Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, Ontario M4P 1E4
Boardsec@oeb.ca

August 12, 2019

Sent via RESS and Courier

Dear Ms. Walli,

RE: EB-2019-0022 – Filing with Delayed with Global Adjustment Work Form

BPI is pleased to provide the attached Application for rates effective January 1, 2020. The rate proposals include an adjustment to BPI's distribution rates consistent with the OEB's IRM methodology, as well as a claim for incremental capital associated with its Facility Relocation project. The Application does not include any proposed Deferral and Variance Account Rate Riders as a result of the materiality threshold for disposition not being met. As such, BPI is not proposing to make any final adjustments to the DVA balances.

BPI is in the process of implementing the Accounting Guidance issued by the OEB with respect to accounts 1588 and 1589 and has identified some related adjustments required to the accounts, which are reflected in the DVA continuity schedule. The implementation of the new 1588/1589 processes had an associated deadline of August 31, 2019. At this time BPI is not able to reconcile the Global Adjustment Variance Workform within the +/- 1% level that is required. BPI continues to work to address this reconciliation and commits to submitting the reconciled form and any necessary updates (should they exist) at a future date within the coming weeks.

Since the disposition of DVAs is not being proposed in this Application, BPI requests that the OEB consider the rate proposals included in the Application despite the delayed Global Adjustment Reconciliation work form and responses to associated questions.

Please do not hesitate to contact me with any questions,

Original Signed By

Oana Stefan
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BRANTFORD POWER INC

2020 INCENTIVE REGULATION MECHANISM

DISTRIBUTION RATE APPLICATION

EB-2019-0022

For Rates Effective January 1, 2020

IN THE MATTER OF the *Ontario Energy Board Act, 1998,* S.O. 1998, c.15, (Scheduled B);

AND IN THE MATTER OF an Application by Brantford Power, 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.

Contents

Contact Information

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1.0 Manager's Summary

1.1 Introduction

In preparing this Application, Brantford Power Inc. ("BPI") has adhered to the *Filing Requirements for Distribution Rate Applications- 2019 Edition for 2020 Rate Applications* (the "Filing Requirements")- Chapter 1 (Overview) and Chapter 3 (Incentive Rate-Setting Applications), as updated by the Ontario Energy Board ("OEB") on July 15, 2019.

BPI has chosen to file its 2020 Distribution Rate Application under the Price Cap Incentive Rate adjustment option.

The persons affected by this Application are the distribution ratepayers of BPI.

1.2 Proposed Rate Adjustments for January 1, 2020

In accordance with the OEB's letter of July 15, 2019, BPI is in Tranche 1 of Price Cap Incentive Rate-setting ("IRM") applicants as it will be filing for rates effective January 1 for the 2020 rate year. BPI has therefore prepared and submitted its Application with the filing deadline of August 12, 2019.

BPI is requesting the following rate adjustments in this proceeding.

1. Continuation of the current customer rate classes approved in EB-2016-0058, including the continuation of the Standby Customer Class on an interim basis;

2. Approval of the price cap adjustment as calculated in Tab 16 of the completed 2020 IRM Rate Generator model, included as IRM Attachment B and summarized in Table 1.5.1-B below;

3. Approval of the adjustments to BPI's retail transmission service rates (RTSRs) as calculated in Tabs 10 to 15 of the 2020 IRM Rate Generator Model (IRM Attachment B), and summarized in Table 1.5.5-B below;

5. Establishment of a Foregone Rate Rider, only in the event that there is an unforeseen delay in the OEB's Decision and Rate Order which results in a delay to BPI's implementation of rates beyond January 1, 2020.

6. Continuation of the Specific Service Charges, Primary Metering Allowance and Transformer Allowances approved in EB-2016-0058.

7. Approval of the inflationary adjustments for Access to Poles and Retail Service Charges calculated on tab 17 of the completed 2020 IRM Rate Generator Model

8. Continuation of the Rate Rider for Smart Metering Entity Charge, as approved in EB-2017-0290 and expressed in the OEB's letter of March 1, 2018, which expires December 21, 2022.

9. Inclusion of the most recently OEB-Approved Regulatory Charges.

A Certification of Evidence signed by BPI's Chief Financial Officer and Vice President of Corporate Services is included as IRM Attachment C, as required by the Filing Guidelines, Chapter 1.

