ECONALYSIS CONSULTING SERVICES

34 KING STREET EAST, SUITE 630, TORONTO, ONTARIO M5C 2X8

www.econalysis.ca

August 20, 2018

VIA E-MAIL

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board

Dear Ms. Walli:

Re: ENERGY + INC. 2019 RATES EB-2018-0028
VECC Interrogatories

In accordance with Procedural Order No. 1 in the above noted proceeding please find enclosed the interrogatories of VECC. We have also directed an email copy of the same to the Applicant.

Yours truly,

Mark Garner

Consultant for VECC

Ms. Sarah Hughes, CFO Energy+ shughes@energyplus.ca

REQUESTOR NAME	**VECC**
TO:	**Energy+ Inc. (“E+”)**
DATE:	**August 20, 2018**
CASE NO:	**EB-2018-0028**
APPLICATION NAME	**2019 Rates**

EXHIBIT 1 – ADMINISTRATION AND CUSTOMER ENGAGEMENT

1-VECC-1
Reference: E1/pgs.72-73, 98, 112

a) Please explain what specific customer feedback was provided that caused Energy+ to defer the additional third overhead feed line into the Town of Paris? (pg.98).
b) Please explain what the purpose of the “Service Order module” that was to be integrated into the My Account Online portal, but was subsequently deferred due to customer feedback (pg.112).

1-VECC-2
Reference: E1/pg.89

a) Please provide the calculation which supports the estimated typical cost of the planned new facilities of $0.68 per month per customer.

1-VECC-3
Reference: E1/pg.389

a) What was the total cost of the Innovative Research customer engagement activities and surveys?

EXHIBIT 2 – RATE BASE AND CAPITAL EXPENDITURES

2-VECC-4
Reference: Exhibit 2, Section 2.7.2.1, Table 2-29

a) Actual capital contributions in 2015 and 2016 were 56% and 50% respectively of system access costs. The equivalent average forecast for 2019 through 2022 is only 19%. Please explain why E+ is expecting capital contributions in the future to be a much lower portion of system access funding.
b) Please explain how the capital contribution forecast was derived
c) Please provide the actual capital contributions received in 2017.
d) Please provide the contributions for 2018 to date.

2-VECC-5
Reference: Exhibit 2, Appendix 2-AA

a) Please provide a progress update on the following projects including how much of the 2018 forecast budget has been spent to date:
   i) Fountain St. Relocations
   ii) Powerline Road
   iii) Servicing Industrial (underground)
   iv) Grand Ridge Drive
   v) Burtch Road
   vi) Cockshutt Road

2-VECC-6
Reference: EB-2013-0116, 1.1-SEC-1 Response to Interrogatories, Feb 25, 2014.

a) Please confirm that in E+'s last cost of service application, EB-2013-0016 (Cambridge North Dumfries) that CND underspent its OEB Approved 2010 base year budget by approximately 16% ($1.6 million).
b) The following table was provided in EB-2013-0116 and shows the capital expenditure plan presented to the CND Board of Directors (dated January 18, 2013). Please provide the actual spending for these categories for the CND utility for the period 2013 through 2015.

Capital Investment Plan Summary

CAMBRIDGE AND NORTH DUMFRIES HYDRO INC.

CAPITAL EXPENDITURE FORECAST

($'000)

