APPENDIX E

Exhibit 2 – Rate Base

OEB Staff - Settlement Proposal - Clarification Question 1

Ref: 2-Staff-12, 2-Staff-15, 1-Staff-10

a) Please specify the changes Energy+ made to App.2-AB, Capital Expenditures, following the proposed changes of in-service date for each of the Southworks facility, Garden Avenue facilities and Bishop St. renovation:[1]

   i. For 2019 test year and 2020 related to Garden Avenue Facility.
   ii. For 2020, 2021 (if applicable) and 2022 related to Southworks Facility.
   iii. For 2022 related to Bishop St. renovation.

RESPONSE

The table below provides a summary of the changes made to the General Plant category by Energy+ to Appendix 2-AB Capital Expenditures for the 2019 test year, and 2020, and 2022 for the proposed changes to the in-service dates for the Southworks facility, Garden Avenue facilities and the Bishop St. renovations:

$000's

Changes Made to General Plant:	**2019**	**2020**	**2021**	**2022**	**2023**
Move Shared Facilities with BPI expenditures to 2020 Move **Southworks** expenditures to 2022 Remove Bishop St. renovations from the five year forecast	(4,400)	4,400 (5,000)		5,000 (2,000)	
	(4,400)	(600)	-	3,000	-

Energy+ notes that there was an error in the amount reported in the 2020 year in the Appendix 2-AB filed with the IR Responses. The general plant amount in 2020 was incorrectly reported as $5,656, however, the amount should have been $5,556.

Please refer to response to follow up Question #1 with respect to the revised estimate for the Southworks facility of $8.1MM.

[1] 2-Staff-12 f and 2-staff-15 f

Energy+ has provided a revised Appendix 2AB Capital Expenditures attached to this question as Appendix 2-1.

The following is a reconciliation of the Appendix 2AB as filed compared to the Appendix 2AB as amended and included in this response.

CATEGORY	As Revised - Appendix 2B - Follow Up Questions					As Filed - Chapter 2 Appendices Schedule 2AB					Changes through IR Process				
	Forecast Period (planned)					Forecast Period (planned)									
	2019	2020	2021	2022	2023	2019	2020	2021	2022	2023	2019	2020	2021	2022	2023
	$ '000					$ '000									
System Access	4,524	4,007	4,352	3,934	4,129	4,524	4,007	4,352	3,934	4,129	-	-	-	-	-
System Renewal	6,653	8,591	8,007	8,849	8,672	6,653	8,591	8,007	8,849	8,672	-	-	-	-	-
System Service	367	591	954	422	422	367	591	954	422	422	-	-	-	-	-
General Plant	943	5,556	1,668	6,538	1,765	5,343	6,156	1,668	3,538	1,765	(4,400)	(600)	-	3,000	-
Deferred Revenue (Capital Contributions)	(817)	(769)	(886)	(772)	(782)	(817)	(769)	(886)	(772)	(782)	-	-	-	-	-
TOTAL EXPENDITURE	11,670	17,976	14,095	18,971	14,206	16,070	18,576	14,095	15,971	14,206	(4,400)	(600)	-	3,000	-
System O&M	$ 5,931	$ 5,976	$ 6,022	$ 6,069	$ 6,116	$ 5,931	$ 5,976	$ 6,022	$ 6,069	$ 6,116	-	-	-	-	-

OEB Staff - Settlement Proposal - Clarification Question 1

b) Please discuss why there is no change made to the System O&M in App.2-AB after changing the in-service dates of proposed facilities.

RESPONSE

Energy+ did not make any changes to the System O&M in Appendix 2-AB Capital Expenditures after changing the in-service dates of the proposed facilities. The lease costs for the shared facilities were originally included in Office and Building costs, which were included in the Administrative portion of OM&A. The removal of these costs reduced the Administrative expenditures in Appendix 2JA, Appendix 2JB, and Appendix 2JC, however, this change would not have resulted in a change to Appendix 2-AB System O&M.

OEB Staff - Settlement Proposal - Clarification Question 1

c) Please specify the reduction of depreciation expense for 2019 test year related to the removal of Garden Avenue facility.

RESPONSE

The impact of removing the $4,400,000 in capital costs related to the Garden Avenue facility in the 2019 Test Year was a reduction in depreciation expense of $36,667. Energy+ used a 60 year life for amortization and applied the $^1/_2$ year rule in the 2019 Test Year.

OEB Staff - Settlement Proposal - Clarification Question 1

d) Please specify the change in depreciation expense for 2019 test year related to updating 2017 amounts to actuals.

RESPONSE

As provided in the 2019 EnergyPlus_Rev_Reqt_Workform_1 Staff 2.xlsm file, at Tab 14 Tracking Sheet, Reference 1 Update for 2017 Actuals, the depreciation expense for the 2019 Test Year was reduced by $242,683 as a result of updating the 2017 fixed assets to actuals.

OEB Staff - Settlement Proposal - Clarification Question 1

e) Please clarify whether or not Energy+ has updated App. 2-BA Fixed Asset Continuity Schedule for 2018 bridge year using 2018 year to date actuals.

RESPONSE

Energy+ did not update Appendix 2-BA Fixed Asset Continuity Schedule for the 2018 bridge year using 2018 year-to-date actuals. The 2018 Bridge Year Appendix 2-BA Fixed Asset Continuity Schedule was updated to reflect the following changes:

- Updated the Opening Costs and Opening Accumulated Depreciation as a result of updating the 2017 Actuals.
- Updated the 2018 depreciation expense to reflect changes to the 2018 depreciation expense as a result of updating the 2017 Actuals (i.e. depreciation changes to reflect the differences in additions in 2017 based on Actuals).

