Energy+ Inc.

2020 Incentive Regulation Mechanism ("IRM")
Distribution Rate Application

EB-2019-0031

For Rates Effective January 1, 2020

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O.

1998, c.15, (Schedule B);

AND IN THE MATTER OF an Application by Energy+ Inc. to the Ontario Energy Board for an Order or Orders approving or fixing just and reasonable distribution rates and other service charges to be effective January 1, 2020.

Appendices:

1. Contact Information

Applicant's Name:	Energy+ Inc. ("E+")
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2. Statement of Publication

Those affected by this Application are the electricity distribution customers of Energy+ Inc. (referred to in this Application as the “Applicant” or “Energy+” or “E+”) and encompass customers residing in two service territories: (i) the City of Cambridge and Township of North Dumfries (the service territory of the former Cambridge and North Dumfries Hydro Inc.) and (ii) within the County of Brant including the areas of Paris, St. George, Cainsville, and Burford and parts of the new City of Brantford as a result of the approved annexation between the City of Brantford and the County of Brant (the service territory of the former Brant County Power Inc.).

E+ proposes that notices related to this Application appear in publications relevant to each service territory. The Brantford Expositor News is a paid subscription newspaper with a circulation approximately 20,000 in the County of Brant. The Cambridge Times is a City of Cambridge based, non-paid subscription newspaper with a circulation of approximately 45,000. The Ayr News, is a Town of Ayr based paid subscription newspaper with a circulation of approximately 3,600 within the Township of North Dumfries.

3. Certification of Evidence

As Chief Financial Officer of Energy+ Inc., I certify, to the best of my knowledge, that the evidence filed in this 2020 IRM application is accurate, consistent and complete. The filing is consistent with the requirements of Chapter 3 of the Filing Requirements for Electricity Distribution Rate Applications, as last revised on July 15, 2019.

To the best of my knowledge, I certify that Energy+ has robust processes and internal controls in place for the preparation, review, verification and oversight of the deferral and variance account balances being disposed, consistent with the certification requirements in Chapter 1 and 3 of the Filing Requirements for Transmission and Distribution Rate Applications.

Sarah Hughes, CPA, CA

Original Signed by Sarah Hughes

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Chief Financial Officer

4. Manager's Summary

4.1. Corporate Overview

Energy+ Inc. ("E+") is a licensed electricity distributor (ED-2002-0574) that owns and operates the electricity distribution system in the City of Cambridge, the Township of North Dumfries, and certain areas within the County of Brant and the City of Brantford. E+ serves approximately 65,000 Residential, General Service, Large User, Street Light, Unmetered Scattered Load, Sentinel Light customers and connections. E+ also provides Low Voltage facilities to Hydro One Networks Inc., Brantford Power Inc., and Waterloo North Hydro Inc.

4.2. Application

4.2.1. Proposed Rate Adjustments

The Applicant hereby applies to the Ontario Energy Board ("OEB" or the "Board") pursuant to Section 78 of the *Ontario Energy Board Act, 1998* as amended (the "OEB Act") for approval of its proposed distribution rates and other charges provided on the basis of the 4th Generation Incentive Rate-setting ("Price Cap IR") effective January 1, 2020 (the "Application"). Energy+ previously applied for its rates effective January 1, 2019 under a Cost of Service rate application; EB-2018-0028.

The Applicant followed *Chapter 3 of the OEB's Filing Requirements for Electricity Distribution Rate Applications* last revised on July 15, 2019 (the "Chapter 3 Requirements"), and the Filing Instructions provided in the OEB's 2020 IRM Rate Generator Model Version 2.0, which incorporates the Retail Transmission Service Rates ("RTSR") model and the Tax Sharing model, referred to collectively as the 'Model', as provided to distributors by the OEB.

The Applicant is in receipt of the OEB's letter dated July 15, 2019, in which distributors were assigned to one of four streams, based on the complexity of the application the distributor was submitting. E+ was assigned to Stream 1, which required the 2020 IRM rate application to be filed by Monday, August 12, 2019. On August 7, 2019, E+ requested and was approved for an extension to the filing date to Monday, August 26, 2019.

Energy+ hereby applies to the OEB in this Application, for an Order or Orders approving the proposed distribution rates and other charges, effective January 1, 2020, as updated and adjusted in accordance with the Chapter 3 Filing Requirements, and include the following:

(i) An annual Incentive Rate Adjustment Mechanism of 1.05% applied to existing distribution rates. The adjustment is determined by the OEB's calculated inflation factor for incentive rate setting under the Price Cap IR Price Escalator of 1.2%, reduced by the Productivity Factor of 0.0%, and reduced further by the Stretch Value Factor of 0.15% (the rate effective for Group II utilities of which E+ is a part). E+ acknowledges that the Board will adjust the price escalator for 2020 Applications once the GDP IPI data becomes available;

(ii) an adjustment to rate design for residential electricity customers in accordance with the OEB's 'Board Policy: A New Distribution Rate Design for Residential Electricity Customers' (EB-2014-0210) and the Decision and Order from E+'s 2019 Cost of Service Application (EB-2018-0028);

(iii) an adjustment to the retail transmission service rates;

(iv) disposition of Group 1 Deferral and Variance accounts, representing a net disposition to customers in the amount of ($2,363,864) over a 12-month period;

(v) a Rate Rider for Disposition of Variance – WMS Sub Account CBR Class B;

(vi) disposition of the Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA"), representing a recovery from customers in the amount of $762,915 over a 12-month period;

(vii) an Incremental Capital Module Rate Rider for incremental capital related to the proposed Shared Operations Facility with Brantford Power Inc. to service the Brant County service territory, representing a recovery from customers in the amount of $405,799 per year until Energy+'s next rebasing application;

(viii) a Rate Rider for the disposition of the Gain on Sale of the former operations facility in Paris, Ontario, representing a disposition to customers in the amount of ($137,287) per year, or ($411,861) over three years; and

(ix) continuation of rates and charges as detailed in EB-2018-0028 including the Rate Rider for Smart Meter Entity Charge, the Rate Rider for Forgone Revenue, the Low Voltage Service Rate, the Wholesale Market Service Rate, the Rural or Remote Electricity Rate Protection Charge, the Standard Supply Service – Administrative Charge (if applicable), the MicroFIT Generator Service Classification Service Charge, the Transformer Allowance for Ownership, the Primary Metering Allowance for transformer losses, the specific service charges, Retail Service Charges and loss factors.

In the event that the Board is unable to provide a Decision and Order in this Application for implementation by the Applicant as of January 1, 2020, E+ requests that the Board issue an Interim Rate Order declaring the current Distribution Rates and Specific Service Charges as interim until such time as the 2020 rates are approved.

In the event that the effective date does not coincide with the Board's decided implementation date for 2020 Distribution Rates and Charges, E+ requests to be permitted to recover the incremental revenue from the effective date to the implementation date.

4.2.2. Summary of Bill Impacts

Table 1: Summary of Bill Impacts summarizes the bill impacts arising from all of the requested rate adjustments in this Application. The typical residential consumption used is 750 kWh, consistent with the *Report of the Board – Defining Ontario's Typical Residential Customer.*

Table 1: Summary of Bill Impacts

Rate Class	kWh	kW	Distribution (Fixed & Volumetric)				Total Bill (Excluding HST)			
			Current	Proposed	$ Change	% Impact	Current	Proposed	$ Change	% Impact
Residential	750		$ 28.03	$ 28.07	$ 0.04	0.1%	$ 103.38	$ 104.59	$ 1.21	1.2%
Residential	320		$ 26.91	$ 28.07	$ 1.16	4.3%	$ 61.41	$ 62.32	$ 0.91	1.5%
GS<50 kW	2,000		$ 46.96	$ 47.52	$ 0.56	1.2%	$ 240.37	$ 247.30	$ 6.94	2.9%
GS> 50 to 999 kW	20,000	60	$ 329.40	$ 332.86	$ 3.45	1.0%	$ 3,103.04	$ 2,962.82	$ (140.21)	-4.5%
GS> 1,000 to 4,999 kW	800,000	2,000	$ 8,492.41	$ 8,581.49	$ 89.08	1.0%	$ 109,838.30	$ 108,690.66	$ (1,147.64)	-1.0%
Large Use	6,600,000	16,000	$ 35,656.07	$ 36,030.32	$ 374.25	1.0%	$ 894,040.25	$ 861,663.56	$ (32,376.69)	-3.6%
Unmetered Scattered Load	100		$ 7.25	$ 7.33	$ 0.08	1.1%	$ 16.86	$ 17.59	$ 0.73	4.3%
Street Lighting	400,000	700	$ 11,755.18	$ 11,878.61	$ 123.43	1.1%	$ 74,875.56	$ 61,767.75	$ (13,107.81)	-17.5%
Sentinel Lighting	10,000	29	$ 1,224.08	$ 1,236.94	$ 12.85	1.1%	$ 2,560.85	$ 2,353.00	$ (207.85)	-8.1%
Embedded Distributor - Hydro One CND	1,382,000	2,574	$ 5,431.65	$ 5,488.80	$ 57.14	1.1%	$ 177,061.64	$ 175,498.03	$ (1,563.61)	-0.9%
Embedded Distributor - Waterloo North Hydro		8,280	$ 13,563.47	$ 13,705.88	$ 142.42	1.0%	$ 28,619.24	$ 46,692.59	$ 18,073.34	63.2%
Embedded Distributor - Brantford	50,000	27	$ 253.14	$ 255.80	$ 2.66	1.0%	$ 6,400.18	$ 6,200.85	$ (199.33)	-3.1%
Embedded Distributor - Hydro One #1	1,300,000	2,340	$ 2,833.10	$ 2,862.84	$ 29.75	1.0%	$ 161,794.98	$ 159,642.21	$ (2,152.78)	-1.3%
Embedded Distributor - Hydro One #2	1,990,000	4,050	$ 69.79	$ 70.52	$ 0.73	1.0%	$ 230,880.29	$ 229,099.37	$ (1,780.92)	-0.8%

4.3. Elements of the Price Cap IR

This Manager's Summary will address the Elements of the Price Cap IR, as detailed in the Filing Requirements as follows:

- Annual Adjustment Mechanism
- Revenue-to-Cost Ratio Adjustments
- Rate Design for Residential Electricity Customers
- Electricity Distribution Retail Transmission Service Rates
- Review and Disposition of Group 1 Deferral and Variance Account Balances
- LRAM Variance Account (LRAMVA)
- Incremental Capital Module (ICM)

- Tax Changes
- Z-Factor Claims
- Other Matters

4.3.1. Annual Adjustment Mechanism

The annual adjustment mechanism is defined as the annual percentage change in the Inflation factor less an X-factor (i.e. productivity factor and stretch factor). In the *PEG Empirical Research in Support of Incentive Rate-Setting: 2018 Benchmarking Update, August 2019*, E+ was placed in Group 2 for Stretch Factor Assignments and allows for a Stretch Factor adjustment of 0.15% for the 2020 rate year. E+ has calculated a proxy price cap adjustment of 1.05%, comprised of the price escalator of 1.20% less the associated Stretch Factor Value of 0.15%. E+ acknowledges that the Board will adjust the E+ Rate Generator Model with the updated price escalator once the updated GDP IPI data becomes available.

Table 2: Proposed Distribution Rates summarize the Fixed Service Charges and the Variable Volumetric Rates as approved for January 1, 2019, and as proposed for January 1, 2020.

Table 2: Proposed Distribution Rates

Rate Class	Billing Determinant	Fixed Service Charge		Variable Volumetric Rate	
		Jan 1, 2019	Proposed Jan 1, 2020	Jan 1, 2019	Proposed Jan 1, 2020
Residential	kWh	$ 26.08	$ 28.07	$ 0.0026	$ -
GS<50 kW	kWh	$ 14.96	$ 15.12	$ 0.0160	$ 0.0162
GS> 50 to 999 kW	kW	$ 102.34	$ 103.41	$ 3.7844	$ 3.8241
GS> 1,000 to 4,999 kW	kW	$ 864.41	$ 873.49	$ 3.8140	$ 3.8540
Large Use	kW	$ 8,976.07	$ 9,070.32	$ 1.6675	$ 1.6850
Unmetered Scattered Load	kWh	$ 5.82	$ 5.88	$ 0.0143	$ 0.0145
Street Lighting	kW	$ 1.90	$ 1.92	$ 15.3084	$ 15.4691
Sentinel Lighting	kW	$ 2.82	$ 2.85	$ 42.1125	$ 42.5547
Embedded Distributor - Hydro One CND	kW	$ -	$ -	$ 2.1102	$ 2.1324
Embedded Distributor - Waterloo North Hydro	kW	$ -	$ -	$ 1.6381	$ 1.6553
Embedded Distributor - Brantford	kW	$ -	$ -	$ 9.3755	$ 9.4739
Embedded Distributor - Hydro One #1	kW	$ 69.79	$ 70.52	$ 1.1809	$ 1.1933
Embedded Distributor - Hydro One #2	kW	$ 69.79	$ 70.52	$ -	$ -

4.3.2. Revenue-to-Cost Ratio Adjustments

The most recent Cost of Service Rate Application (EB-2018-0028) for rates effective January 1, 2019 did not prescribe a phase-in period to adjust its revenue-to-cost ratios. Energy+ does not propose any changes to its existing Revenue-to-Cost Ratios.

4.3.3. Rate Design for Residential Electricity Customers

On April 2, 2015, The OEB released the *Report of the Board: A New Rate Design for Electricity Residential Customers (EB-2012-0410)* and determined that residential distribution rates would move to a fully-fixed monthly charge over a four-year period. This transition process requires that the fixed charge is increased gradually while the volumetric charge is reduced slowly, so that the customer rate impact and the distributors residential class revenue remains neutral.

In the 2016 Rate Applications[1], E+ received approval to begin the transition of residential rates to a fully-fixed rate over a four-year period in both of its service territories. In the 2019 Cost of Service Application[2], Energy+ proposed and was approved to extend the transition of residential rates to a fully-fixed rate for one additional year to mitigate the low volume residential bill impacts.

In this Application, E+ is proposing the final transition to a fully fixed rate for residential customers, effective January 1, 2020 consistent with the 2019 Decision an Order. E+ has followed the approach on Tab 16 of the 2020 IRM Rate Generator Model.

As illustrated on Tab 16 of the 2020 IRM Rate Generator Model for E+, the final year of the transition to fully fixed monthly distribution rates for E+ customers results in a $1.99 per month increase in the fixed service charge and a $0.0026 per kWh decrease for the volumetric rate. The annual increase in the E+ residential fixed monthly charge will be less than $4 and therefore no mitigation measures are proposed by E+.