	Budget 2012	**Projected 2012**	**Budget 2013**	**Budget 2014**	**Budget 2015**	**Budget 2016**	**Budget 2017**
Land and Buildings	$ 1,348	$ 492	$ 483	$ 5	$ 100	$ 100	$ 100
Transformer Station and Equipment	250	236	3	-	-	-	15,000
Lines - Overhead - New	3,649	2,194	4,910	1,930	2,100	950	850
Lines - Overhead - Rebuilt	2,508	2,080	7,160	7,182	4,100	3,145	3,215
Lines - Underground - New	2,156	1,835	5,481	7,281	2,000	2,800	2,800
Lines - Underground - Rebuilt	1,230	633	2,200	2,260	1,800	915	1,220
Line Transformers	1,215	437	2,003	2,006	2,000	2,400	2,800
Meters	479	464	915	887	500	600	700
Office Equipment and Furniture	59	41	141	-	50	60	70
Computers	1,107	872	1,958	1,161	1,000	1,200	1,400
Vehicles	550	159	592	925	700	800	900
Tools and Equipment	300	52	46	20	50	60	65
Gross Capital Expenditure	14,851	9,495	25,892	23,657	14,400	13,030	29,120
Less: Contributed Capital / Subdivisions Assumed	(1,508)	(1,566)	(7,072)	(7,406)	(3,000)	(2,300)	(2,400)
Net Capital Expenditure	$ 13,343	$ 7,929	$ 18,820	$ 16,251	$ 11,400	$ 10,730	$ 26,720

2-VECC-7
Reference:

a) Please provide the total annual capital expenditures for BCP for each year 2012 through 2015.
b) Please provide the total capital contributions for BCP for each year 2012 through 2015.

2-VECC-8
Reference: Exhibit 2, Section 2.7.3.2 & Appendix N: Facilities Business Plan, pg. 1032

a) Please provide the square footage per management/ administration FTE and separately for operations and maintenance FTEs before and after the relocations.
b) Why is the sq. ft. per customer as shown in Figure 1 of the Facilities Plan a relevant metric of space needs?
c) Does the sq. ft. per employee as shown by the black line in Figure 1 show the final figure once all new facilities are in place (i.e. 2020)? If not please extend the table to show the final figures once all new facilities completed.

2-VECC-9
Reference: Exhibit 2, section 2.7.3

a) In what year was 65 Dundas building ($1.5) removed from the continuity schedules of Energy +?

2-VECC-10
Reference: Exhibit 2, DSP, pg. 138

a) Please provide the customer interruption hours by cause code as shown in Table 206 but separately for BCP and CND for the years 2014 and 2015.

2-VECC-11
Reference: Exhibit 2, DSP, pgs. 218, 271

a) Figure 4-16 shows the impact of the system investment is to actually increase slightly OM&A costs. Please explain why this would be the case give that the average system renewal spending will rise during 2019-22 period to $8,154,223 from the 2014-2018 average system renewal spending of $6,694,000 (Appendix 2-AB).

2-VECC-12
Reference: Exhibit 2, 2017 Asset Condition Assessment

a) For each asset category listed in Figure 5, the Health Index Results please provide the following:
   a) total population of assets;
   b) total population of assets physically tested;
   c) description of physical test as per response to b);
   d) total population of assets only visually inspected;

2-VECC-13
Reference: Exhibit 2, Asset Condition Assessment, pg. 845

a) Table 2 (Summary of Flagged for Action) describes the replacement strategy for wood poles as proactive and reactive. Is the policy of a proactive strategy to replace wood poles a departure from Energy+'s (CND) previous distribution system plan. If yes, please explain the reason for the change in policy.

2.0 –VECC -14
Reference: Exhibit 2, Tables 2-24 and 2-25

a) Please provide a schedule that sets out the calculation of the $78,123,704 forecast for Power Purchase costs.
b) If Embedded Distributor-Waterloo North is included in the calculation (as Table 2-25 suggests), please explain why since it is a WMP (per Exhibit 3, page 26).
c) Please explain how the volumes for each customer class used to calculate the Global Adjustment were determined.

EXHIBIT 3 - REVENUES

3.0 –VECC -15
Reference: Exhibit 3, pages 9 and 11 (Tables 3-5 and 3-7)
Exhibit 3, pages 4 and 19
Load Forecast Model, Rate Class Customer Model Tab

Preamble: At page 4, lines 8-12, E+ states that revenue figures for 2017 are a forecast based on 11 months of actual data.

a) Please explain how the historical annual customer/connection count for each class was calculated (e.g., year-end values, average of 12 months, etc.).
b) For purposes of the Rate Class Customer Model Tab, please confirm whether the 2017 customer counts are based on 12 months of actual data. If not, please update the load forecast using 12 months of actual 2017 customer count data.

