 2016 through 2020 and the amount included in rates for 2021?

4.0-VECC-32
Reference: Exhibit 4, Appendix 2-M, Regulatory Costs

a) What was the most recent annual assessment invoice cost (i.e. 2019 or 2020) from the OEB?
b) Please provide a table showing the forecast $280,000 one-time costs for this application in the categories: Legal, Consultants, Customer Engagement internal staff and Intervenors and show in the amounts spent to date on each category.

4.0-VECC-33
Reference: Exhibit 4, Section 4.7.1

a) Please provide the amount of LEAP funding provided to Links2Care in each year 2016 -2020.
b) Is HHHI provided a report on the LEAP funding dispersed in each year? If so please provide than amount for each year 2016- 2020 (or 2019).
c) We visited the Link2Care website for Halton related items but were unable

to find any link to LEAP assistance (though we did find links to phone assurance programs). Is HHHI aware of how Links2Care communicates the availability of LEAP assistance?

4.0 -VECC -34
Reference: Exhibit 4, page 117
LRAMVA Model, Tab 5

b) Have the 3,287,636 kWh of savings in 2018 from 2018 programs been verified by the IESO or any other third party?

5.0 COST OF CAPITAL AND RATE OF RETURN (EXHIBIT 5)

5.0-VECC-35
Reference: Exhibit 5, Section 5.5.4, pages 14-5

a) Please reconcile the Interest Swap #1 amount of $23.0 million with the amount of $22,080,143 shown in Appendix 2-OB.

5.0-VECC-36
Reference: Exhibit 5, Section 5.5.4, pages 14-5

The Table below is extracted from the ongoing proceeding of Niagara Peninsula, EB-2020-0040.

Source: Niagara Peninsula Energy Ince Appendix 2OB EB-2020-0040 Year 2020

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]
1	Non-revolving term loan payable	Scotiabank	Third-Party	Fixed Rate	30-Sep-15	5	$ -	0.0267
2	Term Loan payable	TD Bank	Third-Party	Fixed Rate	27-Jun-17	10	$ 10,000,000	0.0281
3	Term Loan payable	TD Bank	Third-Party	Fixed Rate	3-Dec-18	10	$ 10,000,000	0.03671
5	Term Loan payable	Scotiabank	Third-Party	Fixed Rate	6-Nov-19	5	$ 10,000,000	0.02698
6	Term Loan payable	Meridian Credit Union	Third-Party	Fixed Rate	13-Sep-16	10	$ 20,000,000	0.026
7	Term Loan payable	TD Bank	Third-Party	Fixed Rate	1-Aug-19	10	$ 25,600,000	0.0276
8	Term Loan payable	Scotiabank	Third-Party	Fixed Rate	6-Nov-19	5	$ 7,234,630	0.02698
9								
Total							$ 82,834,630	2.84%

a) The most recent debt amounts negotiated in the summer and fall of 2019 by that Utility show an average interest rate of around 2.7%. HHHI has negotiated a 30-year swap rate at 4.095%. Please explain why HHI believe a longer term, potentially at a higher rate of interest, was preferrable to a shorter term at lower rates.
b) Please explain how HHHI ensured that the 4.095% was the best rate it could receive in the market at the time of its negotiation.

5.0-VECC-37
Reference: Exhibit 5, Section 5.5.4, page 12

a) Please complete Appendix 2-OB (Exhibit 5, page 12) to show the start date and term of all of the debt instruments.
b) Please reconcile the total amounts shown in Appendix 2-OB (113,597,337) with the amounts shown at page 12 (69,561,039) and the difference in interest rates (2.13% and 3.476%)

5.0-VECC-38
Reference: Exhibit 5, Section 5.5.4, pages 12

a) Please reconcile amounts shown for long-term debt in the RRWF (Niagara_Peninsula_Energy_Inc_Appl_2020_Rev_Reqt_Work_Form_20200818.XLSM) with the amounts shown in Appendix 2-OB (page 12).

6.0 CALCULATION OF REVENUE DEFICIENCY/SURPLUS (EXHIBIT 6)

6.0-VECC-39
Reference: Exhibit 6, Table 10, page 15

a) HHHI projects a revenue deficiency of $5,422,387 and a gross deficiency of $7,377,397. What amount of these deficiencies are attributable to the new HHHI owned transfer station? Please show the calculation for this attribution.

7.0 COST ALLOCATION (EXHIBIT 7)

7.0 – VECC –40

Reference: Exhibit 7, pages 5-6
Cost Allocation Model, Tab I4

Preamble: The Application states: "*A weighting factor was determined by assigning the Residential customer class a factor of 1.0, as required, and determining the relative weights of the rest of the classes. As per Table 7-1, HHHI applied a weighting factor of 1.0 for Residential. For General Service less than 50 kW, General Service 50 to 999 kW and General Service 1,000 to 4,999 kW have a factor of 0.0 since any costs are recovered fully through capital contributions received from those customers.*"

a) With respect to Tab I4, please confirm that the asset values set out in Column C are the gross asset values prior to the removal of capital contributions.
b) Tab I4 shows $120,512 in contributed capital that is attributed to Services (Acct. 1855). Does this amount represent the actual contributed capital paid by customers for their Services or is it simply based on an allocation of the total contributed capital to assets?
    i. If based on an "allocation", please provide the 2021 cumulative value for the contributed capital HHI is forecast to receive as of 2021 for customers' Services.
c) Are the Services assets used to supply GS customers owned by HHI or the customers themselves?
d) If some or all of the Services assets used to supply GS customers are owned by HHHI and HHHI is responsible for the ongoing OM&A costs related to these assets then:
    i. In the Cost Allocation Model, are there OM&A costs attributed to Services assets that are subsequently allocated to customer classes?
    ii. If yes, please indicate where in the CA model this occurs and if the GS classes are attributed a portion OM&A costs for these assets.
    iii. If the GS classes are not attributed a portion of the OM&A associated with the Services assets, what is HHHI's estimate as to the annual OM&A cost for 2021 related to the Service assets used to supply each of these customer classes?
e) Do the Streetlight, Sentinel or USL customers have Services assets that

are owned and/or maintained by HHHI? If yes, please explain why the Services weighting factors for these classes are all zero.