The OEB has established that, when assessing the combined effects of the transition to fixed rates and other bill impacts associated with changes in the cost of distribution service, a utility shall evaluate the total bill impact for a residential customer at the distributor's 10th consumption percentile.

[1] CND EB-2015-0057 Decision and Order, BCP EB-2015-0054 Decision and Order
[2] Energy+ EB-2018-0028 Decision and Order

E+'s method to derive the 10th consumption percentile is as follows:

- E+ extracted the total 2018 monthly consumption and by premise/account for all residential customers from the Customer Information System, adjusting for consumption that straddled the beginning and end of the year.
- E+ identified all residential customers with active service and consumption for the full year; customers with less than 12 months of service were excluded.
- The average monthly consumption was then calculated by premise/account.

E+ has determined that the E+ consumption level at the 10th percentile for 2018 is 320 kWh. The data set, comprised of 57,054 records, was sorted from smallest to largest by average monthly consumption. An index of 5,705 was calculated by taking the total number of records in the data set, multiplied by 10%. This customer has average monthly consumption of 320 kWh, representing the 10th consumption percentile for E+ residential customers.

The proposed rate impact for distribution charges only for residential consumption of 320 kWh is an increase of $1.16 or 4.3%. The proposed total bill impact is an increase of $0.91 or 1.5%. Given that the total bill impact is less than 10%, no mitigation measures are proposed by E+.

4.3.4. Total Bill Impacts > 10% Threshold

The Chapter 3 filing requirements state that a distributor must file a mitigation plan if the total bill impacts for any rate class exceed a 10% threshold. The Embedded Distributor – Waterloo North Hydro class has a 2020 total bill of $46,693, which is $18,073 or 63% higher than the 2019 total bill of $28,619. The change is attributable to an increase in the Deferral and Variance Account rate rider ($16,123) and Volumetric Rate Riders ($3,156) in comparison to 2019. This is a result of the credit to customers from the D&V accounts disposed during the 2019 Cost of Service Application being higher than the disposition request in the 2020 IRM Application. The D&V rate riders for 2019 included both Group 1 and Group 2 variance accounts, compared to just Group 1 variance accounts in 2020, and were based on a five-month disposition period, compared to 12 months in this Application. Energy+ is not recommending mitigation for this rate class.

4.3.5. Retail Transmission Service Rates

E+ is requesting the Boards approval to charge the Retail Transmission Service Rates ("RTSR") as calculated on a preliminary basis in the Model. The Filing Requirements indicate that Board will adjust each distributor's 2020 RTSR section of the Rate Generator to incorporate the January 1, 2020 UTR rates. The proposed RTSRs were determined by completing the Board approved model using RRR data from 2018 and historical data as billed by the IESO, Hydro One, and Brantford Power Inc. The transformation connection rate billing determinants for the GS > 50 to 999 kW, GS 1,000 to 4,999 kW and Large Use classes have been increased to include the gross load billing adjustments utilized and approved in the 2019 Cost of Service Application. Table 3: Proposed RTSR Rates summarizes the proposed RTSR rates for E+, as calculated by the Model.

Table 3: Proposed RTSR Rates

Rate Class	Billing Determinant	Network		Connection	
		Jan 1, 2019	Proposed Jan 1, 2020	Jan 1, 2019	Proposed Jan 1, 2020
Residential	kWh	$0.0060	$0.0060	$0.0045	$0.0042
GS<50 kW	kWh	$0.0054	$0.0054	$0.0041	$0.0039
GS> 50 to 999 kW	kW	$3.1657	$3.1399	$2.3638	$2.2222
GS> 50 to 999 kW - Interval Metered <1000 kW	kW	$3.1878	$3.1618	$2.3876	$2.2446
GS> 1,000 to 4,999 kW	kW	$2.3178	$2.2989	$1.6403	$1.5420
Large Use	kW	$2.3839	$2.3645	$1.6548	$1.5557
Unmetered Scattered Load	kWh	$0.0052	$0.0052	$0.0041	$0.0039
Street Lighting	kW	$1.6865	$1.6728	$1.2650	$1.1892
Sentinel Lighting	kW	$1.8501	$1.8351	$1.2233	$1.1500
Embedded Distributor - Hydro One CND	kW	$2.3839	$2.3645	$2.0269	$1.9055
Embedded Distributor - Waterloo North Hydro	kW	$2.3839	$2.3645	$2.0269	$1.9055
Embedded Distributor - Brantford	kW	$2.6625	$2.6408	$1.6731	$1.5729
Embedded Distributor - Hydro One #1	kW	$2.6625	$2.6408	$1.6731	$1.5729
Embedded Distributor - Hydro One #2	kW	$0.0000	$0.0000	$0.0000	$0.0000

The 2018 actual consumption and demand figures used in the 2020 RTSR connection rate calculations were higher for many rate classes than the consumption and demand figures from the 2019 Cost of Service load forecast used to calculate the 2019 RTSR connection rates. The increase in billing determinants and the changes to the allocation of forecast costs by rate class results in lower RTSR connection rates that are outside of the 4% threshold in the 2020 IRM Model. Table 4: RTSR Connection Billing Determinants and Table 5: RTSR Connection Forecast Allocation summarize the billing determinants and the forecast RTSR connection costs used in the calculations. The factors above did not have the same impact on the RTSR network rates due to a higher relative increase in the forecast costs.

Table 4: RTSR Connection Billing Determinants

Rate Class	Unit	2020 IRM	2019 Cost of Service	Difference
Residential	kWh	512,631,009	475,613,262	37,017,747
General Service Less Than 50 kW	kWh	209,230,835	199,918,821	9,312,014
General Service 50 to 999 kW	kW	471,191	539,150	- 67,960
General Service 50 to 999 kW - Interval	kW	1,344,854	1,029,406	315,449
General Service 1,000 To 4,999 kW	kW	629,184	588,206	40,978
Large Use	kW	432,523	405,209	27,314
Unmetered Scattered Load	kWh	2,317,675	2,343,765	- 26,090
Street Lighting	kW	16,492	10,945	5,547
Sentinel Lighting	kW	256	343	- 87
Embedded Distributor - Hydro One Cnd	kW	28,538	24,387	4,151
Embedded Distributor - Waterloo North Hydro	kW	115,378	114,657	721
Embedded Distributor - Brantford	kW	1,473	1,075	398
Embedded Distributor - Hydro One #1	kW	28,303	29,011	- 708

Table 5: RTSR Connection Forecast Allocation

Rate Class	2020 IRM	2019 Cost of Service	Difference
Residential	2,168,656	2,117,500	51,156
General Service Less Than 50 kW	806,460	811,588	- 5,128
General Service 50 to 999 kW	1,047,082	1,274,429	- 227,347
General Service 50 to 999 kW - Interval	3,018,631	2,457,826	560,805
General Service 1,000 To 4,999 kW	970,229	964,851	5,377
Large Use	672,865	670,557	2,308
Unmetered Scattered Load	8,933	9,681	- 747
Street Lighting	19,613	13,846	5,767
Sentinel Lighting	294	419	- 125
Embedded Distributor - Hydro One Cnd	54,379	49,430	4,949
Embedded Distributor - Waterloo North Hydro	219,851	232,395	- 12,544
Embedded Distributor - Brantford	2,317	1,798	518
Embedded Distributor - Hydro One #1	44,517	48,537	- 4,020
Total	**9,033,826**	**8,652,856**	**380,970**

4.3.6. Review and Disposition of Group 1 Deferral and Variance Account Balances

E+ has included a request for approval for the disposition of Group 1 Deferral and Variance Accounts based on the balances at December 31, 2018 and the forecasted interest to December 31, 2019 in this Application.

4.3.6.1. Summary of Accounts for Disposition

E+ has completed the Deferral and Variance account continuity schedules embedded in the 2020 IRM Rate Generator Model. The following section describes the balances and proposed recoveries and dispositions on Group 1 Deferral and Variance accounts.

E+ is requesting approval for disposition of Group 1 Deferral and Variance ("D&V") accounts in the amount of ($2,363,864). This amount represents the net balances at December 31, 2018, plus carrying charges computed to December 31, 2019.

E+ has completed the Deferral and Variance account continuity schedule embedded in the 2020 IRM Rate Generator Model and confirms that the balance in the Group 1 Deferral and Variance accounts exceeds the $0.001/kwh threshold test. The last disposition of Group 1 account balances occurred in the 2019 Cost of Service Application, and was based on 2017 balances.

In tab 4. Billing Det. for Def-Var of the 2020 IRM Model, Energy+ has included billing determinants of 60,766,638 kWh to Embedded Distributor – Waterloo North Hydro for purposes of allocating D&V account balances. These figures were not included in the 2018 RRR submission, and represent the reconciling item between the data sets.

Table 6: Proposed Deferral and Variance Accounts for Disposition summarizes the D&V Accounts proposed for disposition.

Table 6: Proposed Deferral and Variance Accounts for Disposition

Account Number	Account Description	Principal Balance at December 31, 2018	Carrying Charges to December 31, 2018	Projected Interest to December 31, 2019	Total Claim
1550	LV Variance Account	$ (387,755)	$ (3,237)	$ (8,715)	$ (399,707)
1551	Smart Metering Entity Charge Variance Account	$ (34,615)	$ (390)	$ (778)	$ (35,784)
1580	RSVA - Wholesale Market Service Charge	$ (207,460)	$ (27,494)	$ (4,663)	$ (239,617)
1580	Variance WMS – Sub-account CBR Class B	$ (73,372)	$ 3,546	$ (1,649)	$ (71,474)
1584	RSVA - Retail Transmission Network Charge	$ (333,112)	$ 8,735	$ (7,487)	$ (331,864)
1586	RSVA - Retail Transmission Connection Charge	$ 494,597	$ 10,555	$ 11,116	$ 516,269
1588	RSVA - Power	$ (391,496)	$ (29,324)	$ (8,799)	$ (429,619)
1589	RSVA - Global Adjustment	$ (1,347,762)	$ 5,986	$ (30,291)	$ (1,372,067)
Total		**$ (2,280,974)**	**$ (31,625)**	**$ (51,265)**	**$ (2,363,864)**

The Group 1 Balances proposed for disposition in the amount of $2,363,864 CR, represents 2018 ending balances plus carrying charges to December 31, 2019.

Table 7: Proposed Deferral and Variance Account Rate Riders summarizes the proposed Deferral and Variance Account Rate Riders by rate class.

Table 7: Proposed Deferral and Variance Account Rate Riders

Rate Class	Unit	Rate Rider for Disposition of D&V Accounts	Rate Rider for Disposition of D&V Accounts Non-WMP	Account LRAMVA 1568 Rate Rider	CBR Class B Rate Rider	Unit	GA Rate Rider	Unit	Rate Rider for Recovery of Incremental Capital	Rate Rider for Gain on Sale of Property
Residential	kWh	$ (0.0006)		$ 0.0002	$ (0.0001)	kWh	$ (0.0020)	Cust.	$ 0.32	$ (0.11)
GS<50 kW	kWh	$ (0.0005)		$ 0.0009	$ (0.0001)	kWh	$ (0.0020)	Cust.	$ 0.64	$ (0.22)
GS> 50 to 999 kW	kW	$ (0.0345)	$ (0.1086)	$ 0.1192	$ (0.0141)	kWh	$ (0.0020)	Cust.	$ 8.38	$ (2.83)
GS> 1,000 to 4,999 kW	kW	$ (0.0526)	$ (0.1613)	$ 0.0660	$ (0.0130)	kWh	$ (0.0020)	Cust.	$ 85.89	$ (29.41)
Large Use	kW	$ (0.2050)		$ 0.4868	$ (0.0204)	kWh	$ (0.0020)	Cust.	$ 372.61	$ (125.95)
Unmetered Scattered Load	kWh	$ (0.0005)		$ (0.0003)	$ (0.0001)	kWh	$ (0.0020)	Conn.	$ 0.13	$ (0.04)
Street Lighting	kW	$ (0.1843)		$ 4.0328	$ (0.0183)	kWh	$ (0.0020)	Conn.	$ 0.03	$ (0.01)
Sentinel Lighting	kW	$ (0.0285)			$ (0.0039)	kWh	$ -	Conn.	$ 0.12	$ (0.04)
Embedded Distributor - Hydro One CND	kW	$ (0.2396)			$ (0.0238)	kWh	$ (0.0020)	Cust.	$ 55.92	$ (18.90)
Embedded Distributor - Waterloo North Hydro	kW	$ (0.2686)			$ (0.0266)	kWh	$ (0.0020)	Cust.	$ 55.92	$ (18.90)
Embedded Distributor - Brantford	kW	$ (0.1442)			$ (0.0143)	kWh	$ (0.0020)	Cust.	$ 55.92	$ (18.90)
Embedded Distributor - Hydro One #1	kW	$ (0.2354)			$ (0.0234)	kWh	$ (0.0020)	Cust.	$ 55.92	$ (18.90)
Embedded Distributor - Hydro One #2	kW	$ (0.2070)			$ (0.0205)	kWh	$ (0.0020)	Cust.	$ 55.92	$ (18.90)

E+ confirms that as of December 31, 2018 E+ had Class A Customers. E+ has completed Tab 6 Class A Consumption Data and the resulting proposed rate riders were calculated in Tab 6.1a GA Allocation of the 2020 IRM Rate Generator Model.

E+ has also followed the methodology in the 2020 IRM Rate Generator Model to determine the rate rider for Disposition of Variance – WMS Sub Account CBR Class B.

The E+ Deferral and Variance Account Continuity Schedule is included in Appendix A, 2020 IRM Rate Generator Model Tabs 1 to 17.

4.3.6.2. Adjustments to Deferral and Variance Accounts

4.3.6.2.1. Principle Adjustments in 2018 D&V Account Continuity Schedule

Table 8: 2018 Principal Adjustments in D&V Continuity Schedule summarizes the principal adjustments made to the RSVA Power (1588), RSVA Global Adjustment (1589) and LRAMVA (1568) accounts.