3.0 –VECC -16

Reference: Exhibit 3, page 4 (lines 8-12) and page 6 (lines 9-10)
Load Forecast Model, Purchased Power Model and Rate Class Energy Model Tabs

Preamble: At page 4, lines 8-12, Energy+ states that revenue figures for 2017 are a forecast based on 11 months of actual data. At page 6 (lines 9-10), Energy+ state that the regression analysis used actual data up to the end of 2017.

a) Please confirm that, for purposes of the regression analysis used to predict weather normal purchases (Purchased Power Model Tab), 12 months of actual 2017 purchased power data was available and used. If not, please re-estimate the models and provide an updated load forecasts based on 12 months of actual 2017 purchased power data.
b) For purposes of the Rate Class Energy Model Tab, please confirm whether the 2017 energy use by customer class is based on 12 months of actual data. If not, please update the load forecast using 12 months of actual 2017 data.

3.0 –VECC -17

Reference: Exhibit 3, pages 7 and 15

Preamble: At page 15 Energy+ indicates that a cogeneration facility began operation at the start of 2016. Table 3-3 (page 7) shows a drop in billed load in both 2016 and 2017.

a) If the 2017 data in Table 3-3 is not based entirely on actuals, please provide a revised table that is.
b) What were the kWh provided by the co-generation facility in each of 2016 and 2017?

3.0 –VECC -18
Reference: Exhibit 3, pages 14, 21 and 25
Load Forecast Model, Purchased Power Model Tab

a) At page 25 Energy+ indicates that it only has kW and not the kWh associated with the WMPs. However, in Column C of the Purchase Power Model, historical monthly kWh values are set out for the WMPs. Please reconcile.
b) Please clarify what is included in Column B of the Purchased Power Model Tab and the sources of the data used to derive the values.
c) Does Energy+ have any Fit or microFIT installations in its service area? If yes, please provide a schedule setting out the annual purchases for the period 2008-2017.
d) If the response to part (c) is yes, were these purchases included in the "total system purchased energy" for purposes of estimating the regression model (i.e., Column F of the Purchased Power Model Tab)?
e) If the FIT/micorFIT purchases were not included in the total system purchased energy please provide a revised load forecast (i.e. excel model similar to current filing) where the total of IESO plus FIT/microFIT purchases is used as the dependent variable.
f) Based on the formula used to determine Column F of the Purchased Power Model Tab it appears that the load associated with WMPs served by Energy+ is excluded from the Purchased Power actual data used. Please confirm if this is the case. If not please explain the derivation of Column F.

3.0 –VECC -19
Reference: Exhibit 3, page 15

Preamble: The regression model is set out at page 15 and the coefficient for CDM Activity is -0.30.

a) Please confirm that, based on Energy+'s proposed load forecast model, a 1 kWh increase in CDM activity will result in a 0.3 kWh decrease in purchased power.
b) Please explain how/why this result is considered to be intuitively correct. Wouldn't one intuitively expect the coefficient to be reasonably close to -1.0, recognizing that there would also be a need to allow for losses?
c) Did Energy+ test a load forecast model specification where the dependent variable was purchases plus CDM savings?
   i. If yes, please provide both the model results and the resulting forecast.
   ii. If no, please provide an alternative load forecast model that:

1) As the dependent variable, uses the Power Purchases (per the current model) – adjusted for FIT and micro/FIT purchases if required – but also adds to this value the monthly CDM activity values (adjusted by the annual loss factor for the year concerned).
2) As the independent explanatory variables, uses the same variables as the current model – excluding the CDM activity variable.

ii. If no, please provide a forecast of power purchases for 2019 by:
   - Using the model developed per part (ii) and the currently forecast values for the independent variables (excluding CDM activity) to obtain an initial forecast for 2018 and 2019.
   - Adjusting the total CDM activity results shown in Table 3-10 for 2018 and 2019 by the average historical loss factor (2.82% per page 18).
   - Adjust the initial forecasts for 2018 and 2019 by the total (loss adjusted) CDM activity values.