The additions and disposals for the 2018 Bridge Year were not revised using year-to-date actuals as the 2018 fixed asset continuity schedule is intended to reflect the expected additions and disposals for a full year, not a partial year.

OEB Staff - Settlement Proposal - Clarification Question 1

f) Please explain why capital expenditure on system service for 2017 was 95.6% (App.2-AB) lower than the plan.

RESPONSE

Actual System Service expenditures for 2017 were $87,000, compared to the Plan of $1,984,000. As explained in Exhibit 2, Page 69 of 1497, the variance in System Service expenditures for 2017 compared to plan was principally explained by the deferral of the investment in land and engineering studies for a new transformer station (MTS#2) which was deferred and planned for 2018.

APPENDIX 2-1 - AMENDED APPENDIX 2AB – CAPITAL EXPENDITURES

Appendix 2-AB

Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements

Consolidated Former CND and BCP (2014-2015) and Energy+ Inc. (2016-2023)

First year of Forecast Period: *2019*

CATEGORY	Historical Period (previous plan[1] & actual)															Forecast Period (planned)				
	2014			2015			2016			2017			2018			2019	2020	2021	2022	2023
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Forecast	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%			$ '000		
System Access	9,038	3,781	(58.2%)	11,749	8,064	(31.4%)	4,355	5,486	26.0%	4,867	5,599	15.0%	5,423	5,423	0.0%	4,524	4,007	4,352	3,934	4,129
System Renewal	5,921	4,361	(26.3%)	5,925	6,069	2.4%	6,700	8,193	22.3%	9,064	9,470	4.5%	5,819	5,819	0.0%	6,653	8,591	8,007	8,849	8,672
System Service	862	581	(32.6%)	745	1,399	87.8%	840	718	(14.5%)	1,984	87	(95.6%)	2,531	2,531	0.0%	367	591	954	422	422
General Plant	4,306	3,037	(29.5%)	2,476	2,337	(5.6%)	2,182	1,786	(18.1%)	3,016	2,413	(20.0%)	1,880	1,880	0.0%	943	5,556	1,668	6,538	1,765
Deferred Revenue (Capital Contributions)	(2,436)	(756)	(69.0%)	(4,082)	(4,496)	10.1%	(1,279)	(2,763)	116.0%	(1,429)	(3,212)	124.8%	(2,133)	(2,133)	0.0%	(817)	(769)	(886)	(772)	(782)
TOTAL EXPENDITURE	17,691	11,004	(37.8%)	16,813	13,373	(20.5%)	12,798	13,420	4.9%	17,502	14,357	(18.0%)	13,520	13,520	0.0%	11,670	17,976	14,095	18,971	14,206
System O&M	$ 5,805	$ 5,857	0.9%	$ 6,136	$ 5,636	(8.1%)	5,721	5,606	(2.0%)	$ 5,661	$ 5,747	1.5%	$ 5,915	$ 5,915	0.0%	$ 5,931	$ 5,976	$ 6,022	$ 6,069	$ 6,116
Total Net Expenditures		$ 11,004			$ 13,373			$ 13,420			$ 14,357			$ 13,520		$ 11,670				
Change in Work in Progress		(806)			(2,156)			(72)			1,284			-		-				
Assets Not In Use														(2,026)						
Asset Transfer on FA Continuity Schedule - Not an Addition		631																		
Total Net Expenditures, as per Fixed Asset Continuity Schedules		10,829			11,217			13,348			15,641			11,494		11,670				

Notes to the Table:

1. Historical "previous plan" data is not required unless a plan has previously been filed. However, use the last Board-approved, at least on a Total (Capital) Expenditure basis for the last cost of service rebasing year, and the applicant should include their planned budget in each subsequent historical year up to and including the Bridge Year.

2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year | 12

OEB Staff - Settlement Proposal - Clarification Question 2

Ref: 3-Staff-54; Exhibit 3, page 6

Energy+ stated that “The new load displacement generation has been taken out of the load forecast since the loss of distribution revenue associated with the new load displacement generation will be collected with the proposed standby charge”. OEB staff notes that the same adjustment has been made to the LRAMVA target.

Energy+ stated that “This program is associated with savings from new load displacement generation anticipated in 2018.” In reference to the regression model, Energy+ also stated that “the variable named Co-generation Facility Flag has been 13 added to reflect the impact of new co-generation facilities added in 2016.”

a) Please confirm that Energy+ will not seek to recover through an LRAMVA rate rider any future IESO verified savings for which a standby charge could be applied.

b) Please confirm that the “new load displacement generation anticipated in 2018” is actually savings which have already been occurring since 2016 at the co-generation facility added in that year. Otherwise, please explain and differentiate the projects:

RESPONSE

a) Energy+ confirms it will not seek to recover through an LRAMVA rate rider any future IESO verified savings for which a standby charge could be applied.

b) The “new load displacement generation anticipated in 2018” are additional load displacement generation projects that are anticipated to start in 2018 as part of the 2018 Process and Systems Upgrades Program outlined in the current Energy+ 2015 to 2020 CDM plan.