Table 8: 2018 Principal Adjustments in D&V Continuity Schedule

Account	Account Description	Principal	Interest	Description
1588	RSVA Power	$ 640,180	$ -	Reversal of 2017 principal adjustment
		$ 669,995	$ -	Adjustment for revised commodity accounting process
		$ 1,310,175	$ -	
1589	RSVA Global Adjustment	$ (640,180)	$ -	Reversal of 2017 principal adjustment
		$ (4,541)	$ -	Adjustment for revised commodity accounting process
		$ (644,721)	$ -	
1568	LRAMVA	$ (354,276)	$ (28,319)	Reversal of 2017 principal adjustment
		$ 332,178	$ (4,101)	Adjustment for 2018 claim true-up
		$ (22,097)	$ (32,420)	

RSVA Power (1588) and RSVA Global Adjustment (1589)

During the 2019 Cost of Service, Energy+ identified adjustments that were required to correct the RPP / Non-RPP split of GA costs for 2017. The adjusting entry was recorded to the GL in 2018 to the RSVA Power and RSVA Global Adjustment accounts. The entry credited $640,180 to RSVA Power with an offsetting debit to RSVA Global Adjustment. The adjusting entry was reported as a principal adjustment in the 2017 D&V Continuity Schedule approved in the 2019 Cost of Service Application. Since the adjusting entry was posted in 2018 it is included as part of the 2018 transactions in the D&V Continuity Schedule submitted with this application, and as a result have been reversed as 2018 principal adjustments.

Energy+ has also made a principal adjustment related to the revised Accounting Guidance for Commodity Accounts. Table 9: Principal Adjustments from Revised Settlement Process summarizes the differences between the previous and revised Settlement process that have been captured as principal adjustments. An overview of the changes to the Settlement process can be found in Section 4.3.6.2.3 New Accounting Guidance.

Table 9: Principal Adjustments from Revised Settlement Process

	2018 Actual	2018 Revised	Difference
Revenue			
Commodity	(84,899,821)	(84,269,754)	630,067
Global Adjustment	(83,516,089)	(83,312,835)	203,254
Expense			
Commodity	83,838,326	83,878,254	39,928
Global Adjustment	82,173,988	81,966,193	(207,795)
DVAs			
Commodity	(1,061,495)	(391,500)	669,995
Global Adjustment	(1,342,101)	(1,346,642)	(4,541)

The principal adjustments related to the revised Settlement process, $669,995 for 1588 and ($4,541) for 1589, are the reconciling items between the balances in the D&V Continuity Schedule and the 2018 RRR balances for the respective accounts.

Lost Revenue Adjustment Mechanism Variance Account 1568

Energy+ recorded an LRAMVA balance of $1,163,117 as at December 31, 2017 but was approved for $1,545,722 in the 2019 Cost of Service application, resulting in a principal adjustment of $382,596. The adjustment comprises of $354,276 in principal and $28,320 in interest. The adjustment was recorded to the GL in 2018 and has been reversed in the 2018 principal adjustments in the D&V Continuity Schedule.

At 2018 year-end, Energy+ recorded an accrual of $439,056 for 2018 LRAMVA balances for based on preliminary results that were available from the IESO. Energy+ is requesting a disposition claim of $746,294 on 2018 balances, resulting in a 2018 principal adjustment of $307,238 that will be recorded to the GL in 2019. The adjustment comprises of $332,178 in principal and ($24,940) in interest. Energy+ has also recorded the 2019 Projected Interest on 2017 balances of $20,839 approved in the 2019 Cost of Service Application as a principal adjustment in 2018.

The adjustments related to 2018 of $332,178 in principle and ($24,940) in interest, as well as the 2019 Projected Interest of $20,893, total $328,077 and are the reconciling items between the LRAMVA balance in the D&V Continuity Schedule and the 2018 RRR balance.

4.3.6.2.2. Description of Settlement Process

The Board’s filing requirements for 2020 Rate Applications require each distributor to provide a description of its settlement process with the IESO or host distributor.

Distributors must specify the Global Adjustment (GA) rate used for billing each rate class, itemize the process for providing consumption to the IESO, and describe the true-up process to reconcile RPP consumption once GA actuals are published.

Energy+ does not have a host distributor and settles directly with the IESO.

Energy+ determines RPP eligibility for small business (General Service less than 50 kW) customers by performing an annual customer reclassification review based on the past 12 months of consumption. If the total consumption for the past 12 months is less than 250,000 kWh, the customer meets the RPP eligibility.

On a monthly basis, Energy+ calculates an amount payable/receivable to/from the IESO to settle for the previous month, as described in the next section. The settlement figures are submitted to the IESO through an online portal (formerly known as Form 1598), on or before the fourth business day of the month and is included under certain charge types on the IESO invoice, which arrives mid-month.

The RPP settlement process described below was in place throughout 2018. As a result of the revised Accounting Guidance for Commodity Accounts, Energy+ has identified changes to the RPP Settlement process that will be effective August 31, 2019. The changes to the process are outlined in Section 4.3.5.2.3. New Accounting Guidance.

Regulated Price Plan Settlement and True-up

On a monthly basis, on or before the first four business days following the previous month, Energy+ claims the difference between Regulated Price Plan (RPP) rates applied to RPP customers, and the sum of the corresponding consumption multiplied by the Weighted Average Hourly Spot Price (WAHSP) and Global Adjustment (GA) in the IESO Settlement Portal.

The process is completed using Energy+’s statistics table from the Customer Information System (CIS). For the current IESO settlement month, Energy+ extracts billed customer RPP commodity charges (TOU and tier pricing) along with the associated billed consumption from the statistics table in the CIS system. The CIS statistic table tracks all consumption and the associated charges billed at RPP rates for the current IESO settlement month.

For IESO settlement purposes, Energy+ has setup a separate statistic code in the CIS system to track WAHSP charges based on billed consumption for RPP customers. This calculation is stored in the statistic table. The billed RPP consumption is also included in the billing journal statistics history at the customer account level. This additional customer account level detail, enables Energy+ to settle RPP values against the actual GA rate for any energy consumed prior to the filing month.

Energy+ does not bill RPP customers on a calendar month basis. In order for Energy+ to settle and report on the actual GA rate for the month the energy was consumed, Energy+ pro-rates the billed consumption from the journal history statistics based on read dates and applies the actual GA rate against any consumption where the actual rate is available, and applies the IESO 2nd estimate to any consumption that falls in the current claim month. The actual GA rate for the prior month is posted on the 10th business day of the following month.

Energy+ submits a GA true up to the IESO for the prior month for any estimated GA rates. Energy+ calculates the Actual GA charges by applying the corresponding Actual GA rate against the consumption that was claimed in the previous submission at 2nd Estimate and the difference is then trued up on the following month's claim. Energy+ considers this process to be a monthly Global Adjustment true up of the RPP.

The dollar amount settled with the IESO is the difference between the sum of the WAHSP and GA calculation minus the billed RPP commodity (TOU and tier pricing). Energy+ maintains separate statistic codes to track the RPP settlement and GA settlement portions.

Allocation of Global Adjustment between RPP and Non-RPP Customers

The monthly loss-adjusted kWh sales are grouped into three categories: Class A kWhs, Class B Non-RPP kWhs, and Class B RPP kWhs. The proportion of Class B RPP kWhs reported to the IESO and the Class B Non-RPP kWhs is used to allocate the Global Adjustment dollar amounts billed by the IESO via Charge Type 148 between GL 4705 Power, and GL 4707 GA, respectively. Class A Global Adjustment amounts billed via Charge Type 147 on the IESO Invoice are allocated directly to GL account 4707 GA.

Global Adjustment amounts billed to Energy+ Inc. for Long-Term-Load-Transfers and Hydro One sub-transmission charges, are also allocated between Account 4705 Power and Account 4707 GA, using the proportion of Class B RPP and Class B Non-RPP kWhs.

Energy+ Inc. confirms that it uses accrual accounting.

Class A Customers

Effective July 1, 2015, O. Reg. 429/04 states that an eligible customer with a maximum hourly demand over three megawatts, but less than five megawatts can elect to become a Class A customer for an applicable adjustment period of one year. Table 1 details the number of Class A customers Energy+ historically serves.

Effective July 1, 2017 under the *Fair Hydro Act, 2017*, O. Reg. 429/04 was amended such that an eligible customer with a maximum hourly demand over one megawatt, but less than five megawatts, and manufacturing or greenhouse customers with average demand between 500-1,000 kW can elect to become a Class A customer for an applicable adjustment period of one year.

Annually, Energy+ reviews its Large customer Class A eligibility by calculating the customer's average peak demand during the twelve-month base period of May 1 to April 30.

For the May 1, 2017 to April 30, 2018 Base Period, if the customer has a monthly average peak demand above 1 MW, or between 500-1,000 kW and is identified by NAICS code commencing with "31", "32", "33" or "1114", the customer meets the eligibility of Class A for the July 1, 2017 to June 30, 2018 adjustment period. If the customer has a monthly average peak demand above 5 MW, the customer is automatically classified as a Class A customer. The customer must opt-out to be classified as a Class B customer.

Energy+ calculates its own peak demand factor (PDF) by collecting the sum of participating Class A customer demand during the top 5 Ontario peaks divided by the sum of Ontario's demand during the top 5 peaks (communicated by the IESO). Energy+ confirms its PDF calculation once it receives its PDF from the IESO at the end of May.

To settle Class A customers' actual GA amounts, Energy+ first calculates the total Ontario GA cost by taking the 147 - IESO charge and dividing it by Energy+ PDF (the sum of Energy+ Class A customers PDFs). The total GA costs are computed and then multiplied by a specific Class A customer's PDF to determine that customer's Class A GA charge for the month.

The second step is repeated for all Class A customers to determine their Class A GA charge for the month. The PDF for each individual Class A customer is calculated as the sum of the five customer demand peaks registered during the base period divided by the sum of the Ontario demand peaks determined by the IESO.

Renewable Energy Standard Offer Program (RESOP) Settlement Amount

Energy+ maintains a billing Code for each contract price that exists to date under the RESOP program. The CIS tracks the amount credited to RESOP customers at the applicable contract price during the month, it also tracks the value of the electricity which has flowed into Energy+'s distribution system from each RESOP generator (found by multiplying the kWh generated by the weighted average hourly spot price for the applicable billing period). The RESOP credit minus the WASHP is settled with the IESO.

Feed-In Tariff Program Settlement Amounts

Energy+ maintains a billing Code for each contract price that exists to date under the FIT and microFIT program. The CIS tracks the amount credited to FIT or microFIT customers at the applicable contract price during the month, it also tracks the value of the electricity which has flowed into Energy+ distribution system from each FIT and microFIT generator (found by multiplying the kWh generated by the weighted average hourly spot price for the applicable billing period). The FIT/microFIT credit minus the WASHP is settled with the IESO.

4.3.6.2.3. New Accounting Guidance

On February 21, 2019, the OEB issued its letter entitled Accounting Guidance related to Accounts 1588 Power, and 1589 RSVA Global Adjustment as well as the related accounting guidance. The accounting guidance is effective January 1, 2019 and is to be implemented by August 31, 2019. Energy+ has reviewed its RPP Settlement process and identified certain process changes required for compliance with the new guidance. The process changes will be in effect as of August 31, 2019.

As described in the 2018 RPP Settlement process documented above, Energy+ started its monthly RPP Settlement with the IESO based on billed consumption applied to the RPP TOU, Tier 1 and Tier 2 pricing. The billed consumption figures include amounts from the current month as well as prior months. For RPP settlement purposes those amounts were settled against the consumption applied to the actual GA rate for any consumption where the actual rate was available, and the IESO 2nd estimate GA rate to any consumption that fell in the current claim month. In subsequent months a true-up was prepared for any consumption that was settled using the IESO 2nd estimate GA rate to the actual GA rate.

With the revised process, the RPP consumption is estimated based on a total basis using meter data from the current month, and applied to the prior month's split of TOU, Tier 1 and Tier 2 consumption. The allocated amounts are then applied against the RPP TOU, Tier 1 and Tier 2 pricing. The revenue calculated will be settled against the total estimated consumption applied to the IESO 2nd estimate GA rate.

As a result of using estimated consumption and rates for the settlement, two true-ups are required. The first true-up will be prepared in the month following the initial RPP settlement claim. The first true-up revises the rates from the initial settlement and utilizes the actual GA and Power rates. The second true-up corrects the RPP consumption from the initial settlement and is prepared once the differences between estimated and actual RPP consumption is available in the CIS system.

Energy+ utilized the OEB's Illustrative Model issued with the new accounting guidance to asses the impact of the change in process on the 2018 D&V account balances. The analysis outlined adjustments that were required related to correct the consumption and the RPP / Non RPP split of GA costs.

Table 11: Principal Adjustments from Revised Settlement Process summarizes the differences that were calculated and included as principal adjustments in the D&V Continuity Schedule.

Table 11: Principal Adjustments from Revised Settlement Process

	2018 Actual	2018 Revised	Difference
Revenue			
Commodity	(84,899,821)	(84,269,754)	630,067
Global Adjustment	(83,516,089)	(83,312,835)	203,254
Expense			
Commodity	83,838,326	83,878,254	39,928
Global Adjustment	82,173,988	81,966,193	(207,795)
DVAs			
Commodity	(1,061,495)	(391,500)	669,995
Global Adjustment	(1,342,101)	(1,346,642)	(4,541)

4.3.6.2.4. Global Adjustment Analysis and Workform

Energy+ has completed the Global Adjustment Analysis Workform ("GA Workform") for 2018, which was been included in Appendix E GA Analysis Workform.

The purpose of the GA Workform is to compare the balance in Account 1589 to the expected balance based on Global Adjustment rates and E+'s consumption statistics. Discrepancies between the actual and expected balance are to be explained and quantified, and any remaining, unexplained discrepancy will be assessed for materiality. The OEB has set a threshold of +-1%

as the materiality threshold. The GA Analysis Workform indicates a variance of -0.3% for the 2018 transactions in Account 1589.

In the GA Analysis Workform, Energy+ has indicated that the table titled “Consumption Data Excluding for Loss Factor” is not consistent with the 2018 RRR data. Energy+ submitted a RRR revision for the Non-RPP Class A kWh that changed the value from 316,960,390 kWh to 312,372,764 kWh which was not reflected in the GA Analysis Workform model.

4.3.6.2.5. Certification of Evidence – Variance Accounts

As part of its Certification in Section 2, Energy+ indicated that it has robust processes and internal controls in place for the preparation, review, verification and oversight of the deferral and variance account balances being disposed.

As a result of the internal review of the Group 1 variance accounts, and recognizing the corrections required to the RSVA Power and RSVA Global Adjustment Accounts, Energy+ has made improvements to its processes, including the adoption of the updated Accounting Guidance Related to Commodity Pass-Through Accounts, as well as preparation of the accompanying Illustrative Model which has been a useful tool provided by the Ontario Energy Board.

4.3.7. LRAM Variance Account (LRAMVA)

Energy+ is requesting approval in this Application for a claim for recovery of the balance in its LRAMVA account of $762,915 including associated carrying charges (USoA Account 1568), as a December 31, 2018. The LRAM claim is for programs offered in 2018 and includes persistence of 2011 to 2017 results.