3.0 –VECC -20
Reference: Exhibit 3, page 18
Load Forecast Model, Purchased Power Model Tab

a) What exactly does the unemployment variable used in the regression analysis represent?
b) Please confirm that for the forecast years (2018 and 2019) Energy+ used the average unemployment for 2017 as the value for all months. If not confirmed, what was basis for the forecast values used for unemployment?
c) Is Energy+ aware of any forecasts of unemployment for 2019 for the Kitchener-Waterloo area (either levels or percentages)? If yes, please provide. If not, please provide any forecasts for 2019 Energy+ is aware for Ontario unemployment (either levels or percentages).

3.0 –VECC -21
Reference: Exhibit 3, page 16 (Table 3-10)

a) Please provide the reports (i.e., for CND and Brant County) from the OPA/IESO that support the 2006-2010 CDM results set out in Table 3-10.
b) Energy+ has provided a copy of the 2011-2014 CDM Persistence Report for Brant County (Excel File). However, a similar report for Cambridge North Dumfries does not appear to have been provided. Please provide.

c) Please explain how the 2017 Program values for 2017-2019 were derived from the Excel File – EnergyPlus_01_2018_Participation and Cost Report
d) Please confirm that 2017 Final Verified CDM Results Report for Energy+ is now available from the IESO and provide a copy.
e) Based on the 2017 Final Verified CDM Results Report:
    i. Are any revisions required to Table 3-10?
    ii. If yes, please provide a revised version.
    iii. If yes, please provide a revised Load Forecast.
    iv. If yes, please provide revised LRAMVA values (i.e., Table 3-24)

3.0 –VECC -22
Reference: Exhibit 3, pages 19-21
Load Forecast Model, Rate Class Customer Model Tab

a) Do the customer counts set out in Table 3-13 and used in the derivation of the values in Tables 3-14 to 3-16 include the WMPs?
b) Do the kWh values by customer class used to determine the 2017 actual average usage per customer (Table 3-16) include the usage of the WMPs.
c) If both the customer counts and usage values do not exclude the WMPs, please provide revised tables that do and a revised load forecast.

3.0 –VECC -23
Reference: Exhibit 3, pages 22-23
Exhibit 7, page 10

d) Please provide copy of the 2015-2020 CDM Plan for Energy referenced on page 22. Please confirm that this is the most recent CDM Plan approved by the IESO and, if not, provide the most current approved Plan.
e) Is the new load displacement generation referenced at Exhibit 3, page 22 (lines 15-17), the same facility as discussed in Exhibit 7 (page 10) and for which a "cogeneration facility flag" was included in the Purchased Power Model?
    i. If no, when is this additional load displacement generation expected to go into service and is this "load displacement generation" contributing to Energy+'s 2015-2020 CDM Plan?
    ii. If yes, please confirm that by using a "cogeneration facility flag" in the purchased power model and the average use in 2017 to determine class loads, the Application has already accounted for the load reduction associated with the load displacement generation.

iii. If yes, is any portion of the CDM savings set out in Table 3-10 for 2016 and 2017 programs attributable to this load displacement generation? If so, why were these "savings" included in the CDM Activity variable when the impact of the load displacement generation is already accounted for by the "cogeneration facility flag"? Please revise the load forecast model to remove the double counting.

iv. If yes, please explain why the 2018 CDM values have not also been adjusted to remove the impact of the load displacement generation?

f) What was the kWh adjustment for load displacement generation that was included in Table 3-20 (per page 22, lines 15-17)? What would be the associated impact on annual billing demand?