OEB Staff - Settlement Proposal - Clarification Question 3

Ref: Response to 9-Staff-96

a) Please confirm that the DVA balances and transactions for 2017 were actually compiled by service territory and not on a consolidated basis.

RESPONSE

Energy+ confirms that the DVA balances and transactions for 2017 were compiled by service territory and then consolidated.

OEB Staff - Settlement Proposal - Clarification Question 3

Ref: Response to 9-Staff-96

b) Please confirm that the IESO invoice has yet to be harmonized, and had not been harmonized when the 2017 balances were compiled.

RESPONSE

Energy+ confirms that the IESO invoice has not been harmonized, and was not harmonized when the 2017 balances were complied.

OEB Staff - Settlement Proposal - Clarification Question 4

Ref: Response to 9-Staff-97

a) Please confirm that the Applicant settles with the IESO on the 4th day of the following month (i.e. December consumption is settled on January 4th and so on), and not on a one month lag (i.e. December consumption is settled on February 4th and so on).

RESPONSE

Energy+ confirms that it settles with the IESO on the 4th day of the following month, and not on a one month lag.

OEB Staff - Settlement Proposal - Clarification Question 4

Ref: Response to 9-Staff-97

b) The Applicant completed its responses to Appendix A of the GA Analysis Workform Instructions. Based on the responses provided, please confirm the following (since the responses are the same for both service territories, OEB staff will assume that the responses provided relate to both service territories, if different, please indicate):

i. In the response provided for 2a, please confirm that the Applicant is indicating that its monthly RPP settlement with the IESO is based on actual consumption for the month being settled. Please also confirm that the Applicant's systems have the capability to produce such consumption data, including consumption that is yet to be billed for the month being settled, by the 4th day of the following month. Please further confirm that the only estimate that is used in the Applicant's monthly RPP IESO settlement is the GA rate (2nd estimate).

ii. In the response provided to 2f), please explain why the CT1142 true-up adjustment impacts both accounts 1588 and 1589 when CT 1142 is only recorded to account 1588 (as indicated in the Applicant's response to Question 1 of Appendix A).

iii. In the response provided to Question 3a, please confirm that the Applicant waits for the actual CT 148 invoice to come in before it books anything to its G/L. and that no estimate of the GA charge is initially recorded for which a true-up is then recorded once the actual invoice comes in.

iv. In the response to 3d, the Applicant has indicated that no true-up related to the recording of CT 148 is required because the invoice is split based on actual consumption at the time the invoice is received. However in response e) the Applicant has indicated that the month of December 2017 was trued up in 2018, please explain what true-up is being referred to here.

v. What is being trued up in g) if the split was already done based on actual? Please explain, as noted above.

vi. In the response to question 4, the applicant provided a summary of the reversal required in the 2017 DVA continuity schedule related to principal adjustments that were recorded in 2015 and 2016

1. For Brant County, as part of the last IRM application the applicant recorded principal adjustments to accounts 1588 and 1589 as follows

	1588	**1589**
2015	$607,478	($607,478)
2016	($333,169)	$333,169
Total	$274,309	($274,309

Note that the $1,133,153 that was recorded as a principal adjustment to account 1589 in 2015 is ignored for purposes of this analysis and it was recorded in order to reverse out the impact of the principal adjustment that was recorded for 2014.

Please provide the period in which each of the above principal adjustments were actually recorded in the utility's G/L and please provide further rationale as to why the Applicant believes that they do not need to be reversed in the 2017 DVA continuity schedule and GA Analysis Wokform.

2. For the CND service territory, the Applicant had recorded the following principal adjustments for 2015 and 2016:

Account 1588:

DVA Continuity Schedule Adjustment (COP 1589) - Energy+ (CND)	EB-2017-0030 (IRM Application)		
	2015	2016	Total
Adjust unbilled to actual revenue differences	$ 13,986		$ 13,986
RPP/Non-RPP Allocation Adjustment (GL Entry)	$ 2,675,144	$ 636,201	$ 3,311,345
Total Adjustments Reported in DVA Continuity Schedule	**$ 2,689,130**	**$ 636,201**	**$ 3,325,331**

Account 1589:

DVA Continuity Schedule Adjustment (GA 1589) - Energy+ (CND)	EB-2017-0030 (IRM Application)		
	2015	2016	Total
Remove prior year end unbilled to actual revenue differences		(14,906)	(14,906)
Add current year end unbilled to actual revenue differences	209,336		209,336
IESO Overbilling - Class A timing differences	754,002	(158,185)	595,817
	$ 963,338	**$ (173,091)**	**$ 790,246**
RPP/Non-RPP Allocation Adjustment (GL Entry)	(2,675,144)	(636,201)	(3,311,345)
Total Adjustments Reported in DVA Continuity Schedule	**$ (1,711,806)**	**$ (809,292)**	**$ (2,521,098)**

It is not clear why the Applicant has excluded the adjustments for $2,675K and $636K from the principal adjustment reversals that it has proposed in the 2017 continuity schedule. Please explain rationale for excluding them and please provide the period in which the Applicant actually recorded these amounts to their G/L?

RESPONSE

i. Energy+'s monthly RPP settlement with the IESO is based on actual consumption for the most recent billing period. Energy+'s systems do not have the capability to produce consumption data that is yet to be billed for the month being settled. Energy+ does not bill RPP customers on a calendar month basis. This creates a lag in the settlement process for the unbilled portion of consumption during the month.