Energy+ based its LRAM claim using the IESO’s most recent Participation and Cost report (April 2019) and Value Added Services report (April 2019). The IESO’s Persistence Savings Report has not been issued, and the persistence of 2018 programs in future years will be evaluated in a future application. Since the preliminary IESO reports did not contain the same level of detail as the Final Verified Results report, Energy+ supplemented them with the project level details that Energy+ submitted monthly to the IESO. The project level details also supported the allocation of programs between service territory and rate class. The supporting reports are included in Appendix G – LRAMVA Supporting Reports.

The claim also contains persistence values for a 2016 Streetlighting project and a 2015 PSUI project that were calculated independently. The Streetlighting project persistence for 2018 was approved as part of the 2019 Cost of Service Application (EB-2018-0028). The 2018 persistence for the 2015 PSUI project was calculated using actual 2018 meter data from the customer's CHP generator and Energy+'s feed, consistent with the methodology approved in the 2019 Cost of Service Application.

Energy+ has completed the OEB's LRAMVA work form separately for each service territory as the IESO reported results for each of the former BCP and CND separately until the legal amalgamation in 2016, and separate distribution rates were maintained until the 2019 rate year. Copies of these reports, in working Microsoft Excel format, have been included as part of the Application material filed. Please refer to the D&V Continuity Schedule for the calculation of Energy+'s LRAMVA rate riders. Energy+ is proposing to dispose of the balance over a 12-month period. The amounts requested for recovery are summarized by rate class in Table 12: LRAMVA Claim by Rate Class.

Table 12: LRAMVA Claim by Rate Class

Energy+	Billing Unit	Principal ($)	Carrying Charges ($)	Total LRAMVA ($)
Residential	kWh	$ 72,953.27	$ 2,308.21	$ 75,261.48
GS<50 kW	kWh	$186,322.37	$ 5,895.16	$ 192,217.53
GS 50 to 999 kW	kW	$209,437.21	$ 6,626.51	$ 216,063.71
GS 1000 - 4,999	kW	$ 37,946.58	$ 1,200.61	$ 39,147.19
Large Use	kW	$168,993.39	$ 5,346.88	$ 174,340.27
Unmetered Scattered Load	kWh	$ (604.21)	$ (19.12)	$ (623.32)
Street Lighting	kW	$ 64,468.73	$ 2,039.76	$ 66,508.49
Total		**$739,517.34**	**$ 23,398.02**	**$ 762,915.36**

CND	Billing Unit	Principal ($)	Carrying Charges ($)	Total LRAMVA ($)
Residential	kWh	$ 50,465.63	$ 1,596.71	$ 52,062.34
GS<50 kW	kWh	$118,190.31	$ 3,739.49	$ 121,929.80
GS 50 to 999 kW	kW	$159,524.35	$ 5,047.28	$ 164,571.64
GS 1000 - 4,999	kW	$ 37,946.58	$ 1,200.61	$ 39,147.19
Large Use	kW	$168,993.39	$ 5,346.88	$ 174,340.27
Unmetered Scattered Load	kWh	$ (604.21)	$ (19.12)	$ (623.32)
Street Lighting	kW	$ (11,536.05)	$ (365.00)	$ (11,901.04)
Total		**$522,980.00**	**$ 16,546.87**	**$ 539,526.86**

BCP	Billing Unit	Principal ($)	Carrying Charges ($)	Total LRAMVA ($)
Residential	kWh	$ 22,487.64	$ 711.50	$ 23,199.14
GS<50 kW	kWh	$ 68,132.07	$ 2,155.67	$ 70,287.74
GS 50 to 999 kW	kW	$ 49,912.86	$ 1,579.22	$ 51,492.08
GS 1000 - 4,999	kW	$ -	$ -	$ -
Large Use	kW	$ -	$ -	$ -
Unmetered Scattered Load	kWh	$ -	$ -	$ -
Street Lighting	kW	$ 76,004.78	$ 2,404.76	$ 78,409.54
Sentinel Lighting	kW	$ -	$ -	$ -
Total		**$216,537.34**	**$ 6,851.15**	**$ 223,388.49**

4.3.8. Request for Deferral and Variance Account

Energy+ is seeking approval for the creation of a new deferral and variance account to capture the loss of other revenue related to the Board's generic rate order eliminating "Collection of

Account" charges for electricity distributors effective July 1, 2019[3], and based on the Board's Staff Bulletin dated August 8, 2019, which stated OEB staff's view that using the Notification Charge, or any other approved specific service charge for the purpose of charging for activities related to collection of accounts would be inconsistent with the OEB's decision to eliminate Collection of Account Charges.[4]

As part of Energy+'s 2019 Cost of Service Application for rates effective January 1, 2019, Energy+ applied for and received approval to charge a "Notification Charge" of $15.00. This charge is included in Energy+'s Schedule of Rates and Tariffs, approved effective August 1, 2019. Energy+ notes that the Notification Charge has been on the Schedule of Rates and Tariffs for Energy+ (and the former CND and BCP) since 2006.

As part of the approved 2019 revenue requirement, Energy+ included annual revenue of $278,000 for Document Charges, which is the other revenue account used for the Notification Charge.[5] Energy+'s practice, and approved tariff rate, is based on charging customers $15.00 when a notice of disconnection is required and is delivered to the customer.

Although Energy+ received its Decision and Order in June 2019, the 2019 approved revenue requirement was part of a Settlement Agreement reached in early December 2018 (prior to the Board's proposed amendments issued December 18, 2018) and the basis upon which the 2019 distribution rates have been established. If, based on the Board's generic rate order and the interpretation by OEB staff, Energy+ is no longer able to charge the Notification Charge, this will have a material financial impact on Energy+. As noted previously, the annual revenue impact is estimated at $278,000 per year. This is approximately $100,000 greater than Energy+'s materiality level of $175,000 used in the 2019 Cost of Service Application, and will have a cumulative impact over the next four years of approximately $973,000 until Energy+'s next scheduled rebasing, expected in 2023.

As such, Energy+ is requesting a new deferral and variance account to capture the loss of revenue. Energy+ submits that this request meets the criteria (materiality) and is consistent with the Board's findings in EB-2017-0183 *"Notice of Amendments to Codes and a Rule Amendments to the Distribution System Code, Standard Supply Service Code, Unit Sub-Metering Code, and Gas Distribution Access Rule and Notice of Hearing Review of Non-Payment of Account Service Charges for Electricity and Gas Distributors"* dated December 18,

[3] Rate Order (Non-Payment of Account Service Charges), March 14, 2019 (EB-2017-0183)
[4] OEB Staff Bulletin, August 8, 2019
[5] EB-2018-0028, DRO, Chapter 2 Appendices, Schedule 2H Other Revenue

2018 and as finalized on March 14, 2019. The following is an excerpt from the December 18, 2018 report:

"…the OEB acknowledges the electricity distributors comments that elimination of the two charges relating to non-payment of accounts may have an impact on some distributors. … A distributor can apply for a deferral account to track the impact of eliminating the two charges relating to non-payment of accounts with evidence demonstrating that such an account would meet the eligibility requirements set out in the OEB's Filing Requirements for Electricity Distribution Rate Applications."

4.3.9. Tax Changes

No tax changes are anticipated to result from changes in tax rates from E+'s most recent Cost of Service Application to 2019.

Consistent with the OEB's letter of July 25, 2019, Energy+ intends to book the impacts of the CCA rule changes resulting from Bill C-97 in account 1592-PILS and Tax Variances for all other affected capital additions. E+ expects the OEB will address the appropriate treatment of the accelerated CCA impact at Energy+'s next cost of service application, currently expected for 2023 distribution rates.

4.3.10. Z-Factor Claims

E+ is not applying for any Z-factor claims in this Application.

4.3.11. Other Matters

E+ has determined that there are no other matters to bring to the attention of the OEB at this time.

4.4. Elements Specific to the Price Cap IR Plan

4.4.1. Advanced Capital Module

E+ is not applying under the Advanced Capital Module ("ACM") in this Application. There were no ACM requests that were neither part of E+(CND)'s nor E+(Brant County)'s latest Cost of Service Rate Applications.

4.4.2. Incremental Capital Module

Energy + is seeking approval for incremental capital funding related to a $4.4MM capital lease investment in a shared Operations Facility with Brantford Power Inc. ("BPI"). This location will function as the Operations Centre to service customers in the Brant County Service territory.

In 2020, as part of a long-term lease agreement with Brantford Power Inc., Energy+' will occupy approximately 14,229 sq. ft. of dedicated space at a facility purchased by BPI in 2019 that is located at 150 Savannah Oaks Drive, near Oak Park Road and Highway 403 (“Savannah Oaks”) in Brantford, Ontario. Brantford Power Inc. has purchased an existing facility which will undergo renovations prior to occupancy.

Energy+ and BPI will also enter into a Shared Services Agreement for additional shared space and services that will provide for shared inventory, warehousing, purchasing and stores, fueling stations and vehicle maintenance.

This investment was identified in Energy+’s 2019 Cost of Service Application (“2019 CoS Application”) as part of its long-term Facilities Business Plan (EB-2018-0028). In the initial 2019 CoS Application, Energy+ had requested approval of an Advanced Capital Module for 2020.

In 2018, Energy+ sold the land and building located on Dundas St. in Paris, Ontario (“Dundas St.” or “Paris” facility) that is currently the Operations Centre for the Brant County service territory. As part of this sale, Energy+ entered into a sale leaseback transaction whereby Energy+ has a flexible lease that enables it to vacate the property within five years. Energy+ expects to terminate this lease in 2020 once it has occupied the shared space with BPI.

As part of the Settlement Agreement in the 2019 Cos Application, which was approved by the Ontario Energy Board in its Final Decision and Order dated June 13, 2019, Energy+ Inc. agreed to withdraw its request for 2020 ACM funding for the proposed shared facility with BPI. Energy+ agreed that it would be more efficient for the Board to consider the proposed facility at one time and to reduce the possibility of inconsistent decisions. The parties to the Settlement Agreement expected Energy+ to submit an Incremental Capital Module (“ICM”) request, together with a request to dispose the gain on sale of the Paris facility, concurrently with BPI’s ICM application.

On August 12, 2019 BPI submitted their 2020 rate application, which includes an ICM for the BPI portion of the shared facility (EB-2019-0022).

Table 13: ICM Funding Request summarizes the ICM funding request being sought by Energy+ Inc. in this Application.

Table 13: ICM Funding Request

Summary of ICM Funding Requested		
Total ICM Project Budget (Energy+ Exclusive Space)	$	4,395,862
Maximum Eligible Incremental Capital	$	11,820,128
Incremental Capital Requested	$	4,395,862
Incremental Revenue Requested		
Return on Rate Base	$	267,067
Amortization Expense	$	107,216
Gross Up Taxes/PILs	$	31,495
	$	405,779

In this Application, Energy+ is proposing to recover the incremental revenue associated with the rate base investment for the dedicated space to be occupied by Energy+ Inc. The Shared Service Agreement is expected to result in an annual operating lease, that is not incorporated into the ICM request.

Energy+ proposes to recover the incremental revenue through an ICM Rate Rider for each customer class. Energy+ is requesting that the ICM Rate Rider be effective until Energy+'s next Cost of Service rebasing, which is expected to be effective January 1, 2023.

In this Application, Energy+ is also proposing to dispose of the gain on sale realized on the Paris facility through a Gain on Sale Rate Rider for each customer class. Energy+ is requesting that the disposition of the Gain on Sale Rate Rider be disposed over a three-year period (January 1, 2020 to December 31, 2022). This proposal is aligned with the period of the ICM Rate Rider and will to help to mitigate the incremental revenue, and associated bill impacts, to customers related to the shared facility with BPI.

Table 14: Summary of Bill Impacts by Customer Class sets out: (i) the proposed allocation of the incremental revenue requirement; (ii) the proposed ICM Rate Rider; (iii) the proposed allocation of the Gain on Sale; (iv) the Gain on Sale Rate Rider; and (v) the estimated total bill impacts by customer class.

Table 14: Summary of Bill Impacts by Customer Class

Rate Class	Incremental Revenue from ICM	ICM Rate Rider	Gain on Sale Allocation	Gain on Sale Rate Rider	Total Allocated	Total Rate Rider
Residential	$ 228,220	$ 0.32	$ (77,142)	$ (0.11)	$ 151,079	$ 0.21
GS<50 kW	$ 49,644	$ 0.64	$ (16,781)	$ (0.22)	$ 32,864	$ 0.42
GS> 50 to 999 kW	$ 80,494	$ 8.38	$ (27,213)	$ (2.83)	$ 53,281	$ 5.55
GS> 1,000 to 4,999 kW	$ 27,825	$ 85.89	$ (9,528)	$ (29.41)	$ 18,297	$ 56.48
Large Use	$ 8,943	$ 372.61	$ (3,023)	$ (125.95)	$ 5,920	$ 246.66
Street Lighting	$ 6,277	$ 0.03	$ (2,122)	$ (0.01)	$ 4,155	$ 0.02
Unmetered Scattered Load	$ 786	$ 0.13	$ (266)	$ (0.04)	$ 520	$ 0.09
Sentinel Lighting	$ 235	$ 0.12	$ (79)	$ (0.04)	$ 155	$ 0.08
Embedded Distributors	$ 3,355	$ 55.92	$ (1,134)	$ (18.90)	$ 2,221	$ 37.02
Total	**$ 405,779**		**$ (137,287)**		**$ 268,492**	

Rate Class	Total Bill without ICM / Gain	Total Bill with ICM and Gain on Sale	Difference	Bill Impact
Residential	$ 104.38	$ 104.59	$ 0.21	0.2%
Residential Low Use	$ 62.11	$ 62.32	$ 0.21	0.3%
GS<50 kW	$ 246.88	$ 247.30	$ 0.42	0.2%
GS> 50 to 999 kW	$ 2,957.27	$ 2,962.82	$ 5.55	0.2%
GS> 1,000 to 4,999 kW	$ 108,634.18	$ 108,690.66	$ 56.48	0.1%
Large Use	$ 861,416.90	$ 861,663.56	$ 246.66	0.0%
Street Lighting	$ 17.50	$ 17.59	$ 0.09	0.5%
Unmetered Scattered Load	$ 61,767.73	$ 61,767.75	$ 0.02	0.0%
Sentinel Lighting	$ 2,352.92	$ 2,353.00	$ 0.08	0.0%
Embedded Distributor - Hydro One CND	$ 175,461.01	$ 175,498.03	$ 37.02	0.0%
Embedded Distributor - Waterloo North Hydro	$ 46,655.57	$ 46,692.59	$ 37.02	0.1%
Embedded Distributor - Brantford	$ 6,163.83	$ 6,200.85	$ 37.02	0.6%
Embedded Distributor - Hydro One #1	$ 159,605.19	$ 159,642.21	$ 37.02	0.0%
Embedded Distributor - Hydro One #2	$ 229,062.35	$ 229,099.37	$ 37.02	0.0%

4.4.2.1. ICM Filing Requirements

Energy+ is requesting ICM for a discrete material incremental capital project planned for 2020 that is not part of its typical capital programs, and therefore not funded through the existing distribution rates.