7.0 – VECC –41
Reference: Exhibit 7, page 7

a) Please explain why more up to date costs for installing different types of meters were not determined and used in the Cost Allocation Model.

7.0 – VECC –42
Reference: Exhibit 7, page 8
Cost Allocation Model, Tab I6.2

a) Please confirm that each Streetligting device is separately connected to HHHI's distribution system such that the number of devices equals the number of connections. If not confirmed, please explain the relationship and indicate the necessary revisions to Tab I6.2.

7.0 – VECC –43
Reference: Exhibit 7, pages 12-14
Cost Allocation Model, Tab 01

a) Please explain more fully how/why setting the Revenue to Cost Ratio for Residential at 105.67% would cause a significant rate increase for that class as suggested on page 14.

8.0 RATE DESIGN (EXHIBIT 8)

8.0 –VECC - 44
Reference: Exhibit 8, page 13

a) For the GS<50 class where the Minimum System with PLCC Adjustment (Ceiling Fixed Charge) from Cost Allocation from is $24.59, please reconcile the proposal to increase the fixed charge from $29.39 to $48.43 with the Board's Filing Guidelines , Chapter 2, page 54 which state:

   "*If a distributor's current fixed charge for any non-residential class is higher than the calculated ceiling, there is no requirement to lower the fixed charge to the ceiling, <u>nor are distributors expected to raise the fixed charge further above the ceiling for any non- residential class</u>.*" (Emphasis added)

8.0 –VECC - 45

Reference: Exhibit 8, pages 16-17 and Appendix 8-3
Cost Allocation Model /RRWF, Rate Design Tab

a) Please indicate where/how the monthly reserve capacity billing quantity has been included in the cost allocation model revenue and the determination of total revenues at the proposed rates.
b) Will the Capacity Reserve Charge be applied in all months, including those when the customer's generation is not operating for part of the month and standby capacity is required?
c) The proposed tariffs for 2021 (Appendix 8-3) do not include the Standby Charge. Please provide draft of the proposed Standby Charge tariff sheet including the wording that will be used to describe how the billing determinants will be calculated and the rate applied.
d) Will the load displacement customer's load impact the ST charges levied on HHHI by HONI?
    i. If yes, since HON's ST charges are based on gross load billing, does HHHI proposed to levy LV charges on a "gross load" basis?

8.0 –VECC – 46

Reference: Exhibit 8, page 21 and Appendix 8-3

Preamble: The Application states: "For the purposes of providing a complete 2021 Proposed Tariff of Rates and Charges, HHHI has utilized the current 2020 Retailer Service Charges as issued by the OEB Decision and Rate Order dated November 28, 2019 in proceeding EB-2019-0280 and shown in HHI has forecasted its retail services revenues based on the updated charges and include the costs of providing retail services in revenue requirement".

a) What is the basis for the 2021 Retail Service Charges (Exhibit 8, page 81)?

8.0 –VECC – 47

Reference: Exhibit 8, page 27 / Exhibit 3, page 51

Preamble: The Application states: "HHHI understands and accepts that the Wireline Pole Attachment Charges will be updated with the 2021 rates once approved by the Board. For the purposes of providing a complete 2021 Proposed Tariff of Rates and Charges, HHHI has utilized the current 2020 Wireline Pole Attachment Charges as provided in the cover letter issued by the OEB in its Decision and Rate Order dated November 28, 2019 in proceeding EB-

2019-0280 in the amount of $44.50 per attacher per year per pole."

a) What was the pole attachment charge used to forecast the 2021 Pole Rental revenue – per Exhibit 3, page 51?

8.0 –VECC – 48
Reference: Exhibit 8, page 30

a) It is noted that in 2019 the charges from HONI increase by over 30% despite a decrease in the billing demand. Please provide further details on the basis for the 2018 and 2019 charges and the reasons for the significant increase.
b) It is noted that in 2020 the charges from HONI increased again by more than 30%. Please provide further details on the basis for the forecast 2020 charges so as to explain the reasons for the significant increase.

9.0 DEFERRAL AND VARIANCE ACCOUNTS (EXHIBIT 9)

9.0 –VECC -49
Reference: Exhibit 9, page 23

"On September 25, 2017, HHHI made an application to the OEB (EB-2017-0215) requesting the approval of a deferral and variance account to record an adjustment to the revenue requirement in the amount of $330,259 per year"

Table 11 - Depreciation Adjustment Forecasted Variance Calculations

Depreciation Adjustment	$
Annual Depreciation not included in 2016 Rates	330,264
Monthly Depreciation Adjustment Amount	27,522
Forecasted Transactions from January 1, 2020 to April 30, 2021 (16 months)	440,352

a) EB-2017-0215 refers to an application by Natural Resource Gas Limited. Please provide the correct reference for this application. Please confirm the proceeding in question and the correct reference is EB-2017-0045.
b) The derivation of the $27,522 in Table 11 is unclear to us, please clarify.

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