In order for Energy+ to settle and report on the actual GA rate, Energy+ takes the billed consumption from the meter read date, and pro-rates the billed consumption to the appropriate month using billing statistics data. For example, if a meter is read mid-month a portion of the consumption would be attributable to the current month and the remainder to the prior month. Energy+ applies the actual GA rate against the prior month's consumption when it is available and utilizes the IESO 2nd estimate to any consumption that falls within the current month.

Any settlements that were based on the 2nd estimate will be subject to a true-up to the actual rate in the subsequent month. As a result of the lag in the settlement process a true-up on consumption is not required.

ii. The following table provides the impact of the December 2017 GA rate true up (2nd estimate vs actual). These amounts have not been recorded in the general ledger in 2017.

CND	Brant	Total
$11,460,06	$1,193.25	$12,653.31

iii. Energy+ confirms that it does not record an estimate of the CT 148 invoice prior to receipt. There is no accrual, estimate or true-up recorded.

iv. Energy+ prepares a true-up to the actual RPP and Non RPP allocation percentages for all months at year end.

In January 2018, Energy+ posted the true-up entry to the December 2017 G/L which resulted in a debit of $818,770 to accounts 1588 and 4705 with an offsetting credit to accounts 1589 and 4707.

v. The RPP and Non RPP allocation entries are based on estimate percentages until the final GA rates are known.

vi. Energy+ has updated the DVA Continuity Schedules and GA Analysis Workforms to capture the adjusting entries made to accounts 1588 and 1589 as transactions in 2017. These entries have been reversed in the principal adjustments column since these were prior period adjustments and have already been reflected in the 2017 opening balances.

OEB Staff - Settlement Proposal - Clarification Question 4

Ref: Response to 9-Staff-97

c) The Applicant provided revised GA Analysis Workforms by service territory:

i. Has the Applicant reconciled the difference identified in the Brant County's GA Analysis Workform. If so, please provide the updated GA Analysis workform.

ii. In the CND GA Analysis Workform, why hasn't the Applicant factored in the reversal of the principal adjustments it has proposed in the DVA continuity schedule as part of its analysis in Note 5? Wouldn't those amounts be captured by the transactions during 2017? Please explain and update the GA Analysis workform as needed.

RESPONSE

c)

i. Energy+ has reconciled the difference identified in Brant County's GA Analysis workform. The revised GA Analysis workform files have been provided in Excel format with the following file names:

2019 Energy+ GA-Analysis-Workform - BCP - Settlement.xlsb
2019 Energy+ GA-Analysis-Workform - CND - Settlement.xlsb
2019 Energy+ GA-Analysis-Workform - Consolidated - Settlement.xlsb

The reconciling item was caused by the inclusion of embedded generation balances from Hydro One in account 4705 during the calculation of a year-end true-up of the RPP and Non RPP allocation. The calculation should only have included balances from the IESO, as the balances from Hydro One are fully allocated to Non RPP as they are classified as GS>1000.

The resulting impact was an adjustment of $640,180 between 1588 and 1589, which have been included as principal adjustments on the revised DVA Continuity Schedules.

ii. Energy+ has revised the CND GA Analysis Workform to include the reversal of the principal adjustments in Note 5. The revised adjusted net change in principal balance accurately captures 2017 activity in the account.

OEB Staff - Settlement Proposal - Clarification Question 4

Ref: Response to 9-Staff-97

d) In response to 9-Staff-97 d) ii, it is not clear to OEB Staff why the allocation adjustment that the Applicant is referring to in this response has now been removed. What has changed to necessitate the removal of this allocation adjustment between accounts 1588 and 1589?

RESPONSE

The GA Analysis Workform submitted on Apr 30, 2018 incorrectly categorized ($818,770) under Note 2b “current year end unbilled to actual revenue differences“.

This amount is related to the 2017 year end true-up for the RPP and Non RPP allocation and was recorded in the G/L in 2017. As a result, this amount is considered as part of the 2017 transactions and is not a reconciling item in the GA Analysis Workform.

OEB Staff - Settlement Proposal - Clarification Question 4

Ref: Response to 9-Staff-97

e) In response to 9-Staff-97 e), the Applicant has submitted that the $1.2 million claimed for disposition in account 1588 represents the difference between RPP revenue and the cost of power attributed to RPP customers. If that is the case, then shouldn't this amount be settled with the IESO and not with ratepayers? Is there a settlement with the IESO for 2017 that has not been recorded against this account balance?

RESPONSE

As a result of the adjustment noted in 11 c i) the principal amount claimed for disposition in account 1588 is $579,545.

OEB Staff - Settlement Proposal - Clarification Question 5

Ref: Response to 9-Staff-100

In this response the Applicant responds to question related to account 1595.

a) The applicant has indicated that it is the first time 1595 (2016) has been brought forward for disposition, however did not confirm the same for 1595 (2014) and 1595 (2015). Please confirm that the residual balances in these accounts already have been disposed once.

RESPONSE

Energy+ confirms the residual balances in accounts 1595 (2014) and 1595 (2015) have already have been disposed through the 2018 IRM Application (EB-2017-0030).

OEB Staff - Settlement Proposal - Clarification Question 5

Ref: Response to 9-Staff-100

b) The Applicant has indicated that the claim amount for 1595 (2016) has changed because it originally included 1595 (2017) amounts because an older version of the DVA continuity schedule had been used. The claim amount in 1595 (2016) had originally been a credit to customers. However in the updated DVA continuity both the 1595 (2016) and 1595 (2017) are debits. Why did the account change from a net credit to two debits for both 1595 (2016) and 1595 (2017).