The Handbook to Utility Rate Applications dated October 13, 2016 states in the glossary of terms for the ICM:

"The Incremental Capital Module (ICM) is a capital tracker mechanism which allows for funding of significant capital investments for discreet projects during the period of incentive regulation between cost of service applications to rebase rates. Any qualifying ICM capital project must satisfy a materiality threshold to determine that the incremental capital amounts are beyond the normal level of capital expenditures expected to be funded by rates, including the effect of customer and load growth. An ICM request is requested and approved as part of a Price Cap IR application.".

On September 18, 2014 the OEB issued the *Report of the Board: New Policy Options for the Funding of Capital Investments: The Advanced Capital Module* and the *Report of the OEB on*

New Policy Options for the Funding of Capital Investments: Supplemental Report, dated January 22, 2016. Both reports are identified as EB-2014-0219 (the "Reports").

The Reports made changes to the materiality threshold on which ICM proposals are assessed, but otherwise did not alter the requirements for ICM proposals. In addition, the Board adopted a Means Test in qualifying for incremental capital funding. In accordance with the Reports, ICM funding will not be allowed if a distributor's regulated return exceeds 300 basis points above the deemed return on equity embedded in the distributor's rates.

Eligibility Criteria

The Reports indicate three eligibility criteria to recover amounts that are incremental to capital investment forming part of the ICM.

Criteria	Description
Materiality	A capital budget will be deemed to be material, and as such reflect eligible projects, if it exceeds the Board-defined materiality threshold. Any incremental capital amounts approved for recovery must fit within the total eligible incremental capital amount (as defined in this ACM Report) and must clearly have a significant influence on the operation of the distributor; otherwise they should be dealt with at rebasing. Minor expenditures in comparison to the overall capital budget should be considered ineligible for ACM or ICM treatment. A certain degree of project expenditure over and above the Board-defined threshold calculation is expected to be absorbed within the total capital budget.
Need	The distributor must pass the Means Test (as defined in this ACM Report). Amounts must be based on discrete projects, and should be directly related to the claimed driver. The amounts must be clearly outside of the base upon which the rates were derived.
Prudence	The amounts to be incurred must be prudent. This means that the distributor's decision to incur the amounts must represent the most cost-effective option (not necessarily least initial cost) for ratepayers.

Means Test

Energy+'s most recent rate rebasing was for 2019 distribution rates (effective August 1, 2019). The approved Regulated Return on Equity ("Regulated ROE") is 8.98% for 2019. Energy+ does not expect to exceed its Regulated ROE in 2019.

In 2018, the most recently completed fiscal year for which financial results are available, Energy+ earned a Regulated ROE of 8.68%, which was below the Deemed Return on Equity of 9.36% (based on the 2014 Cost of Service rate rebasing for the former Cambridge and North Dumfries

Hydro Inc.) and was not in excess of 300 basis points. Energy+'s regulated ROE for the years 2015 to 2018 inclusive have also been within 300 basis points.

Based upon the Means Test, Energy+ is eligible for ICM funding.

Materiality

The Board states in the Reports that the "*ICM was intended to address the treatment of capital investment needs that arise during the rate-setting plan which are incremental to a materiality threshold. The materiality threshold represented a distributor's financial capacities underpinned by existing rates, including growth".*

The Board-defined materiality threshold is calculated using the following formula:

$$\boldsymbol{Threshold\,Value}\,(\%) = \mathbf{1} + \left[\left(\frac{\boldsymbol{RB}}{\boldsymbol{d}}\right) \times (\boldsymbol{g} + \boldsymbol{PCI} \times (\mathbf{1} + \boldsymbol{g}))\right] \times \left((\mathbf{1} + \boldsymbol{g}) \times (\mathbf{1} + \boldsymbol{PCI})\right)^{\boldsymbol{n-1}} + \mathbf{10}\%$$

where:

RB = Approved rate base from the distributor's last Cost of Service application.

d = Approved depreciation expense from the distributor's last Cost of Service application.

g = Growth is calculated based on the percentage difference in distribution revenues between the most recent complete year and the distribution revenues form the most recent approved test year in a Cost of Service application.

PCI = Price Cap Index (IPI stretch factor) fixed at 0.9% at this time subject to updating.

n = Number of years since the last rebasing.

Energy+ has completed the OEB's ICM Model and confirms that the capital expenditure requirement for the Shared Facility meets the materiality threshold. Table 15: ICM Threshold Calculation summarizes the calculation of the Threshold Capital Expenditure amount. Table 16: Eligible Incremental Capital illustrates that the proposed capital expenditure is within the Maximum Eligible Incremental Capital Amount.

Energy+ notes that the PCI used in the ICM model defaults to 0.3% for all distributors and does not reflect the change in Energy+'s stretch factor of 0.15% by moving to Cohort 2 which was received on August 15, 2019.

Table 15: ICM Threshold Capital Expenditure Calculation

Threshold Capital Expenditure Calculation As per ICM Model	
Parameter	**Amount**
Price Cap Index	0.90%
Growth factor	-1.31%
Rate Base	$173,825,304
Depreciation	$6,269,103
Threshold Value for 2020	98%
Threshold Value for 2021	98%
Threshold Value for 2022	98%
Threshold Value for 2023	98%
Threshold CAPEX 2020	$6,155,872
Threshold CAPEX 2021	$6,159,023
Threshold CAPEX 2022	$6,162,161
Threshold CAPEX 2023	$6,165,286

Table 16: Eligible Incremental Capital

Eligible Incremental Capital	
	2020
Capital Expenditures, as per DSP	$17,976,000
Materiality Threshold	$6,155,872
Maximum Eligible Incremental Capital	$11,820,128
Proposed Capital Projects	**$4,395,862**
Maximum Allowed Incremental Capital	**$4,395,862**

Inputs into the ICM Model

Based upon the ICM model results, the $4.4MM proposed capital investment is above the materiality threshold and is therefore eligible for the ICM.

Energy+ notes that it has not reflected the recent changes to Capital Cost Allowance tax rules, resulting from Bill C-97, in its ICM calculations. Consistent with the OEB's letter of July 25, 2019, Energy+ intends to book the impacts of the CCA rule changes in account 1592-PILS and Tax Variances for this and all other affected capital additions. In order to avoid "double-counting" the impact of the accelerated CCA changes, Energy+ has calculated CCA related to the building using the methodology applicable for additions prior to November 20, 2018. Consistent with the letter, Energy+ expects the OEB will address the appropriate treatment of the accelerated CCA impact at Energy+'s next cost of service application, currently expected for 2023 distribution rates.

Need

The Reports state that any discrete projection (discretionary or otherwise) adequately supported in the DSP is eligible for ICM funding subject to capital funding availability flowing from the formula results. The amounts must be clearly outside of the base upon which the rates were derived.

In this regard, the investment in a shared facility with BPI is a discrete project, which was identified as part of Energy+'s Distribution System Capital Plan as a 2020 investment, and is outside of the base upon which the rates were derived in 2019.

As outlined in the long-term Facilities Business Plan filed in the 2019 CoS Application, over the past several years, as a result of customer growth following Cambridge and North Dumfries Hydro Inc's ("former CND") acquisition of Brant County Power Inc. ("former BCP") in 2014, increased staffing needs, aging facilities and inadequate space to house various business functions, Energy+ identified a need to review the status of its current facilities to ensure it is effectively meeting its customers' and employees' needs and prudently managing facilities-related expenses.

Energy+ is currently operating out of three facilities, two in the former Cambridge and North Dumfries ("former CND") service area and one in the Brant County ("former BCP") service area.

In the Brant County service territory, the Paris facility is in very poor condition. The administrative portion of the building was underutilized following the relocation of administrative staff to the corporate head office, currently located at Bishop St. in Cambridge, whereas the operational space is currently too small to accommodate anticipated growth in the Brant County service territory.

Over the next ten years, Energy+ expects an increase in construction activity in the Brant County service territory due to: i) customer growth; and ii) a renewal program as a result of aging infrastructure.

In 2018, Martin Simmons Architects prepared a Condition Study of the Paris facility, attached as Appendix F Exhibit I, which concluded the following[6]:

> This report concludes that this operations building be disposed of and a new facility be built either elsewhere on this site or on another appropriate property. The building contains a disturbingly large number of deficiencies that render it problematic for continued use as an operations centre for a public utility. Not only do these deficiencies raise safety, functional and comfort concerns, the facility is at the end of its useful life expectancy. Compromises in operations and maintenance are expected to continue should this facility remain in use. Furthermore, due to the building's age, configuration and construction, the building cannot be upgraded, modified or expanded to meet current and future functional or performance expectations. As well, due to the constricted location of the building on the site, no possibility exists to enlarge the building to accommodate needed program elements.
>
> As a result, the facility is not recommended for continued use as an Operations Centre. Neither is it recommended that the facility be renovated, refurbished or expanded to accommodate current and future needs. Energy+ Inc. should dispose of this building and look to alternative scenarios for a new Operations Centre.

As noted previously, Energy+ sold the Paris facility (land and building) in 2018 as part of a sale leaseback transaction, recognizing that this facility did not meet the long-term needs of Energy+ Inc. Under the terms of the lease, Energy+ leased the existing space, consisting of approximately 15,000 square feet of building space (comprised of approximately 5,000 square feet of administrative space and 9,376 square feet of operations space including a garage, and indoor storage) and 4.75 acres of land used for outdoor storage. The initial term of the lease is 2 years, effective March 31, 2018, with an option to extend the lease for the operations space only for up to an additional three years (extensions of one year each). Energy+ does not expect that the new owner will provide for any further extensions beyond the terms of the existing lease.

Energy+ expects to terminate this lease in 2020 once it has occupied the shared space with BPI.

As part of the Shared Facility plan, Energy+ will occupy approximately 14,229 sq. ft. of dedicated space, consisting of approximately 926 sq. ft of office space, 3,043 sq. ft of operations space (locker rooms/washrooms, workstations), and 10,260 sq. ft of vehicle garage.

[6] Energy+ Inc. Paris Operations Centre: Condition Study, September 10, 2018, Page 11.

The Shared Facility between Energy+ and BPI is an innovative approach to reducing costs (both operating and capital) in the future by sharing costs for facilities and services. Such an approach also aligns with encouraging partnerships between LDCs and finding efficiencies.

Impact of Disallowing ICM Funding

As noted by the OEB in the Reports, the ICM approach is intended to address the treatment of capital investment needs that arise during the rate-setting plan which are incremental to the materiality threshold, while allowing the distributor to obtain necessary recovery of capital investments on a planned and prioritized basis over the whole IR period. The ICM mechanism us in place and intended to provide utilities with an opportunity to establish reasonable rate impacts for customers.[7]

In the event that the OEB does not approve the ICM funding proposal, Energy+ has limited options with respect to its Operations Centre to service customers in the Brant Service territory. The lease term on the Paris facility will expire in 2023 and Energy+ would need to find an alternative location to the BPI facility. The option explored and agreed to between BPI and Energy+ is the most prudent option for Energy+ Inc. and BPI.

Energy+ is committed to a shared operations facility with BPI; As outlined in BPI's 2020 IRM Application (EB-2019-0022), the BPI facility has already been purchased.

The total financial impact to Energy+ Inc. for the period 2020 to the end of 2022 in the absence of funding would be approximately $543,000 per year (i.e. $342,383 in proposed ICM funding lost plus the after-tax effect of the incremental annual OM&A expenditures for the Shared Service Agreement), which is material to Energy+'s overall financial position. Energy+ would note that the incremental annual OM&A expenditures for the Shared Services Agreement were not included in the 2019 CoS Application and will be borne by the Shareholders of Energy+ until the time of the next rebasing, scheduled for January 1, 2023.

Energy+ would also note that if Energy+ did not proceed with the arrangement with BPI, this would have a material impact on both Energy+ Inc. and BPI. In particular:

- Under the terms of the Memorandum of Understanding, Energy+ would be subject to a termination fee of $635,000 payable to BPI, representing the estimated design costs incurred by BPI. This would represent a material expense to Energy+.

[7] Report of the Board *New Policy Options for the Funding of Capital Investments: The Advanced Capital Module,* September 18, 2014, Page 18.

- In its 2020 IRM Application, BPI has indicated that if BPI does not receive approval for its ICM funding, their financial results for 2020 are likely to be below 300 basis points the regulated rate of return. As highlighted in BPI's 2020 IRM Application, the request for ICM funding excludes any incremental revenue required for the capital costs that have been allocated to Energy+. This would have an additional impact to BPI that is not currently reflected in their Return on Equity analysis.[8]

Prudence

The amounts to be incurred must be prudent. This means that the distributor's decision to incur the amounts must represent the most cost-efficient option (not necessarily the least initial cost) for ratepayers.

As outlined in the Facilities Business Plan (EB-2018-0028, Exhibit 2, Appendix 2-1, Appendix N, and as updated in December 2018), Energy+ explored a number of options with respect to its facility requirements. During its review of options, Energy+ determined that the optimal solution for its space needs, from a customer and financial perspective, would be to maintain an Operations Centre in both the City of Cambridge and the Brant Service territory.

The alternatives considered by Energy+ for the Brant County service territory included:

- Renovate or rebuild the existing Dundas St. facility
- Lease space/co-locate with BPI
- Acquire/Lease new space in the Brant Service territory

In evaluating suitable facilities alternatives, Energy+'s management has been guided by the following decision objectives and priorities:

i. Maintain operational facilities to provide construction, maintenance, and emergency restoration services in Energy+'s service territory. Given the geography of the service territory, it is necessary to maintain two facilities – one to service the Brant County territory (256 square kilometers) and one to service the Cambridge and North Dumfries territory (306 square kilometers);

ii. Minimize costs to ratepayers by avoiding high cost facility solutions (cost of land, premium building construction / renovation);

[8] EB-2019-0022, 2020 ICM Page 39 of 40.

iii. Meet the needs of a growing utility in the future and maintain future flexibility by separating operational space from administrative space, allowing for: (a) administrative space to be expanded in the case of mergers or acquisitions or (b) greater options in the case a merger or sale that involves consolidating administrative functions in another city. Regardless of which scenario emerges, the two operations facilities will continue to be required to support operations, maintenance, restoration, and customer service;

iv. In the case of the Brant County facility, align considerations with BPI wherever possible to maximize shared service opportunities; and

v. Provide a comfortable and safe work environment for Energy+ employees.