3.0 –VECC -24
Reference: Exhibit 3, pages 23-24

a) Please confirm that the LRAMVA values set out in Table 3-24 exclude the savings from the load displacement generation discussed on page 22 (lines 15-17). If not confirmed, please explain why.
b) If Energy+ 2018 actual savings from 2018 or 2019 CDM programs include savings due to new load displacement generation in those years (i.e., in addition to the existing 2016 load displacement generation), does Energy+ expect that such savings will be included in the verified results reported by the IESO for those years? If not, why not?
c) If yes, why shouldn't these savings also be included in the LRAMVA threshold values for the relevant year(s)?
d) If yes, what are the expected annual kWh savings and associated impact on annual billing demand?
e) Please confirm that the energy forecast by customer class excludes: i) the customer load supplied by load displacement generation and ii) the energy use by WMPs. If either point is not confirmed, please explain (with reference to the Load Forecast model) how the relevant energy values have been included in the customer class values.

3.0 –VECC -25
Reference: Exhibit 3, pages 25-27
Load Forecast Model, Rate Class Load Model Tab

a) Does the kW forecast in Table 3-30 include the kW that will be subject to the proposed Standby Charge? If yes, please indicate the values included for each customer class for 2019 and how they were determined.

b) With reference to the Rate Class Load Model Tab, please explain the reason for the 50,379.33 kW adjustment to the 2019 Large Use billing demand forecast. How was the 50,379.33 kW value determined?

3.0 –VECC -26
Reference: Exhibit 3, page42 (Table 3-45)

a) Please provide the 2017 actual Other Operating Revenue broken down per Table 3-45.

3.0 –VECC -27
Reference: Exhibit 3, pages 42-43 (Table 3-45) and 53
Exhibit 8, page 21

a) Please explain the reduction in revenues as between 2016 actual and 2019 forecast for: i) Late Payment Charges, ii) Change of Occupancy Charges, and iii) Document Charges.
b) Please explain the significant drop after 2015 in revenues from Collection/Reconnection charges.
c) At Exhibit 3, page 53 the Application states that the Specific Charge for Access Power Poles has been increased and the increase ($22.35 to $43.63) is shown in Exhibit 8. However, there is not a similar increase in Pole Rental revenues for 2019. Please reconcile.

EXHIBIT 4 – OM&A

4-VECC-28
Reference: E1/pg. 47

a) E+ variously describes the incremental costs of monthly billing and OEB costs in 2019 as 496k (Figure 1, pg. 47) or 487k (390+97 table 1-18, pg. 49). Please clarify.

4-VECC-29
Reference: E1/pg.50

a) Please explain why the average increase for management/executive salaries for the 2014-2019 period (23%) far exceeds the rate of inflation for the same period.

b) Please explain why management/executive total compensation for that same period also significantly exceeds the non-management increase of the 5 year period (i.e. 21.1% vs 9.8%).

4-VECC-30
Reference: E1/pg. 141

a) Please explain how (if) the desired outcomes of the metrics listed in Table 1-10A are related to executive and other employee compensation.

4-VECC-31
Reference: E1/pg. 146

a) Please update E+'s Scorecared to include 2017 actual results.
b) Why in the provided Scorecard was E+ forecasting a significant decline in its future reliability performance?

4-VECC-32
Reference: E1/pg. 249 & Appendix 2-K

a) Please explain why in the 2018-19 Business Plan it lists salaries and benefits expenditures of $10.6M whereas in Appendix 2-K the amount listed is $15.3 (rounded).

4.0-VECC-33
Reference: Exhibit 4, pg.29

a) Please explain how the incremental customer care clerk and billing clerk are directly associated with the move to monthly billing.
b) Please explain how monthly billing causes "incremental collection notices" and how "processing of increased payments" is related to the move to monthly billing.

4.0-VECC-34
Reference: Exhibit 4, pg.30

a) What incentives does Energy+ offer its customers to switch to e-billing or if they pay through on-line banking?

4.0-VECC-35
Reference: Exhibit 4, pg. 32

a) We are unclear how as to why and how there is an <u>increase</u> in operating cost with the potential sharing of services with Brantford Power (BPI). The evidence states:

The increase in operating costs of $195,000 is comprised of the following:

	Annual Cost
Shared Space Operating Lease Estimate	$255,000
Shared Mechanic (1/2 FTE)	40,000
Operating Costs (Exclusive Space)	35,000
	$330,000
Less: Current Operating Costs (Existing Facility)	(135,000)
Total Operating Costs	$195,000

i) Why does the sharing of the mechanic with BPI who is employed by Energy+ result in an increase in cost?
ii) Why is Energy+ leasing space for $255k to replace space that cost 135k?