A PDF schedule of BPI's current rates- the Rate Order from its 2019 IRM Application (EB-2018-0020), is included as IRM Attachment D. BPI confirms that the rates included in Tab 2- Current Tariff Schedule of the 2020 IRM Rate Generator Model are consistent with the current (2019) rate schedule.

A schedule of BPI's proposed rates is enclosed as IRM Attachment E.

IRM Attachment F is a compendium of supporting evidence used in the completion of the models, including section 2.1.5 of BPI's 2018 RRR Statistics, filed in April 2019 as well as excerpts from the Settlement Agreement underpinning BPI's current rates.

The following is a list of attachments to this document, marked with ("excel") if the corresponding excel model is being submitted:

- IRM Attachment A: ICM Application and ICM Appendixes (ICM model in excel)
- IRM Attachment B: Completed 2020 IRM Rate Generator Model (excel);
- IRM Attachment C: Certification of Evidence;
- IRM Attachment D: Most Recent Tariff of Rates (2019 Rate Order EB-2018-0020);
- IRM Attachment E: Proposed Tariff of Rates
- IRM Attachment F: Supporting RRR and Rate Order Excerpts;
- IRM Attachment G: KPMG Substantively Enacted Tax as at June 30, 2019
- IRM Attachment H: 1595 Analysis Work Form
- IRM Attachment I: Completed 2020 IRM Application Completion Checklist

Consistent with the Filing Requirements, section 3.1.2, all attachments have been provided in text-searchable PDF format where possible. Excel Models have been provided through the RESS.

1.3 Electronic Models- Accuracy of Calculations and Data

BPI has used the 2020 IRM Rate Generator, issued by the OEB on July 5, 2019 to support its application. The model was pre-populated with BPI's most recent tariff of rates and charges, load and customer data for 2018 from its April 2019 RRR filing, and Group 1 DVA balances as at December 31, 2018 from the same RRR filing.

BPI has reviewed the auto-populated entries in column BV of Tab 3.Continuity Schedule of the 2020 IRM Rate Setting Model and confirms they are consistent with those filed in section 2.1.7 of BPI's April 2019 RRR filing.

BPI has also reviewed the 2018 RRR statistics populated into Tab 4. Billing Determinants for Deferral Variance Accounts, and confirms these statistics are accurate and are the appropriate billing determinants for the allocation of the Group 1 Variance Accounts.

BPI also confirms the rates in Tab 2.Current Tariff Schedule are consistent with those in BPI's most recent Tariff of Rates, being the rates in its 2019 Rate Order in EB-2018-0020 (IRM Attachment D).

1.4 Summary of Bill Impacts

The following Table 1.4 summarizes the bill impacts arising from the requested rate adjustments in this Application. Consistent with the Filing Guidelines Section 3.1.3, the commodity rates and regulatory charges have been held constant to the regulated price plan rates at the time the rate generator model was published (*Regulated Price Plan Prices and the Global Adjustment Modifier for the Period May 1, 2019 to October 31, 2019*, released April 17, 2019). The typical residential consumption used is 750 kWh, consistent with the *Report of the Board- Defining Ontario's Typical Residential Customer*.

A discussion of BPI's proposal to not dispose of Group 1 DVAs is included in section 1.5.6 below. Table 1.4 represents the calculated bill impacts including the DVA disposition. These bill impacts are consistent with those in IRM Attachment B.

Table 1.4: Summary of Proposed Bill Impacts *not including* Group 1 DVA Disposition below

RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	Units	Sub-Total A (excluding pass through)		Sub-Total B - Distribution (includes Sub-Total A)		Sub-Total C - Delivery (including Sub-Total B)		Total Bill	
		$	%	$	%	$	%	$	%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ 1.59	6.6%	$ 3.24	13.1%	$ 3.70	10.4%	$ 3.88	3.7%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kWh	$ 2.66	5.5%	$ 7.06	14.1%	$ 8.09	10.7%	$ 8.50	3.3%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 59.87	6.2%	$ 558.02	117.7%	$ 598.02	39.0%	$ 675.76	4.5%
EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$1,435.82	5.9%	$(1,870.18)	-6.7%	$ 49.82	0.1%	$ 56.30	0.0%
SENTINEL LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 0.67	2.7%	$ 1.55	6.5%	$ 1.70	6.1%	$ 1.92	4.9%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$1,624.67	8.1%	$ 4,831.31	28.7%	$ 5,119.92	20.9%	$ 5,785.51	5.2%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - Non-RPP (Other)	kWh	$ 1.33	8.5%	$ 2.00	12.5%	$ 2.12	11.3%	$ 2.39	4.2%
STANDBY POWER SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ -	0.0%	$ -	0.0%	$ -	0.0%	$ -	0.0%