Energy+ has taken a unique and very prudent approach to its overall facilities requirements, including the partnering with our neighbouring utility BPI.

The opportunity to share in the construction of a new facility with BPI was attractive for a number of reasons:

- The location is ideal, central to Energy+'s Brant County service territory with good access to major arterial roads.
- The opportunity to share costs of the new construction.
- An immediate opportunity for shared services – inventory, warehousing, fueling stations, purchasing and stores, vehicle maintenance, tower and shared vehicles.
- The opportunity to right size the mix of administrative office requirements with adequate operational space to accommodate anticipated customer growth and renewal projects within the Brant County service territory.
- Emergency preparedness considerations – allowing both utilities to respond to emergencies in a more efficient and effective manner.

One of the governing principles agreed to by both Energy+ and BPI in the Memorandum of Understanding is to ensure that customers benefit from the arrangement in comparison to each of Energy+ and BPI proceeding with obtaining, operating and maintaining their own, single use building.

In conjunction with BPI, there have been a number of due diligence steps undertaken with respect to this project including:

- Review of alternative sites;
- Detailed needs assessment with respect to the exclusive space to be occupied by Energy+;
- Identification of shared services opportunities;
- Assistance from qualified professionals at various stages throughout the planning and selection process; and
- Benchmarking.

Customer Feedback

As part of its 2019 CoS Application, Energy+ conducted a number of augmented customer engagement initiatives, including on-line customer workbooks, telephone surveys, customer workshops and key account meetings. As part of these initiatives, customers were specifically asked whether they supported Energy+'s proposed facilities plan.

As outlined in the Customer Engagement Executive Summary provided by Innovative Research Group ("IRG")[9], in both the County of Brant and Cambridge and North Dumfries, a large majority of low-volume customers either outright supported or felt that the proposed facility investments and associated costs were necessary. That said, based on feedback obtained throughout the process, customers expect Energy+ to be wise with their spending, and find ways to reduce impacts on distribution rates.

These views are largely consistent throughout the Energy+ service territory.

As part of the augmented customer engagement initiatives, customers were also asked to rank six identified customer needs and outcomes to better understand customer priorities. In the representative telephone surveys undertaken by IRG, continuing to pursue collaboration with other utilities, or other innovative solutions to reduce costs, was ranked in the top 3 for both residential and small business customers.[10]

Energy+ believes that it has met the requirements related to prudence.

[9] EB-2018-0028, Exhibit 1, Appendix 1-15, Page 407 of 1145
[10] EB-2018-0028, Exhibit 1, Appendix 1-15, Page 404 of 1145

4.4.2.2. Project Overview – Shared Facility with Brantford Power Inc.

4.4.2.2.1. Background on the Overall Energy+ Facilities Plan

Energy+ Inc. (“Energy+”) filed a comprehensive long-term Facilities Business Plan as part of its 2019 Cost of Service Application (“2019 CoS Application” (EB-2018-0028)).

As documented in the Facilities Business Plan, Energy+ completed a comprehensive, multi-year review of various alternatives, including renovating/rebuilding currently owned buildings, purchasing/renovating alternative facilities, leasing alternative facilities and construction of new facilities.

Energy+ developed the following plan with respect to its land and buildings:

- Purchase and renovate an existing building in downtown Cambridge, referred to as the “Southworks” facility. In June 2019, Energy+ completed the purchase of a portion of an existing building for $1, that will be renovated to make it suitable to be an administrative office. Energy+ expects to occupy this new space in 2022.
- Renovate and modernize the existing Cambridge building in 2022 (“Bishop St.” facility), which will continue to be utilized as the Operations Centre to service customers in the Cambridge and North Dumfries service territory. Administrative staff currently at the Bishop St. facility and Thompson Dr. facility (currently leased administrative space) will be relocated to the Southworks facility.
- As part of a long-term lease agreement, Energy+ will lease dedicated operations space from Brantford Power Inc. (“BPI”), as part of BPI’s new facility, which will function as the Operations Centre to service customers in the Brant County service territory. Energy+ is expected to occupy this space in the latter part of 2020.

  Energy+ and BPI will also enter into a Shared Services Agreement for additional shared space and services that will provide for shared inventory, warehousing, purchasing and stores, fueling stations and vehicle maintenance.

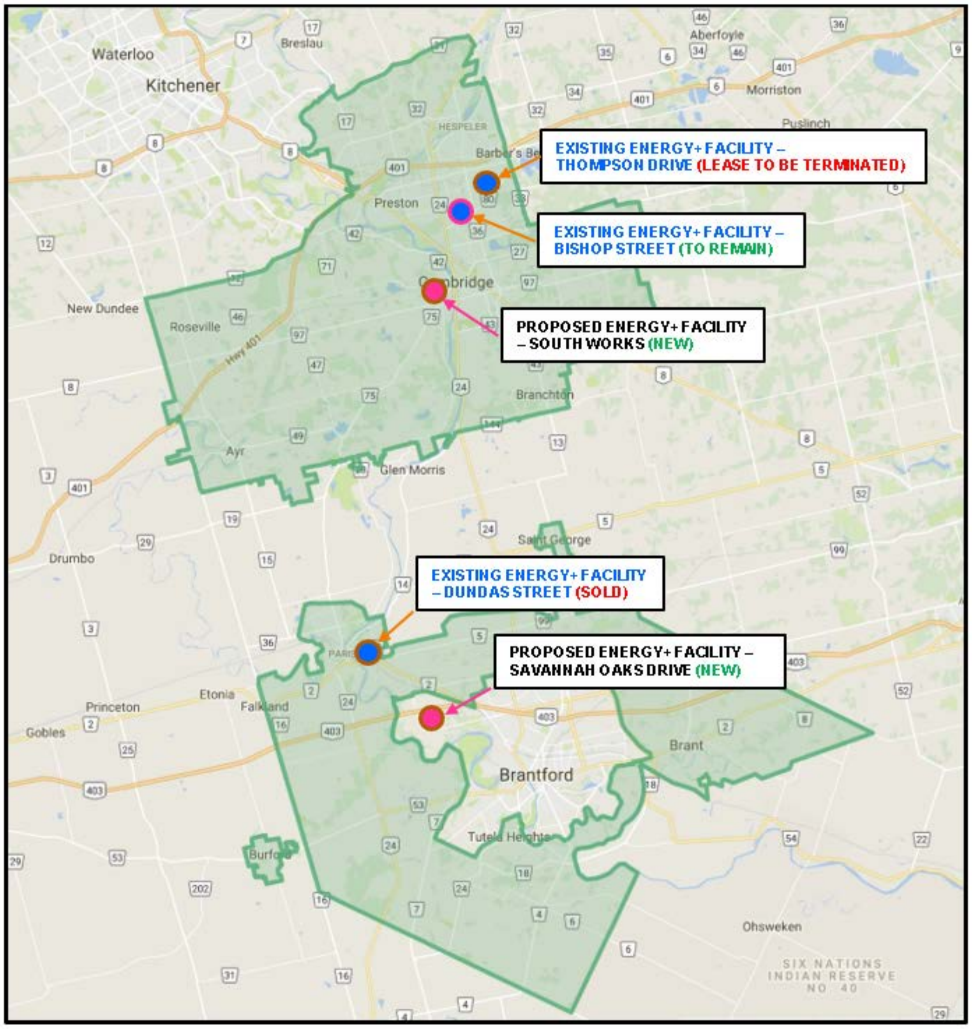
  In 2018, Energy+ sold the land and building located on Dundas St. in Paris, Ontario (“Dundas St.” or “Paris” facility), as part of a sale leaseback transaction. This location is currently the Operations Centre for the Brant County service territory. Energy+ has a flexible lease that enables it to vacate the property within five years. Energy+ expects to terminate this lease in 2020 once it has occupied the shared space with BPI.

In its Decision and Order dated June 13, 2019 (EB-2018-0028), the Ontario Energy Board (the "Board" or "OEB") approved Energy+'s Advanced Capital Module ("ACM") request for the Southworks Facility. In its Decision, the Board found that the need for the facility has been demonstrated based on the increasing number of employees, the acquisition of the former Brant County Power Inc. ("BCP"), and the efficiencies of consolidating the administrative staff. An aspect of this Decision is the subject of a motion to review, which is ongoing.

As part of the Settlement Agreement in the 2019 Cos Application, which was also approved by the Board, Energy+ Inc. agreed to withdraw its request for 2020 ACM funding for the proposed shared facility with BPI. Energy+ agreed that it would be more efficient for the Board to consider the proposed facility at one time and to reduce the possibility of inconsistent decisions. The parties to the Settlement Agreement expected Energy+ to submit an Incremental Capital Module ("ICM") request, together with a request to dispose the gain on sale of the Paris facility, concurrently with BPI's ICM application.

The following Figure 1: Energy+ Location of Facilities provides the location of the existing and proposed Energy+ facilities in the context of its service territories:

Figure 1: Energy+ Location of Facilities



4.4.2.2.2. Shared Facilities with BPI

For purposes of the ICM Application, Energy+ is providing updates to the Facilities Business Plan with respect to the Brant County service territory only, including an overall analysis of the total facilities costs for Energy+ Inc. as it relates to benchmarking.

4.4.2.2.3. Update to Facilities Business Plan

In 2020, as part of a long-term lease agreement with Brantford Power Inc., Energy+ will occupy approximately 14,229 sq. ft. of dedicated space, consisting of approximately 926 sq. ft of office space, 3,043 sq. ft of operations space (locker rooms/washrooms, workstations), and 10,260 sq. ft of vehicle garage at a facility located at 150 Savannah Oaks Drive in Brantford, Ontario. Energy+ will also have access to up to 13,705 square feet of shared space, including a warehouse, 2 mechanics bay, and common space. This location will function as the Operations Centre to service customers in the Brant County service territory.

Energy+ notes that the location of the Shared Facilities with BPI has changed from the location previously identified in the Energy+ 2019 CoS Application (previously referred to as the "Garden Avenue" facility).

Full details of the Shared Facilities property and buildings are provided as part of BPI's 2020 IRM Application (EB-2019-0022).

Energy+ and BPI have entered into a Memorandum of Understanding with respect to the Shared Facilities that is provided in Appendix F Exhibit II.

Energy+ will also enter into a Shared Services Agreement with BPI to share inventory, warehousing, a purchasing manager, a stores person, fueling stations and vehicle maintenance for the Shared Facilities. There will be significant efficiencies gained by drawing from a single inventory pool, yard, fueling station, and tower that will be shared and can service both Energy + and BPI. This will not only put both utilities in a position to provide excellent service to their customer bases, but also allow them to serve a growing customer base and respond to emergencies more efficiently and effectively.

The architectural drawings and floorplans of the Shared Facilities are provided in Appendix F Exhibit III.

Table 17: Total Capital Allocated to Energy+ for Exclusive Space provides a summary of the total capital expenditures allocated to Energy+ Inc. from BPI for the exclusive space to be occupied by Energy+ Inc.

Table 17: Total Capital Allocated to Energy+ Inc. for Exclusive Space

TOTAL CAPITAL ALLOCATED TO ENERGY+ FOR EXCLUSIVE SPACE								
Facility Component	Square Footage	Initial Purchase Price			Construction Costs	Total Cost		
		Building	Land	Total	Building	Building	Land	Total
Vehicle Storage Garage	10,260	$ -	$ -	$ -	$ 3,951,452	$ 3,951,452	$ -	$ 3,951,452
Administrative Office	926	$ 36,559	$ 30,484	$ 67,043	$ 36,641	$ 73,200	$ 30,484	$ 103,684
Operations Office	3,043	$ 120,139	$ 100,177	$ 220,316	$ 120,409	$ 240,548	$ 100,177	$ 340,725
Energy+ Exclusive Space Total	14,229	$ 156,698	$ 130,661	$ 287,359	$ 4,108,503	$ 4,265,201	$ 130,661	$ 4,395,862

Appendix F Exhibit IV provides the derivation of the allocation of capital costs received from BPI, including the allocation of BPI's original purchase price of the Savannah Oaks property, and the construction costs.

As the construction components of Shared Facilities plan are still to be completed, BPI has included estimates for some portions of the project budget. The cost certainty of the Savannah Oaks option is relatively less risky than the Garden Avenue option, as cost of the land and building are known, with only the new construction and refurbishment costs uncertain. By comparison, only the land purchase component of the Garden Avenue project was certain, with the construction cost uncertainty related to a greenfield contributing more risk.

The construction estimate currently included in BPI's project budget is at a Class D level, which is associated with a +/-30% level of certainty. BPI anticipates that it will have a Class C estimate available in September 2019.

4.4.2.2.4. Lease Accounting

Energy+'s rationale for the treatment of the costs associated with the exclusive space as a capital expenditure was based on an evaluation of accounting standards related to leases, including Article 425 (Accounting for Specific Items – Leases), which is based on the current IAS 17 standard that incorporates lease accounting, and IFRS 16 Standard for Leases, which was effective January 1, 2019. Currently the Accounting Procedures Handbook ("APH") does not address the new IFRS 16 Standard for Leases, however, as indicated in the APH, "the Board generally requires regulatory filing and reporting under IFRS, as modified for regulatory purposes by the Board."

The following is a summary of the assessment completed by Energy+:

Article 425 Accounting for Specific Items - Leases

Energy+ expects that the proposed lease agreement with BPI (based on the Memorandum of Understanding, including Guiding Principles, as a lease agreement has not yet been finalized), would meet the primary lease classification criteria with respect to a finance lease. Paragraphs 10 and 11 of IAS 17 provide a series of indicators that individually or in combination normally lead to the classification as a finance lease. Criteria considered included: (i) the lease term is the major part of the economic life of the asset even if title is not transferred; (ii) at the inception of the lease, the present value of the minimum lease payments amounts to at least substantially all of the fair value of the leased asset; and (iii) if the lessee can cancel the lease, the lessor's losses associated with the cancellation are borne by the lessee.

Under a finance lease, the leased asset and the lease liability are recognized at the lower of the fair value of the leased asset at inception of the lease; or the present value of the minimum lease payments at the inception of the lease.

APH Article 425, Pg. 8 Regulatory Treatment Considerations states:

> "Under a finance lease: A "finance" lease is essentially similar to a "capital" lease under previous Canadian GAAP. Accordingly, a finance lease will be given ratemaking consideration for inclusion in rate base".