4.0-VECC-36
Reference: Exhibit 4, pgs. 32-34, 42

a) What was the forecast annual operating cost of the System Control Room provided to the Board in EB-2013-0116?
b) What are the current forecast annual operating costs for this in 2018?

4.0-VECC-37
Reference: Exhibit 4, pg.49

a) Please amend Table 4-17 to add a row showing the annual yearly inflation rate (CPI) for each year 2014 through 2018 (to-date).

4.0-VECC-38
Reference: Exhibit 4, pg. 56, Appendix 2-K

a) Please amend Appendix 2-K to add a row showing the total compensation capitalized in each year.

4.0-VECC-39
Reference: Exhibit 4, pg.74

a) Please provide the EDA fees (actual and forecast) on a combined basis for the years 2014 through 2019.

4.0-VECC-40
Reference: Exhibit 4, pg. 82

a) Please provide (separately) the legal costs, consultant costs incurred to date for this application.
b) Please describe the incremental staff costs of $107,538 allocated to this application. Specifically address what costs were incurred to replace staff resources allocated to this application.
c) Please breakdown by consultant the $347,861 in consulting costs incurred on this application. Please show the actual costs incurred to date for each consultant.

4.0 -VECC -41
Reference: Exhibit 4, page 111 (lines 7-13)
http://www.ieso.ca/en/sector-participants/conservation-delivery-and-tools/conservation-targets-and-results

a) The 2017 Verified CDM Results Reports have been released by the IESO. Please update the LRAMVA Workforms and provide a revised version of Table 4-57.

EXHIBIT 5 – COST OF CAPITAL

5-VECC-42
Reference: Exhibit 5, page 6

a) Please recalculate the long-term debt rate on the assumption that the notional portion of the debt attracts the Board's affiliate debt interest rate.
b) Since the $7.8M is notional debt please explain why it would not be appropriate to use either the Board's default affiliate rate or the lowest long-term borrowing rate of the Utility (i.e. 3.97%) to calculate the amount of deemed interest costs to be recovered related to notional debt?

5-VECC-43

Reference: Exhibit 5, page 7

a) If the net result of Energy+'s loan of $3,665,000 with its affiliate is zero because an equal amount of interest is earned as is paid on this debt what purpose does this borrowing serve and what benefit does Energy+ receive on this transaction?

EXHIBIT 6 – REVENUE REQUIREMENT

n/a

EXHIBIT 7 – COST ALLOCATION

7.0 – VECC –44
Reference: Exhibit 7, page 6

a) Were there no assets associated with Services recorded for the CND service area because: i) all customers pay for their service connections or ii) the costs incurred by CND were recorded in another account?
b) Why are only Residential, GS<50, GS 50-999 and GS 1000-4999 given weighting factors for Services?
c) What were the Service weighting factors used by BCP in its last cost of service application? Would it not be more appropriate to use these?
d) Do any of Energy+ Residential or GS customers have more than one service connection? If yes, how many customers and what are the number of associated service connections?

7.0 – VECC –45
Reference: Exhibit 7, page 6

a) What was the basis for the Billing and Collecting weighting factors used in the former CND's 2014 cost of service application (e.g., were they based on an analysis of CND's billing and collecting activities)?

7.0 – VECC –46
Reference: Exhibit 7, page 7 / Cost Allocation Model, Tab I7.1 – Meter Capital

a) Please explain why there is no meter/meter capital attributed to the Embedded Distributor-Waterloo North Hydro.