1.5 Detailed Explanation of Rate Adjustments

1.5.1 Annual Adjustment Mechanism

BPI has chosen the Price Cap Incentive Mechanism as its rate-setting method. Under this method, prices are adjusted annually based on the OEB-approved formula which incorporates the OEB's expectations of efficiency and productivity gains. The rate adjustment is calculated based on an annual rate of inflation minus an "X-Factor" adjustment. The X Factor is made up of two components: a sector wide productivity factor and a LDC-specific stretch factor.

The Inflation factor used in the Rate Generator Model (Tab 16 Revenue to Cost GDP IPI) is a placeholder of 1.20%, which is the inflation factor for 2018 Price Cap IR rate-setting released by the OEB on November 23, 2017. As discussed in the Filing Requirements, Section 3.2.1, BPI requests that OEB Staff update the inflation factor for 2020 rates prior to the OEB's Decision and Order in this Application.

The X Factor used in Tab 16 is made up of total factor productivity for the industry of 0%, and a BPI-specific stretch factor of 0.3%. Stretch factor assignments are updated annually, and BPI has used the stretch factor assigned to it for 2019 rate making as a placeholder. As with the Inflation Factor, BPI expects OEB Staff will update the Annual Adjustment Mechanism in Tab 16 of the Rate Generator when updated Incentive Ratemaking Parameters are released for 2020.

Table 1.5.1-A: Price Cap IR Parameters

Item	Value	Source	Notes
Inflation Factor	**1.20%**	*2018 IR Rate Setting Parameters*	Placeholder
Productivity Factor	0	*Report of the Board EB-2010-0379*	Final
Stretch Factor (Group III)	0.30%	*2018 IR Rate Setting Parameters*	Placeholder
X Factor	**0.30%**	*Calc.*	To be updated
Annual IR Adjustment	**0.90%**	*Calc.*	To be updated

Consistent with the Filing Requirements, this adjustment of 0.90% has been applied only to the Monthly Service Charge ("Monthly Fixed Charge" or "Monthly Distribution Rate") and Distribution Volumetric Rate ("Variable Rate") for each customer class (excluding the MicroFIT Service Charge). This adjustment does not apply to any of the items listed on Page 7 of the Filing Requirements, with the exception of the charge for Access to Poles(OEB Report in EB-2015-0304, Released March 22, 2018) and the Retail Service Charges (OEB Report in EB-2015-0304, Released November 29, 2018).

Table 1.5.1-B: Distribution Rate Adjustment for Price Cap IR

Rate Class	Current Charges		Distribution Rate Adjustment (*placeholder*)	Proposed	
	Monthly Service Charge	Volumetric Charge		Monthly Service Charge	Volumetric Charge
RESIDENTIAL	$ 23.50	0.0000	0.90%	$ 23.71	$ -
GENERAL SERVICE LESS THAN 50 KW	$ 30.77	0.0081	0.90%	$ 31.05	$ 0.0082
GENERAL SERVICE 50 to 4,999 kW	$ 236.93	2.8643	0.90%	$ 239.06	$ 2.8901
EMBEDDED DISTRIBUTOR	$ 362.56	2.0121	0.90%	$ 365.82	$ 2.0302
SENTINEL LIGHTING	$ 4.24	20.3000	0.90%	$ 4.28	$ 20.4827
STREET LIGHTING	$ 1.45	6.0789	0.90%	$ 1.46	$ 6.1336
UNMETERED SCATTERED LOAD	$ 13.12	0.0091	0.90%	$ 13.24	$ 0.0092
STANDBY POWER	$ -	1.7389	0.90%	$ -	$ 1.7546
MICROFIT	$ 5.40		0.00%	$ 5.40	$ -

1.5.2 Revenue to Cost Ratio Adjustments

During Cost of Service Rate Setting, the OEB may require, through a Decision and Order, that an LDC adjust its revenue to cost ratios during the Incentive Rate-Setting years in order to phase in an adjustment. BPI did not need any such phase-in as a result of its 2017 Cost of Service Decision and Order (EB-2016-0058). As a result, BPI has not completed the OEB's revenue to cost ratio adjustment work form. Therefore, no rate design adjustments have been applied.