IFRS 16 Leases

Effective January 1, 2019, Energy+ was subject to the IFRS 16 Standard on Leases.

- IFRS 16 applies to all leases, with some exemptions. Under IFRS 16, a contract is, or contains a lease if it conveys the right to control the use of an identified asset for a period of time in exchange for consideration. Control is conveyed where the customer has both the right to direct the identified assets' use and to obtain substantially all the economic benefits from that use.
- Energy+ understands that the new IFRS 16 standard will result in Energy+ recognizing a "right of use" asset on the balance sheet with a corresponding lease liability. Energy+ likens this treatment to the "capitalization" of property, plant, and equipment or a "finance" lease.
- IFRS 16 requires that a right-of-use asset is initially measured at the amount of the lease liability plus any initial direct costs incurred by the lessee. As Energy+ had an estimate of the underlying capital costs associated with the exclusive space, Energy+ utilized the total estimated capital costs for the ICM.

Based on the criteria, the Energy+ exclusive space would qualify as a capital lease, whereas the shared facilities and common space would be treated as an operating contract.

A lease requires a capital "right-of-use" asset to be established, which is calculated as the present value of the lease payments discounted at the interest rate implicit in the lease plus any lease payments made before the commencement date net of any lease incentives, any initial direct costs and any expected restoration obligation costs. The residual asset value after the lease term must also be included. If the contract outlines an option to extend the lease term, the extended term should be used in the calculation if it is a reasonable outcome. Table 18: Right of Use Asset Calculation provides a summary of the calculation.

Table 18: Right of Use Asset Calculation

Annual Lease Rate	$	23.23	/ sq. ft.
Square Footage		14,229	sq. ft.
Lease Term + Residual Asset Life		44.0	years
Implicit Rate		7.25%	
Present Value of Lease Payments		**$4,395,862**	

4.4.2.2.5. Needs Analysis

<u>Context</u>

The operations, maintenance and construction activities for the Brant territory are currently serviced predominantly from an operations centre located at the Dundas Street Facility. This facility requires refurbishing, as there have been no significant investments made to the building since it was first constructed. The total parcel of land on which the Dundas Street Facility is located is approximately 4.89 acres.

In November 2014, at the time of the acquisition of the former BCP, the Dundas Street Facility was utilized for administration, as well as operations. There were approximately 27 employees, including 15 administrative personnel and 12 operations and field personnel located at the Dundas Street Facility. As part of the Share Purchase Agreement between the former CNDHI and the Corporation of the County of Brant and recognizing the importance of ensuring an appropriate response time to respond to customer needs, Energy+ agreed to maintain a local presence at the Dundas Street Facility for a minimum period of five years following the closing date of the acquisition (November 28, 2014).

In 2015, following the acquisition and restructuring of the organization, administrative staff were relocated to the Bishop Street Building or the Thompson Drive Building, in order to achieve operating efficiencies and synergy savings. Currently, there are 13 operations staff, supporting the Brant County service area, that continue to be located at the Dundas Street Facility.

Throughout 2015 and 2016, Energy+ continued to explore options with respect to its space needs, including assessing the optimal solution for servicing multiple territories. During the review of options, Energy+ determined that the optimal solution for its space needs, from a customer and financial perspective, would be to maintain an operations centre in both the City of Cambridge and the County of Brant.

Given the size and geography of the CND and BCP service territories, there would be a number of drawbacks to consolidating the operations facilities including:

i. extensive travel time and response time to service customers, which would lead to increased costs and outage times; and

ii. increased capital costs for acquiring an entire operations facility that could accommodate the space requirement for all of Energy+'s crews, vehicles, and materials, compared to the options evaluated for Brant County and the estimated renovations at the Bishop St. Operations Centre.

<u>Brant County Facilities Background and Timeline</u>

1973 BCP's Dundas Street administrative facility was constructed in 1973. It is approximately 5,000 square feet of administrative space.

1984 BCP's Dundas Street operations facility was constructed in 1984. It is approximately 9,400 square feet of operations space that can accommodate 6 large powerline trucks.

2014 Energy+ acquires BCP. The Dundas Street Facility is determined to be a long-term requirement to service customers in Brant County due to the geography of the service territory and the distance from the Cambridge operations facility.

2016 Energy+ relocates 14 BCP administrative employees to Cambridge.

Energy+ assigns Cambridge operations construction crews to work on system renewal projects in the Brant County area which required crews to utilize the Dundas Street Facility for picking up materials.

2017 The Dundas Street Facility is determined to be no longer optimal for Energy+'s requirements. There is approximately 3,000 square feet of underutilized administrative space and a shortage of operational space. The age and condition of the building is also a growing concern due to roof leaks and mould contamination.

Energy+ is approached by BPI to explore interest in a new shared facility. BPI has been operating out of 3 separate premises since 2005, all of which are leased from its shareholder the City of Brantford. They were advised by their landlord that their leases will not be renewed as of January 1, 2022 as the City needed the space for expanded municipal operations or alternative uses, and therefore need to prepare to vacate their facilities by this date.

The opportunity to share a facility with BPI was attractive for a number of reasons:

- The proposed location is ideal, central to Energy+'s Brant County service territory with good access to major arterial roads.
- There is an ability to share the soft costs of the construction project, and the hard costs related to the shared facility space.
- There is an immediate opportunity for shared services – inventory, warehousing, fueling stations, purchasing and stores, vehicle maintenance, tower and shared vehicles.
- The facility could be right sized to address the mix of administrative office requirements and operational space required to accommodate anticipated customer growth and renewal projects within the Brant County service territory.
- It enhances emergency preparedness capabilities, allowing both utilities to respond to emergencies in a more efficient and effective manner.

After an extensive search process, BPI located and purchased a greenfield property located at Garden Ave. in Brantford with the intent of building a new facility. In June 2017 BPI engaged a project manager for its new facility project, and in September 2017, a Design Consultant was selected to further detail both BPI and Energy+'s requirements and to develop architectural drawings for the new build. Energy+ worked with BPI and the Design Consultant throughout 2017 and 2018 to develop the dedicated space requirements for Energy+, as well as the shared facilities.

Energy+ enters into a Purchase and Sale Agreement to sell the Dundas St. facility in a sale-leaseback transaction, subject to various conditions.

Energy+ and BPI enter into a Letter Agreement for the construction of a shared facility, whereby Energy+ commits to enter into a long-term lease agreement for dedicated space and the sharing of facilities to be built at Garden Ave. in Brantford, Ontario.

2018 The sale of the Dundas St. facility is completed and Energy+ enters into a lease agreement with the purchaser to continue to occupy the existing space. The term of the lease is for an initial two years, with additional renewals of one year, which is intended to provide the appropriate amount of time to complete the joint facility with BPI.

In early 2018, Energy+ worked with the new owner of the Dundas St. facility to vacate the administrative portion of the Dundas St. location to allow for new tenants, and the lease agreement is amended.

In late 2018, BPI issued an RFP for a builder for the facility at Garden Ave. with a cap on the bids of $27MM for the construction of the facility only. Additional project costs, including soft costs, permits and fees, furniture, fixtures and equipment were expected to bring the total project costs to $32MM. The capital costs for Energy+'s dedicated space was estimated at $4.4MM at that time. The cap placed on the RFP by BPI was based on assessments at a Class C level from the Design Consultant, verified by cost consultants, and represented the maximum price that BPI would pay for the new build project, with the expectation that the resultant bids would be lower than this cap.

BPI did not receive any bids on its RFP. Based on BPI's follow up with consultants with the firms which received the RFP, the informal feedback received by BPI was that the cap on the project was too low to make the project commercially attractive.

In late 2018, there was also a renewed interest from the seller at 150 Savannah Oaks ("Savannah Oaks Drive") for a sale of the property to BPI. This location had previously been identified by BPI as a suitable location for its new facilities.

2019 BPI purchases land and building located at 150 Savannah Oaks Drive near the border of BPI and Energy+ service territory ("**Savannah Oaks Drive**").

2019	BPI has been working with its Project Manager and with AECOM to transfer the detailed requirements and designs developed for the Garden Avenue facility and apply them to the Savannah Oaks Drive facility where possible, including the dedicated space for Energy+ and the shared facilities space. This work has resulted in a Class D estimate for the new construction and refurbishment elements of the project, and draft designs for the new build portions, as well as the allocation of space for the existing buildings.

Space Requirements

In September 2017, as part of the design work, a space needs analysis was conducted for Energy+'s requirements at the joint facility with BPI. This analysis identified the need for the following:

Administration

- Two offices
- A meeting room
- A lunch room

Operations

- A locker room
- Parking for eight large trucks (two more than the Dundas Street facility)
- Indoor parking for smaller operations vehicles

4.4.2.2.6. Options Analysis

Options Evaluated

Option 1: Renovate or Rebuild existing Dundas Street Facility

The Dundas Street Facility was constructed initially in 1973 and requires refurbishing. It was originally built to primarily house administrative office space, with limited operational capacity. With the relocation and centralization of administrative staff following the acquisition of BCP, the office space is currently vacant and underutilized, whereas the operations space is over-crowded. Over the next ten years, Energy+ expects an increase in construction activity in the Brant County service territory due to: i) customer growth; and ii) a renewal program as a result of aging infrastructure. In order to fully utilize the existing space, the building would need to be substantially renovated and reconfigured. This would include increasing the space required for operations, vehicles and inventory, which the current building was not designed to house. Building a new facility on this land would incur a similar cost per square foot relative to Option 3 below (new facility), but Energy+ would not generate the same benefits associated with shared services with BPI and would not benefit from the proceeds from the sale of the Dundas Street property.

In 2018, Martin Simmons Architects prepared a Condition Study of the Paris facility and concluded that due to the buildings age, configuration and construction, the building cannot be upgraded, modified or expanded to meet current and future functional or performance expectations. As well due to the constricted location of the building on the site, no possibility exists to enlarge the building to accommodate needed program elements.

The land and building at the Dundas Street Facility were sold on April 3, 2018 for $1.5 million in a sale-leaseback transaction. Energy+ entered into a flexible lease that enables it to vacate the property within five years of the closing date.

<u>Option 2: Lease Shared Space with BPI</u>

In early 2017, Energy+ and BPI began a formal conversation to explore the potential opportunity to share operating and administrative facilities. The relocation of BPI's operating and administrative facilities was discussed in BPI's 2017 Cost of Service Rate Application (EB-2016-0058), although the specific location was determined after its application was approved.

The idea of shared facilities between Energy+ and BPI was explored in light of the following:

- The expected customer growth in the City of Brantford in future years, combined with the proposed annexation of the municipal boundaries between the County of Brant and the City of Brantford.
- The Savannah Oaks Drive facility is approximately 5km from the current facility on Dundas Street. The new location will have minimal operational impact and will enable Energy+ to service the anticipated customer growth, as well as service the existing customer base in the Brant County service territory.
- A desire by both utilities to provide an innovative approach to reducing costs (both operating and capital costs) in the future by sharing the costs for facilities and services. This aligns to the outcomes expected under the OEB's *Renewed Regulatory Framework* of customer

focus, operational effectiveness and financial performance. In addition, such an approach aligns to the Long-term Energy Plan with respect to encouraging partnerships between LDCs and efficiencies.

The base rent cost to lease the approximately 14,229 square feet of exclusive use administrative and vehicle storage space is currently estimated to be $23/s.f./year. The price is subject to further updates as the actual costs incurred will inform the final lease rate upon completing construction. Energy+ would also have access to up to 10,316 square feet of shared warehousing and repair garage space, and 3,389 square feet of the common elements of the facility. These components would be paid through license fees of approximately $25/s.f./year. Energy+ would enter into a 20-year lease with BPI, with the option to extend the lease term up to an additional 20 years.

The lease rates for the exclusive space will recover the capital cost of the exclusive facilities which shall include Energy+'s proportionate share of the capital cost of all infrastructure servicing the exclusive and shared facilities (such as HVAC systems and equipment, backup generators, etc.). The methodology used to establish base rent to recover the cost of capital will be in keeping with the OEB's determination of revenue requirement using the parameters of BPI's 2017 COS Decision. The base rent calculation includes the recovery of amortization, PILS and return on invested capital.

The base rent estimate of $23/s.f./year has been calculated to recover: i) the allocated portion of the purchase price of the facility less proceeds from land severances; and ii) the design and construction costs associated with preparing the facility for its intended use based on a Class D estimate. The allocated capital would include the portion of the project that relates to Energy+'s exclusive use, and the leasehold improvements made to Energy+'s exclusive facilities during construction. A Class D estimate is associated with an accuracy of +/- 30%. With future updates to designs and cost estimates planned, the final base rent calculation will be available after construction is complete. Appendix F Exhibit IV – Allocation of Capital Costs provides a breakdown the capital costs allocated to Energy+.

The rate was arrived at by determining the annuity payments required to recover the capital costs over the 41-year useful life of the assets, discounted at BPI's approved 2017 cost of capital rate grossed up for PILS, and dividing by the square footage.

A similar approach has been applied to the estimated license fee of $25/s.f./year. Appendix F Exhibit V – Calculation of Lease Rates provides the detailed rate calculations.

<u>Option 3: Acquire/Lease New Space in Brant County</u>

As described above, Energy+ entered into formal discussions with BPI in early 2017 to explore the potential for the two utilities to share operating facilities. Throughout these discussions, BPI and Energy+ reviewed various available alternatives with respect to leasing facilities, acquiring an existing building and acquiring vacant land in Brant County and the City of Brantford. In considering this option, Energy+ was also able to leverage the detailed work completed by BPI.

In early 2015, BPI engaged CBRE to undertake a thorough review of facilities site options in the Brantford area. By late 2016, CBRE had identified 14 existing industrial/office buildings for sale and/or lease and 22 greenfield, new construction and brownfield properties. In total BPI investigated:

- 20 existing industrial/office buildings;
- 19 greenfield and brownfield properties'
- 16 “off-market” investigations of suitable properties which were occupied or not available for sale.

The price per square foot for existing buildings for sale at that time was $34 and $162 and lease rates ranging between $3.00-$14.00 per square foot.

BPI initially focused on options to purchase and refurbish existing buildings, due to the relative timeliness versus a greenfield new build option and expected cost savings. The Savannah Oaks Drive property was identified as closest to meeting the key requirements but would require additional construction to be made suitable to BPI’s needs. BPI pursued the purchase of Savannah Oaks Drive beginning in February 2015 but was not able to conclude negotiations.