7.0 – VECC –47

Reference: Exhibit 7, pages 8-9 / Appendix 2-Q

a) For each of the Embedded Distributor customer classes, please describe the supply arrangements in terms of what facilities owned by Energy+ are used to supply the customer(s) and how these facilities connect to HONI's transmission system.

b) Please provide the derivation of the 12% Administrative Burden used in Appendix 2-Q

.c) For each Embedded Distributor customer class, how was the "Total annual OM&A costs of asset class providing LV services" determined as input in Appendix 2-Q and why is the value the same for all classes?

d) Why, in Appendix 2-Q, is the Original Asset Cost, Accumulated Depreciation and Annual Depreciation for Low Voltage Lines the same for all Embedded Distributor classes?

7.0 – VECC –48

Reference: Exhibit 7, pages 5 and 10-15 /Cost Allocation Model, Tabs I6.1 and I8

Preamble: On page 5, .Energy+ sets out the 2019 forecast kWh by customer class and the resulting Load Profile Scaling percentages used in the Cost Allocation. On page 10, Energy+ states that it has reflected a monthly peak of 28.8 MW for the Large Use customer with load displacement generation in the cost allocation model and rate design process.

a) For 2019, what is the impact of the adjustment for load displacement generation on the billing demand for the Large Use class, i.e., the difference between the load displacement generation customer's forecast annual billing demand and 345.6 MW (12x28.8 MW)?

b) In Exhibit 3, the forecast 2019 billing kW for the Large Use class is 382,038 kW and the same value is used in Tab I6.1. Does this value include the adjustment for load displacement generation?

i. If yes, please show where/how in Exhibit 3 the kW forecast for the Large Use class is adjusted to account for the difference between the billed kW forecast for the load displacement customer and 28.8 MW / month.

ii. If no, what revisions are required to Tab I6.1

c) It is noted that the Load Profile Scaling factor for the Large Use class is based on a 2019 forecast of 145.5 GWh, which is the same value as forecast in Exhibit 3.

How were the Large Use class load profiles set out in Tab I8 specifically adjusted to reflect a 28.8 MW monthly peak for the Large Use customer with load displacement generation?

7.0 – VECC –49

Reference: Exhibit 7, page 5 / Exhibit 3, pages 25-26 and page 28 / Cost Allocation Model, Tabs I6.1 and I8

Preamble: It is noted that in Exhibit 3, page 26 the 2019 forecast energy for the GS 50-999 and GS 1000-4999 classes is 493.1 GWh and 231.0 GWh respectively and that these same values are used in Tab I6.1 of the Cost Allocation Model. However, in the case of the 2019 forecast billing demand for these classes the values are different. It is noted that the energy values referenced above are used to determine the Load Profile Scaling Percentages for the GS 50-999 and GS 1000-4999 classes.

a) Is the difference between the billing demands for the GS 50-999 and GS 1000-4999 classes per Exhibit 3 versus the Cost Allocation model due to the fact the latter includes the billing demands for the WMPs in these classes? If not, what is the basis for the difference and where are the billing demands for the WMPs accounted for in Tab I6.1?

b) Please confirm that the energy values referenced in the Preamble for the GS 50-999 and GS 1000-4999 classes do not include the WMPs in those classes.

i. If not confirmed, please indicate where/how in the Load Forecasts model the energy related to the WMPs has been included in the values for these classes.

ii. If confirmed, please explain how the load associated with the WMPs in the GS 50-999 and GS 1000-4999 classes have been incorporated into the load profiles set out in Tab I8 of the cost allocation model.

7.0 – VECC –50

Reference: Exhibit 7, page 18

a) Please explain why for each of the Embedded Distributor Customer classes the revenue to cost ratio has been decreased/increased such the proposed value is 100% as opposed to the max//min value for the OEB’s policy range.

8.0 RATE DESIGN (EXHIBIT 8)

8.0 –VECC - 51
Reference: Exhibit 8, page 5

a) Do the billing kWs used in the calculation of the fixed-variable split for the Large Use class include an adjustment to include the load that will be subject to a Standby Charge in 2019?
b) What is Energy+'s view as to whether the class' fixed/variable split percentage should or should not be calculated including the Standby load and why?