RESPONSE

The 1595 (2016) claim amount in the original submission was misstated and revised in the submission with interrogatory responses. The original submission incorrectly included a principal adjustment disposition of $549,724 in 2018, which resulted a net credit balance from over recovery. Principal disposition on 1595 (2016) was not approved beyond 2017 and the DVA Continuity has been updated to present no disposition on this account in 2018.

The DVA Continuity workbook for the original submission did not have a row for the 1595 (2017) claim amount. The principal balance amount of $49,448 was included on the row for 1595 (2016). The debit balance of this account remains unchanged in the revised submission, it has only been reclassified.

OEB Staff - Settlement Proposal - Clarification Question 6

Ref: Table 4-8, Overall OM&A Cost Trends

a) In this table the Applicant indicates that maintenance costs being allocated to capital projects has increased by 475,000 compared to 2014 (thereby decreasing OM&A). What is driving the increase in the allocation of these costs to capital projects? Aren't maintenance costs typically period costs, so why would the rate at which they are being capitalized increase?

RESPONSE

As described in Exhibit 4, Page 26 of 540, the $475,000 represents an increase in labour costs that have been allocated to capital projects, compared to the prior period, thereby resulting in a decrease in OM&A. This is principally explained by an increase in the level of capital investments. This does not reflect maintenance costs that were capitalized. Energy+ submits that perhaps this would have been better described as a decrease in maintenance operating labour expenditures due to the increased focus on capital investments, and in particular renewal capital investments.

CCC - Settlement Proposal - Clarification Question 1

Ref: CCC10, 11, 12 and 13

These questions provide detailed data for System Access, System Renewal, System Service and General Plant. Although it was not included in the questions could Energy + please provide the relevant data for 2018?

RESPONSE

Included in this response are updated tables as provided in Response to CCC 10, 11, 12, and 13 to include the 2018 Bridge Year. Energy+ notes that the Response to CCC 10, 11, 12, and 13 are based on the DSP as originally filed and do not include any revisions made through the IR process (e.g. changes to the facilities plans).

System Access Breakdown by Primary Drivers	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
System Expansion	$ 6,630,732	$ 1,241,958	$ 3,853,744	$ 1,875,657	$ 1,232,670	$ 1,235,115	$ 1,518,015	$ 1,567,115	$ 1,478,095	$ 1,401,315	$ 1,566,715
New Customer Connections	$ 683,240	$ 1,009,050	$ 730,073	$ 1,419,229	$ 1,265,964	$ 1,473,100	$ 1,488,500	$ 1,470,000	$ 1,470,000	$ 1,470,000	$ 1,470,000
Metering	$ -	$ -	$ -	$ -	$ -	$ -	$ 751,092	$ 420,900	$ 427,200	$ 433,600	$ 440,100
Relocations	$ 1,062,469	$ 1,529,813	$ 3,480,487	$ 2,190,643	$ 3,100,437	$ 2,714,800	$ 766,600	$ 548,900	$ 977,000	$ 629,800	$ 651,850
System Access Total	$ 8,376,441	$ 3,780,821	$ 8,064,304	$ 5,485,529	$ 5,599,071	$ 5,423,015	$ 4,524,207	$ 4,006,915	$ 4,352,295	$ 3,934,715	$ 4,128,665
Deferred Revenue	(717,867)	(756,000)	(4,496,000)	(2,763,000)	(3,212,000)	(2,133,000)	(817,000)	(769,000)	(886,000)	(772,000)	(782,000)
System Access (Net)	$ 7,658,574	$ 3,024,821	$ 3,568,304	$ 2,722,529	$ 2,387,071	$ 3,290,015	$ 3,707,207	$ 3,237,915	$ 3,466,295	$ 3,162,715	$ 3,346,665

System Renewal Breakdown by Primary	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Overhead Rebuild	$ 2,382,484	$1,296,760	$ 2,719,878	$ 3,520,239	$3,622,718	$ 2,747,700	$3,048,000	$ 2,801,750	$ 2,408,900	$ 5,726,950	$ 5,012,100
Pole Replacements	$ 555,656	$ 619,925	$ 557,401	$ 642,503	$1,054,235	$ 833,200	$ 548,100	$ 792,400	$ 950,400	$ 949,400	$ 949,400
Line Transformers Capitalized	$ 87,974	$ 467,247	$ 306,845	$ 679,308	$ 360,752	$ 450,000	$ 450,000	$ 450,000	$ 450,000	$ 450,000	$ 450,000
Underground Rebuild	$ 874,171	$1,105,822	$ 1,602,478	$ 2,527,892	$3,500,366	$ 994,300	$1,748,100	$ 3,273,550	$ 2,669,865	$ 195,000	$ 1,251,700
Porcelain Insulator Replacements with Polymer	$ -	$ 110,684	$ 113,498	$ 86,683	$ 266,670	$ 317,000	$ 362,000	$ 362,000	$ 362,000	$ 362,000	$ 362,000
Vault Lid Replacements	$ 247,239	$ 4,916	$ -	$ 72,697	$ 97,049	$ 132,000	$ 132,000	$ 66,000	$ 66,000	$ 66,000	$ 66,000
Porcelain SMD-20 / Fault Tamer Replacements	$ -	$ 56,387	$ 82,370	$ 242,425	$ 138,427	$ 110,500	$ 110,500	$ 110,500	$ 110,500	$ 110,500	$ 110,500
Switchgear Replacements	$ -	$ -	$ 82,823	$ 116,334	$ 112,884	$ 85,000	$ 85,000	$ 170,000	$ 255,000	$ 255,000	$ 255,000
Pad-mounted Transformer Replacements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 83,000	$ 83,000	$ 83,000	$ 83,000
MTS Equipment Renewal	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 70,000	$ 70,000	$ 70,000	$ 70,000
Load-break Switch Replacements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 62,000	$ 31,000	$ 31,000	$ 62,000
Misc	424,020	699,652	$ 603,524	$ 304,943	$ 317,365	$ 149,000	$ 169,000	$ 350,000	$ 550,000	$ 550,000	$ -
System Renewal Total	$ 4,571,544	4,361,392	6,068,818	8,193,024	9,470,467	5,818,700	6,652,700	8,591,200	8,006,665	8,848,850	8,671,700