In November 2016, CBRE identified the Garden Avenue property which had certain advantages, including the pricing and location of the property. The Garden Avenue property is in a low-congestion area close to Highway 403, that would allow for quick travel times throughout the service area.

The land was acquired by BPI in 2017 for $1.7M. As outlined in BPI’s 2020 ICM, the total estimated cost for the Garden Ave. facility was $30.7MM ($29MM construction and soft costs and $1.7MM). The allocated costs to Energy+ Inc. for the dedicated space was approximately $6.8MM, based on the Class C estimate.

The following is an excerpt from BPI's 2020 IRM Application[11], which summarizes the allocation of space and costs for the Garden Ave. facility:

ICM Table 10-B Garden Ave. Allocation of Space & Costs

	Square Feet	Cost	
BPI	37,297	$	16,932,784
Energy+	14,747	$	6,771,987
Shared - BPI and Energy+	9,537	$	5,542,834
Affiliates	2,906	$	1,469,585
Total Space	**64,487**	**$**	**30,717,190**

Based on the Class C estimate prepared for Garden Ave, the dedicated space for Energy+ would cost approximately $6.8MM for a new build, compared to the $4.4MM for the Savannah Oaks facility.

Summary of Options

A summary of the three options is presented in Table 19: Summary of Options. The gain on sale of the Dundas St. facility is excluded from the analysis.

Energy+ believes that the best option for the Operations facility to service the Brant County service territory is the Savannah Oaks Drive shared facility with BPI.

[11] EB-2019-0022, 2020 ICM, Page 22 of 40.

Table 19: Option Summary – Brant County

Option	Description	Building Construction Cost	Building Renovation/ Acquisition/Lease Cost	Notes
1	Renovate or Rebuild Existing Dundas Street Facility	Not Applicable.	Not Applicable.	In need of substantial refurbishment and redesign; not suited to meet current and projected operational needs. Property sold on April 3, 2018.
2	Lease Shared Space with BPI (Savannah Oaks Drive)	$4,395,862 (Capital Lease)	20-year lease for approximately 14,230 sq ft of exclusive use space for $23/sq ft/yr and license for up to 13,488 sq ft of shared and common space currently estimated at $25/ sq ft/yr	**Preferred Option.**
3	Acquire/Lease New Space (Garden Avenue or Alternative)	$6,771,987 (Capital Lease).	20-year lease for approximately 14,747 sq ft of exclusive use space for $35/sq ft/yr and license for up to 4,768 sq ft of shared and common space currently estimated at $43/ sq ft/yr	High costs of construction make this option unfavourable relative to the Savannah Oaks Drive option.

4.4.2.3. Summary of Energy+ Overall Facilities Plan

Table 20: Proposed Facilities Space summarizes the proposed space for each building and the primary use for each building based on Energy+'s overall facilities plan.

Table 20: Proposed Facilities Space

	Current State			Future State		
Location	**Administration Sq. Ft.**	**Operations Sq. Ft.**	**Total Sq. Ft.**	**Administration Sq. Ft.**	**Operations Sq. Ft.**	**Total Sq. Ft.**
Bishop St.	13,182	39,918	53,100	13,182	39,918	53,100
Thompson Dr.	5,147	-	5,147	-	-	-
Southworks	-	-	-	21,892	-	21,892
Dundas St.	5,007	9,376	14,383	-	-	-
Shared Facilities with BPI - Exclusive Space			-	926	13,303	14,229
Shared Space with BPI					Up to 20,632 sq. ft of Warehouse/Repair Garage plus Outdoor Storage	
Total	23,336	49,294	72,630	36,000	53,221	89,221

Table 21: Land and Buildings – Capital and Operating Cost Summary summarizes the capital and lease costs related to the overall Facilities Plan.

Table 21: Land and Buildings – Capital and Operating Cost Summary

Site	Purchase / (Sale) / Capital Cost from Lease	Renovations	Operating Cost / (Savings)	Notes
Southworks	$1.00	$8,100,000* (exclusive of HST)	$150,000	Heritage building to be renovated; Annual cost for parking
Bishop Street	Not applicable.	$2,000,000	Not applicable.	Renovation of existing building
Thompson Drive	Not applicable.	Not applicable.	($77,205)	Lease to be terminated.
Savannah Oaks Drive	$4,396,000 (estimated capital cost for exclusive Energy+ space)	Not applicable.	$345,000 (annual rate for shared and common space)	Exclusive Energy+ space (Capital) plus shared services space (Operating) with BPI

* In Energy+'s Final Decision and Rate Order (EB-2018-0028), the Board approved an ACM amount of $6.5MM for Southworks. Energy+ has filed a Motion to Review the ACM Decision. The costs included in the table for Southworks represent the amount requested by Energy+ for approval, as it represents the costs derived from a Class C estimate.

4.4.2.4. Benchmarking

In Table 22: Cost and Utilization Comparison to Other Distributors, the cost and utilization for Energy+'s overall Facilities Plan is presented, along with the cost and utilization for each of the facilities in the Energy+ service territory, and other LDC comparators.

While Energy+ is seeking approval in this Application for the capital expenditures related to the dedicated operations space with respect to the Shared Facilities with BPI, Energy+ has developed a Facilities Plan that addresses the long-term facility needs of the utility to service the customers in the Cambridge and North Dumfries and Brant County service territories.

Energy+ has taken an approach to its Facilities Plan that results in a lower overall capital expenditure plan for the replacement and upgrading of its entire facilities than would otherwise been the case if Energy+ had sought to build a brand-new administration and operations centre, as was originally considered. As outlined in Energy+'s Facilities Plan (EB-2018-0028), the estimated cost of this option was approximately $32MM (based on estimates developed in 2014).

As such, Energy+ believes that the cost and utilization comparison that should be considered is the combined cost of Energy+'s Facilities Plan.

The comparison demonstrates that Energy+ is proposing an overall Facilities Plan that is appropriately sized for its work force. Energy+'s proposal results in 681 sq.ft./FTE, which is lower than the comparators that range between 840 sq. ft./FTE and 1,494.

In terms of costs, Energy+'s Facilities Plan results in a capital cost per FTE of $110,656. The comparators range between $203,655 and $272,000.

With regards to capital cost/sq.ft., the Energy+ Facilities Plan results in a capital cost/sq.ft. of $162.47, which is less than all of the comparators with the sole exception of Milton Hydro.

Table 22: Cost and Utilization Comparison to Other Distributors

LDC	Energy+ (Southworks, Bishop Street & Savannah Oaks Dr. Combined)	Energy+ (Southworks)	Energy+ (Savannah Oaks)	Energy+ (Bishop St.)	Waterloo North Hydro Inc	InnPower	Milton Hydro Distribution Inc	PUC Distribution Inc.
OEB Docket	EB-2018-0028/ EB-2019-0031				EB-2015-0108 EB-2010-0144	EB-2014-0086	EB-2015-0089	EB- 2012-0162
Year of Occupancy	2020/2022/2024	2022	2020	2024	2011	2015	2015	2012
Functions	Administration & Operations	Administration	Operations	Operations	Administration & Operations	Administration & Operations	Administration & Operations	Administration & Operations
Type of Project	Purchase/ Refurbish	Purchase/ Refurbish	Refurbish	Refurbish	Custom Build	Custom Build	Purchase/ Refurbish	New Build
Capital Cost	$14,496,000	$8,100,000	$4,396,000	$2,000,000	$26,682,000	$11,141,210	$12,524,798	$23,000,000
Class of Estimate		Class C	Class D	Not Applicable				
Class Estimate %		+20%	+30%					
Square Footage	89,221	21,892	14,229	53,100	105,000	36,172	91,872	110,382
FTEs	131	67	13	51	125	41	61.5	87
Square Foot per FTE	681	327	1,095	1,041	840	882	1,494	1,269
Capital Cost per FTE	$110,656	$120,896	$338,154	$39,216	$213,456	$271,737	$203,655	$264,368
Capital Cost/Square Foot	$162.47	$370.00	$308.95	$37.66	$254.11	$308.01	$136.33	$208.37

NOTE: Capital Costs and Capital Cost/Square Foot for LDC comparisons have not been adjusted for inflation.

4.4.2.5. Gain on Sale of Paris Property

Table 23: Computation of Gain on Sale of Paris Property provides the computation of the gain based on the actual transaction that occurred in 2018:

Table 23: Computation of Gain on Sale of Paris Property

Computation of Gain on Sale of Property				
Proceeds from Sale of Property			$	1,500,000
Less: Transaction Costs				
Realtor and Legal Fees				(43,050)
Fair value increase paid by former CND on Acquisition		(555,416)		
Less: Acc. Amortization on Fair Value to April 3, 2018		75,835		(479,581)
Net Proceeds				977,369
	Original Cost	**Acc. Amort.**		**NBV**
Regulatory Net book value, as at April 3, 2018				
Land	87,795	-		87,795
Building	550,700	253,271		297,429
Total	638,495	253,271		385,224
Gain on Sale of Property			$	592,145
Estimate of Total Tax Cost on Sale				(189,338)
Net Gain on Sale of Property			$	402,807

Notes:

The “Fair Value Increase Paid by Former CND on Acquisition” represents the fair value increase over the book value that was paid by the former CND. The fair value of the property was determined based on a market valuation report. It is appropriate to reduce the overall proceeds from the sale of the property by this amount since the gain is simply a calculation of the total costs incurred in purchasing the land and building (which in this case includes the premium paid), compared to the net proceeds received for the sale of the property. This is the basis upon which tax is calculated and is the basis upon which Energy+ has calculated the amount to be returned to its customers.

The “Estimate of Total Tax Cost on Sale” was calculated using an estimate of the detailed tax calculations that would occur with this transaction, including the appropriate capital gain tax computation.

Energy+ is proposing to dispose of the gain on sale realized on the Paris facility through a Gain on Sale Rate Rider for each customer class. Energy+ is requesting that the disposition of the Gain on Sale Rate Rider be disposed over a three-year period (January 1, 2020 to December 31, 2022). Energy+ submits that this proposal is aligned with the period of the ICM Rate Rider and will to help to mitigate the incremental revenue, and associated bill impacts, to customers related to the shared facility with BPI.

4.4.2.6. ICM Conclusion

Energy + is seeking approval for the planned 2020 capital investment of $4.4MM with respect to its shared facility with BPI, as requested as part of this IRM Application. Energy+ also proposes to dispose of the gain on sale realized on the Paris facility through a Gain on Sale Rate Rider for each customer class.

4.4.3. Treatment of Costs for 'Eligible Investments'

E+ is not applying for any recovery of 'eligible investments' related to renewable energy generations costs.

4.4.4. Conservation and Demand Management Costs for Distributors

Conservation and Demand Management Costs are not included in the distribution rates for E+ and are not included in this application.

4.4.5. Off-Ramps

Energy+ achieved a Regulatory Return on Equity of 9.49% in 2016, as shown in E+'s 2016 published Scorecard. This amount is within +/- 300 basis points, of both the Board-approved Return on Equity of 9.36%, determined in the CND 2014 Cost of Service Rate Application (EB-2013-0116), and the Board-approved Return on Equity of 9.58%, as determined in the former BCP 2011 Cost of Service Rate Application (EB-2010-0125).

5. Customer Bill Impacts

Table 24: Distribution and Total Bill Impact summarizes the bill impacts by customer class for E+ customers, at varying consumption and demand levels, on the proposed Distribution charges (fixed and variable) and on the Total Bill (before HST).

Table 24: Distribution and Total Bill Impact

Rate Class	kWh	kW	Distribution (Fixed & Volumetric)				Total Bill (Excluding HST)			
			Current	Proposed	$ Change	% Impact	Current	Proposed	$ Change	% Impact
Residential	750		$ 28.03	$ 28.07	$ 0.04	0.1%	$ 103.38	$ 104.59	$ 1.21	1.2%
Residential	320		$ 26.91	$ 28.07	$ 1.16	4.3%	$ 61.41	$ 62.32	$ 0.91	1.5%
GS<50 kW	2,000		$ 46.96	$ 47.52	$ 0.56	1.2%	$ 240.37	$ 247.30	$ 6.94	2.9%
GS> 50 to 999 kW	20,000	60	$ 329.40	$ 332.86	$ 3.45	1.0%	$ 3,103.04	$ 2,962.82	$ (140.21)	-4.5%
GS> 1,000 to 4,999 kW	800,000	2,000	$ 8,492.41	$ 8,581.49	$ 89.08	1.0%	$ 109,838.30	$ 108,690.66	$ (1,147.64)	-1.0%
Large Use	6,600,000	16,000	$ 35,656.07	$ 36,030.32	$ 374.25	1.0%	$ 894,040.25	$ 861,663.56	$ (32,376.69)	-3.6%
Unmetered Scattered Load	100		$ 7.25	$ 7.33	$ 0.08	1.1%	$ 16.86	$ 17.59	$ 0.73	4.3%
Street Lighting	400,000	700	$ 11,755.18	$ 11,878.61	$ 123.43	1.1%	$ 74,875.56	$ 61,767.75	$ (13,107.81)	-17.5%
Sentinel Lighting	10,000	29	$ 1,224.08	$ 1,236.94	$ 12.85	1.1%	$ 2,560.85	$ 2,353.00	$ (207.85)	-8.1%
Embedded Distributor - Hydro One CND	1,382,000	2,574	$ 5,431.65	$ 5,488.80	$ 57.14	1.1%	$ 177,061.64	$ 175,498.03	$ (1,563.61)	-0.9%
Embedded Distributor - Waterloo North Hydro		8,280	$ 13,563.47	$ 13,705.88	$ 142.42	1.0%	$ 28,619.24	$ 46,692.59	$ 18,073.34	63.2%
Embedded Distributor - Brantford	50,000	27	$ 253.14	$ 255.80	$ 2.66	1.0%	$ 6,400.18	$ 6,200.85	$ (199.33)	-3.1%
Embedded Distributor - Hydro One #1	1,300,000	2,340	$ 2,833.10	$ 2,862.84	$ 29.75	1.0%	$ 161,794.98	$ 159,642.21	$ (2,152.78)	-1.3%
Embedded Distributor - Hydro One #2	1,990,000	4,050	$ 69.79	$ 70.52	$ 0.73	1.0%	$ 230,880.29	$ 229,099.37	$ (1,780.92)	-0.8%

The detailed Customer Bill Impacts by class, category, and varying consumption and demand levels are computed in Tab 20 of the 2020 IRM Rate Generator Model and are included in Appendix D.

6. Conclusion

Energy+ requests approval for an Order or Orders approving or fixing just and reasonable rates and other service charges for the distribution of electricity effective January 1, 2020.

All of which is respectfully submitted this 26th day of August 2019.