8.0 –VECC - 52
Reference: Exhibit 8, pages 7-8 / RRWF, Tab 12

a) What is the basis for the "current rates" set out in Tab 12 of the RRWF (i.e., fixed charge - $21.81 / variable charge - $0.0047/kWh)?

8.0 –VECC - 53
Reference: Exhibit 8, pages 13-14

a) What wording is Energy+ proposing for purposes of describing how the monthly billing demand (kW) that the standby charge will apply to will be determined?
b) It is noted that for purposes of the RTSRs, Energy+ is proposing that the billing determinant for the Large User with load displacement generation be based on gross load (i.e., maximum coincident value of metered billing demand plus metered load displacement generation output). Please explain why the standby charge isn't also applied on the difference between the monthly peak gross load and the monthly peak delivered load.

c) Will the Standby Charge apply in all instances where a customer has load displacement generation or will it only apply in instances where the generation exceeds a certain capacity limit? If the latter, what are the proposed limits?
d) Please provide the proposed changes/additions to Energy+'s Conditions of Service as a result of implementing the Standby Charge.

8.0 –VECC - 54
Reference: Exhibit 8, pages 16-19 / RTSR Workforms

a) With respect to the BCP RTSR Workform – Tab 4 (RRR Data), please confirm that the 1.287 loss factor used for some of rate classes is correct. If so, please explain why it is so high. If not, please provide revised RTSR calculations

.b) With respect to the RTSR Harm Workform, please explain how the load forecast was split between the BCP and CND service areas.

c) With respect to the RTSR Harm Workform:

i. For those classes billed on a kWh basis, please indicate the basis for the loss factors used to convert the load forecast per Exhibit 3 to the values shown in Table 8-9.

ii. For those classes billed on a kW basis, please reconcile the total kW value shown in Table 8-9 with those in the load forecast in Exhibit 3.

iii. The Application (page 16, lines 28-31) indicates that the Large Use customer with load displacement generation will be billed on a gross load basis. However, the 2019 kW value used in the RTSR determination appears to be the same as that the load forecast per Exhibit 3 (382,032 kW. Please reconcile.

8.0 –VECC - 55
Reference: Exhibit 8, pages 22-23

a) How much did Energy+ pay HONI in 2017 for LV service (i.e., ST charges)?

b) Does HONI bill ST rates on a gross load basis, similar to the way the IESO bills for wholesale transmission services? If yes, will the LV billing demand determinant also be based on the gross load methodology?

8.0 –VECC - 56
Reference: Exhibit 8, page 24

a) Please provide the basis for the 1.0045 Supply Facilities Loss Factor and demonstrate that it accounts for both: i) the fact that Energy+ is partially an embedded utility and iii) the existence of FIT and/or microFIT generation in Energy+'s service area.

8.0 –VECC - 57
Reference: Exhibit 8, page 30

a) What would be the resulting Residential rates for 2019 if the transition to the fully fixed charge was extended one year (i.e., to 2020)?
b) What would be the resulting total 2019 bill impact for a low use Residential customer if the transition was extended one year?

8.0 –VECC - 58
Reference: Exhibit 8, pages 84 and 97

a) Why is it necessary to have separate Rate Schedules for Residential customers in the former CND service area vs. the former Brant service area for 2019?

EXHIBIT 9 - DVAS

VECC-59
Reference: Exhibit 9, Section 9.2

Preamble: IFRS related accounts 1575 and 1576 are calculated based on accounting changes beginning in 2013 (1576) or 2014 (1575). However, Brant County Power amalgamation was only effect January 1, 2016 (Exhibit 1, pg.12).

a) Given the timing of the Utilities' amalgamation why would it not be more appropriate to calculate and dispose of the balances of these accounts in proportion to the pre- and post-2016 impacts?
b) If this were to be done would there be a material difference in the amounts owing to or from the customers in the respective BCP and CND service territories?

VECC-60
Reference: Exhibit 9, pages 5-

a) Is a separate rate rider calculated for former CND and BCP service customers to collect their respective 1555 account balances?

End of Document