System Service Breakdown by Primary Drivers	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Enhanced Switching	$ 258,610	$ 98,853	$ 584,391	$ 187,583	$ 23,737	$ 298,000	$ 271,000	$ 301,000	$ 400,000	$ 240,000	$ 240,000
Feeder Improvements	$ 599,831	$ 482,456	$ 814,400	$ 530,876	$ 63,593	$ 2,233,100	$ 69,000	$ 281,600	$ 523,600	$ 181,600	$ 181,600
Enhanced Fault Detection	$ -	$ -	$ -	$ -	$ -	$ -	$ 27,000	$ 8,500	$ 30,000	$ -	$ -
System Service Total	$ 858,441	$ 581,309	$ 1,398,791	$ 718,459	$ 87,330	$ 2,531,100	$ 367,000	$ 591,100	$ 953,600	$ 421,600	$ 421,600

General Plant Breakdown by Primary Drivers	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Buildings	$ 416,000	$ 230,000	$ 84,000	$ 39,000	$ 394,000	$ 20,000	$ 4,400,000	$ 4,500,000	$ 150,000	$ 2,000,000	$ 150,000
Information System Technology	$ 162,000	$ 52,000	$ 125,000	$ 14,000	$ 34,000	$ 823,900	$ 767,000	$ 523,000	$ 850,000	$ 850,000	$ 900,000
Vehicles	$ 686,000	$ 1,543,000	$ 1,290,000	$ 857,000	$ 830,000	$ 100,000	$ 105,000	$ 543,000	$ 548,000	$ 388,000	$ 590,000
Tools and Equipment	$ 612,000	$ 848,000	$ 596,000	$ 468,000	$ 419,000	$ 95,500	$ 67,000	$ 90,000	$ 95,000	$ 100,000	$ 100,000
Office Equipment and Furniture	$ 162,000	$ 68,000	$ 45,000	$ 88,000	$ 175,000	$ 16,700	$ 4,000	$ 500,000	$ 25,000	$ 200,000	$ 25,000
Meters*	$ 697,000	$ 296,000	$ 197,000	$	320,000 $	$ 824,242	$ -	$ -	$ -	$ -	$ -
General Plant Total	$ 2,038,000	$ 2,741,000	$	2,140,000	$ 1,466,000	$ 1,852,000	$ 1,056,100	$	5,343,000	$ 6,156,000	$

Note: Meters excluded from historical totals to provide an equal comparison between 2013-

CCC - Settlement Proposal - Clarification Question 2

Ref: CCC-27

Kinetrics provided the following comments:

“In general, data quality of Cambridge and Brant areas is the same or better than the majority of local distribution utilities that Kinetrics has worked with so far. In terms of completeness, there was no asset group in which Energy + collected less data than the majority of utilities did.”

Please provide Kinetrics’ perspective on the quality and completeness of the data of the majority of local distribution utilities.

<u>RESPONSE</u>

Energy+ requested that Kinectrics provide comments on this follow up question and received the following response:

“The following table summarizes the comparison between Energy+ and the majority of local distribution utilities, in terms of data quality and completeness”

Data Type	Age		Inspection		Test		Service Record	
	Energy+	Majority of LDC	Energy+	Majority of LDC	Energy+	Majority of LDC	Energy+	Majority of LDC
Station Transformers	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Station Circuit Breakers	Yes	Yes	Yes	Yes	Yes		Yes	
Voltage Regulators	Yes	Yes	Yes					
Capacitors	Yes	Yes	Yes					
OH Line Switches	Yes	Yes	Yes					
OH Line Reclosers	Yes	Yes	Yes					
Pole Mounted Transformers	Yes	Yes					Yes	
Wood Poles	Yes	Yes			Yes			
Concrete Poles	Yes	Yes						
Steel Poles	Yes	Yes						
Pad Mounted Transformers	Yes	Yes	Yes	Yes			Yes	
Pad Mounted Switchgear	Yes	Yes	Yes	Yes				
Vault Transformers	Yes	Yes					Yes	
Submersible Transformers	Yes	Yes					Yes	
UG primary Cables (km)	Yes	Yes						

CCC - Settlement Proposal - Clarification Question 3

Ref: CCC-32

Please clarify how Energy + went about reducing the capital budget by $1 million. Was it a top down (look for $1 million in reductions or deferrals) or was it a bottom up approach?

<u>RESPONSE</u>

Energy+ made a top down decision to look for reductions in the capital budget by $1 million dollars while factoring in customer feedback, the results of the Asset Condition Assessment, and assessing implications to the Distribution System Plan.

VECC - Settlement Proposal - Clarification Question 1

Ref: 3-VECC-17

Please provide the customer/connection count by rate class as of June 30, 2018.

RESPONSE

The following is the Energy+ customer/connection count by rate class as of June 30, 2018.

Energy+ Customer Counts /Connection

Rate Class	Jun-18
Residential	57,929
GS < 50	6,379
GS > 50 - 999 kW	652
GS > 1000 kW	21
GS > 50 - 4,999 kW	117
Large Users	2
USL	486
Sentinel	163
Streetlights	16,155
Embedded Generation	2
Total	82,559

VECC - Settlement Proposal - Clarification Question 2

Ref: 3-VECC-20

a) For those months in 2018 where the data is available, please provide the comparable values for the unemployment variable.

RESPONSE

The following provides the values for the unemployment variable from January 2018 to October 2018

Jan-18	31.6
Feb-18	36.5
Mar-18	41.7
Apr-18	42.8
May-18	43.4
Jun-18	41.9
Jul-18	41.4
Aug-18	38.5
Sep-18	34.3
Oct-18	31.7

VECC - Settlement Proposal - Clarification Question 3

Ref: 3-Staff-53

4-Staff-64 a) i) - Updated CND_OEB LRAMVA Work Form

a) Please confirm that the 2016 values set out in Tab 9 of the updated LRAMVA Work Form represent the difference between: i) the monthly maximum peak demand based on the sum of the hourly metered (i.e., billing demand) load plus the hourly self-generation and ii) the metered monthly peak load (i.e., billing demand).
b) If not, please provide a table that sets out these values for each month in 2016.
c) Please confirm whether the 2017 values set out in Tab 9 of the updated LRAMVA Work Form represent the difference between: i) the maximum monthly peak demand based on the sum of the hourly metered (i.e., billing demand) load plus the hourly self-generation and ii) the metered monthly peak load (i.e., billing demand).
d) If not, please provide a table that sets out these values for each month in 2017.
e) What was the maximum hourly combined output of the two generators for each month in 2016 and 2017?
f) What was the minimum hourly combined output of the two generators for each months in 2016 and 2017?

RESPONSE

a) The 2016 values set out in Tab 9 of the updated LRAMVA Work Form represent the difference between: i) the hour in each month with the highest sum of billing demand and self-generation and ii) the hour in each month with the highest billing demand. Please refer to the Response to OEB Staff Follow-Up Question Number 6.
b) Please refer to OEB Staff Follow-Up Question Number 6.
c) The 2017 values set out in Tab 9 of the updated LRAMVA Work Form represent the difference between: i) the hour in each month with the highest sum of billing demand and self-generation and ii) the hour in each month with the highest billing demand. Please refer to the Response to OEB Staff Follow-Up Question Number 6.
d) Please refer to OEB Staff Follow-Up Question Number 6.
e) Please refer to table below.
f) Please refer to table below.

[redacted]

[redacted]

[redacted]

VECC - Settlement Proposal - Clarification Question 4

Ref: 4-Staff-65 a) and b)
4-Staff-64 a) i) - Updated BCP_OEB LRAMVA Work Form

a) Please explain more fully why the fact Direct Market Participants did not participate in the IESO's provincially funded CDM programs offered by Energy+ during 2014 to 2017 gives rise for the need for the 1,254,827 kWh adjustment to the CND LRAMVA threshold as opposed to simply re-assigning the threshold attributed to the Direct Market Participant to the relevant customer classes.

b) Please provide a specific reference to EB-2010-0125 record regarding the 1,494,000 kWh threshold used for the Brant County LRAMVA claim.

RESPONSE

a) In retrospect, Energy+ agrees that the CDM threshold for the CND Direct Market Participants should have been allocated to the relevant customer classes, specifically the GS>50-999 kW and GS 1,000-4,999 customer classes.

b) The 1,494,000 is the estimated 2011 CDM results for CDM from JT1.1 p.2, JT1.3 p.4, and JT 1.5 p.7 of the BCP Undertakings (File name: Brant_Undertaking Resp_JT1.1 - JT1.14_20110323.PDF). Received by the OEB 2011-03-23.

VECC - Settlement Proposal - Clarification Question 5

Ref: 7-VECC-44

a) In which customer classes are the seven GS customers and for each class how many connections and meters are associated with the customers?

RESPONSE

Out of the seven (7) GS customers, six (6) customers are in the GS >1000-4999 kW Class and one (1) customer is in the GS >50-999kW Class.

For the GS>1000-4999kW Class, there are 12 connections (2 per customer) and 13 meters.

For GS>50-999kW Class, there are two connections and 2 meters.

VECC - Settlement Proposal - Clarification Question 6

Ref: 3-VECC-19 a) and Updated Load Forecast Model (LFM) 7-Staff-76 b) and Updated Cost Allocation Model (CAM) 7-VECC-47 a)

b) For each of the supply points discussed in VECC-47 a) under Hydro One Networks Inc. # 2 (Brant Service Territory), the text indicates that is “normally” supplied from Hydro One owned facilities? Is power ever supplied to HON at these points using Energy+’s distribution facilities?

i. If yes, under what circumstances?

ii. If yes, why shouldn’t this “customer” be allocated a portion of the costs of Energy+’s distribution network?

RESPONSE

i. In the case of Hydro One Networks Inc. # 2 (Brant Service Territory), there were no instances found when power was supplied using alternative feeders and/or Transformation (>50kV) owned by Energy+.

ii. The answer to part (i) was no.

VECC - Settlement Proposal - Clarification Question 7

Ref: Updated Load Profile Model (2006 HON data for 2019)
7-Staff-76 b) and Updated Cost Allocation Model (CAM)
7-Staff 84 a)
7-Staff 85 a)

a) Please provide revised response to Staff 84 a) based on 2017 data as used in the updated Load Forecast and updated CAM.

<u>RESPONSE</u>

a) The following provides a revision to the table that was included in response to Staff 84 a). The table has been revised to reflect 2017 data used in the updated Load Forecast and updated CAM.

[redacted]

[redacted]

VECC - Settlement Proposal - Clarification Question 7

Ref: Updated Load Profile Model (2006 HON data for 2019)
7-Staff-76 b) and Updated Cost Allocation Model (CAM)
7-Staff 84 a)
7-Staff 85 a)

b) Please provide a revised response to Staff 85 a) based on the updated Load Forecast and updated CAM.

RESPONSE

The following provides a revision to the tables that were included in response to Staff 85 a). The tables have been revised based on the updated Load Forecast and updated CAM.

GS > 50 to 999 kW

	Load Profile Model	Cost Allocation Model	Difference	Reason
1 CP	73,655	75,161	1,506	Impact of WMPs assigned to this class
4 CP	292,011	298,034	6,023	
12 CP	847,739	865,809	18,069	
1 NCP	82,827	84,332	1,506	
4 NCP	326,869	332,892	6,023	
12 NCP	954,919	972,988	18,069	

GS > 1,000 to 4,999 kW

	Load Profile Model	Cost Allocation Model	Difference	Reason
1 CP	36,416	40,572	4,156	Impact of WMPs assigned to this class
4 CP	142,076	158,700	16,624	
12 CP	396,280	446,153	49,872	
1 NCP	40,787	44,943	4,156	
4 NCP	155,783	172,407	16,624	
12 NCP	444,745	494,617	49,872	

Large Use

	Load Profile Model	Cost Allocation Model	Difference	Reason
1 CP	20,848	20,848	-	Impact of Standby Demand Units
4 CP	86,707	88,898	2,191	
12 CP	259,575	290,018	30,443	
1 NCP	26,546	26,546	-	
4 NCP	102,987	105,178	2,191	
12 NCP	286,587	317,030	30,443	

VECC - Settlement Proposal - Clarification Question 7

Ref: Updated Load Profile Model (2006 HON data for 2019)
7-Staff-76 b) and Updated Cost Allocation Model (CAM)
7-Staff 84 a)
7-Staff 85 a)

c) With respect to Staff 85 a), please explain how, for the GS 50-999 and GS 1,0004,999 classes the adjustment to incorporate the WMPs was calculated. In doing so, please explain why the % change in each of allocator's values is not the same (as one might expect if the adjustment was done by including the WMP energy in the total energy used to create the load profile).

RESPONSE

In the Load Forecast the kW forecast for the WMPs has been held constant at the 2017 value of 67,942 kW. Based on 2017 data, there is one WMP in the GS 50-999 class for distribution services. This customer represents 26.6% of the 67,942 kW or 18,069 kW. The remaining (i.e. 49,872 kW) is in the GS 1,000-4,999 class which represents the value for three customer. The adjustment to the GS 50-999 demand data in the cost allocation model to incorporate the WMP assumes the 18,069 kW impacts the 12 CP and 12 NCP. 18,069 kW divided by 3 impacts the 4 CP and 4 NCP and 18,069 kW divided by 12 impacts the 1 CP and 1 NCP. The same process is used in the GS 1,000-4,999 class with the 49,872 kW impacting the 12 CP and 12 NCP and the other demand units are adjusted with the same approach. Energy+ did not include the WMP energy in the total energy used to create the load profile since the precision of the kWh associated with the WMP was not at the same level as the kW value since the kWh value is not used for billing purposes.

VECC - Settlement Proposal - Clarification Question 8

Ref: TMMC-4
TMMC Response to VECC 12.5
Updated CAM Model, Tab I6.1 (Revenue)
Updated LF Model, Rate Class Load Model Tab, Cell D11

Preamble: The response to TMMC-4, part 3 states:

The revenue requirement for rate setting purposes is determined in the following manner. The first step is to calculate the revenue that would be achieved from the Large User class assuming the demand from Standby does not exist. The calculated revenue amount is the current Large User rates increased by the average Energy+ 2019 distribution rate increase (i.e. 3.3%) times the Large User demand excluding Standby demand. The calculated revenue could be classified as revenue at existing rates increased by the average rate increase. (emphasis added)

a) Please confirm that, contrary to the response to TMMC-4, the 361,276 kW of billing demand for the Large Use class used in the updated CAM does include the 30,443 kW adjustment for Standby demand.

RESPONSE

Energy+ confirms that the 361,276 kW of billing demand for the Large Use class outlined in the updated LF model includes the 30,443 kW adjustment for Standby demand. However, for the purposes of calculating revenue at existing rates there has not been any existing revenue attributed to the 30,443 kW which is consistent with the statement provided in the Preamble.