1.5.3 Rate Design for Residential Electricity Customers

Consistent with the OEB's Residential Rate Design Policy, BPI has now fully transitioned its residential distribution rates to a fully fixed monthly distribution charge. BPI began this transition in 2016, and implemented the transition over a period of four years. BPI has made all 4 of such adjustments in its previous annual Applications completing the final annual increase to the residential fixed distribution rate (and corresponding decrease in the volumetric residential distribution rate) in its 2019 rates. BPI understands that, since the transition to fully fixed residential rates is complete, the additional mitigation threshold tests are not applicable. These additional threshold tests, specific to the residential rate design policy, investigated whether the monthly fixed increased by more than $4 and also required the calculation of the residential bill impact at the 10^{th} percentile of consumption.

Consistent with section 3.2.3 of the Filing Requirements, BPI has calculated residential class charges related to pass-through or energy related costs as variable charges. BPI's proposed rate riders for incremental capital have been calculated on a monthly charge basis for the Residential class, as these rate riders are associated with the distribution of electricity.

1.5.4 General Mitigation Considerations

As discussed in section 3.2.3 of the Filing Requirements, the OEB requires distributors to propose a mitigation plan if the total bill impact for any customer class exceeds 10%. The proposed bill impacts for each customer segment presented in Table 1.4 are well below the 10% mitigation threshold and therefore BPI has not proposed any mitigation plans.

1.5.5 Electricity Distribution Retail Transmission Service Rates (RTSRs)

Electricity Distributors are charged the Ontario Uniform Transmission Rates (UTRs) at the wholesale level and subsequently pass these charges onto their distribution customers through RTSRs at the retail level. For each distribution rate class, there are two RTSRs- one for network and one for connection. The RTSR-Network Service Rate recovers the UTR Wholesale Network Service charge, and the RTSR Line and Transformation Connection Service Rate recovers the UTRs Wholesale Line Connection and Transformation Connection charges.

In preparing its Application, BPI consulted and followed the OEB's *Guideline G-2008-0001: Electricity Distribution Retail Transmission Service Rates (RTSR), Revision 4.0, issued June 28, 2012.*

The RTSR section of the 2020 IRM Rate Generator Model (Tabs 10 to 15) calculates adjusted RTSR rates based on historical retail and wholesale transmission volumes, adjusted for forecast wholesale transmission rates.

BPI is primarily charged for wholesale transmission rates by the IESO on the basis of UTRs. Additionally, BPI receives a small volume of electricity through an embedded point to Energy+. BPI has included the transmission volumes and transmission charges from Energy+ as a Host Distributor, for which BPI will pay the Embedded Distributor Service Class - Brantford RTSRs, which is a service classification specific to BPI.

Consistent with Section 3.2.4 of the Filing Guidelines, BPI requests that OEB staff adjust the proposed 2020 RTSRs if the OEB approves updated 2020 UTRs or 2020 Energy+ Rates prior to its Decision and Order in this Application.

BPI has populated the following rates in Tab 11. RTSR- UTRs & Sub-Tx:

1.5.5-A: Summary of Wholesale Transmission Rates Used

IESO UTRS		**2018**	**2019 (Jan 1 - June 30)**	**2019 (July 1 - Dec 31)**	**2020**
Network Service Rate		3.61	3.71	3.83	3.71
Line Connection Service Rate		0.95	0.94	0.96	0.94
Transformation Connection Service Rate		2.34	2.25	2.30	2.25
		EB-2017-0359	*EB-2018-0326*	*EB-2019-0164*	*(placeholder)*
Energy+ RTSRs		**2018**	**2019**		**2020**
Network Service Rate		2.2264	2.6625		2.6625
Both Line and Transformation Connection Service Rate		1.1812	1.6731		1.6731
		EB-2017-0030	*EB-2018-0028*		*(placeholder)*

The resultant proposed RTSRs by class are set out below:

Table 1.5.5-B: Summary of Proposed RTSRs

Rate Class	Unit	Existing RTSR- Network		Proposed RTSR-Network	
Residential Service Classification	$/kWh	$	0.0079	$	0.0083
General Service Less Than 50 kW Service Classification	$/kWh	$	0.0070	$	0.0073
General Service 50 To 4,999 kW Service Classification	$/kW	$	2.4118	$	2.5207
Embedded Distributor Service Classification	$/kW	$	2.4118	$	2.5207
Sentinel Lighting Service Classification	$/kW	$	2.2521	$	2.3537
Street Lighting Service Classification	$/kW	$	2.3204	$	2.4251
Unmetered Scattered Load Service Classification	$/kWh	$	0.0042	$	0.0044
Rate Class	**Unit**	**Existing RTSR-Connection**		**Proposed RTSR-Connection**	
Residential Service Classification	$/kWh	$	0.0061	$	0.0063
General Service Less Than 50 kW Service Classification	$/kWh	$	0.0054	$	0.0056
General Service 50 To 4,999 kW Service Classification	$/kW	$	1.8282	$	1.8793
Embedded Distributor Service Classification	$/kW	$	1.8282	$	1.8793
Sentinel Lighting Service Classification	$/kW	$	1.7075	$	1.7552
Street Lighting Service Classification	$/kW	$	1.6878	$	1.7350
Unmetered Scattered Load Service Classification	$/kWh	$	0.0054	$	0.0056

1.5.6 Review and Disposition of Group 1 Deferral and Variance Accounts ("DVAs")

General

BPI is eligible to dispose of Group 1 DVAs as at December 31, 2018, adjusted for dispositions during 2018, including projected interest on these balances from January 1, 2019 to December 31, 2019. BPI is not proposing to dispose of the balance in Group 1 DVAs or its LRAMVA account at this time, but intends to do so in a future IRM should the Group 1 total meet the disposition threshold or if the LRAMVA account balances be more substantial.

BPI has populated the Group 1 DVAs in Tab 3-Continuity Schedule of the 2020 Rate Generator Model with the balances up to 2018 year- end, as well as dispositions during 2018 and projected interest to the end of 2019. Group 1 balances for 2016 and 2017 were approved to be disposed of on an interim basis in 2019. As a result of the recent introduction of further accounting guidance with respect to RPP True Ups, BPI has identified adjustments required to the 2017 and 2018 balances. The same types of adjustments were not required for the 2016 balance. Table 1.5.6-A sets out the details of the Variance Account balances. BPI is not proposing to dispose of the balances in its Group 1 DVAs or in its LRAMVA Account at this time, but intends to do so in a future IRM and/or COS application, in accordance with the existing policies for the disposition of those accounts.

Table 1.5.6 – A: DVA Balances as at December 31, 2018 (and Projected Interest)

Account Descriptions	Account Number	Principle Eligible for Disposition	Interest (Including Projected Interest)	Total Eligible for Disposition	Disposition Proposed by BPI?
LV Variance Account	1550	$ -	$ -	$ -	
Smart Metering Entity Charge Variance Account	1551	$ (36,257)	$ (1,265)	$ (37,522)	no
RSVA - Wholesale Market Service Charge	1580	$ 312,719	$ 10,068	$ 322,788	no
Variance WMS – Sub-account CBR Class A	1580	$ -	$ -	$ -	no
Variance WMS – Sub-account CBR Class B	1580	$ (476,414)	$ (14,451)	$ (490,865)	no
RSVA - Retail Transmission Network Charge	1584	$ (70,770)	$ (2,524)	$ (73,294)	no
RSVA - Retail Transmission Connection Charge	1586	$ 415,183	$ 13,360	$ 428,543	no
RSVA - Power	1588	$ 1,025,870	$ 24,177	$ 1,050,047	no
RSVA - Global Adjustment	1589	$ (1,421,539)	$ (43,972)	$ (1,465,511)	no
Disposition and Recovery/Refund of Regulatory Balances (2016)	1595	$ 1,725	$ 59	$ 1,784	no
Disposition and Recovery/Refund of Regulatory Balances (2017)	1595	$ 11,254	$ 42,962	$ 54,216	no
Total Group 1 Balance Eligible for Disposition		$ (238,229)	$ 28,415	$ (209,815)	

Group 1 Accounts

The OEB's *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Report (EDDVAR)* establishes a threshold for the disposition of Group 1 accounts, to be calculated on the basis of the total of the Group 1 audited balances, divided by the total kWh of billing determinants.

The level of the threshold was set at an absolute value of $0.001 per kWh. If the threshold is exceeded, a distributor must explain why the balances in Group 1 should not be disposed. BPI has completed Tab 3-Continuity Schedule, and the resultant threshold calculation on Tab 4 Billing Det. for Def-Var is shown below in Table 1.5.6-B. The absolute value of the total Group 1 DVA claim is $0.0002/kWh, which is below the threshold of $0.001/kWh. As a result, the claim is not considered to meet the requirements for disposition.

Table 1.5.6-B: Threshold Test

Item	Value
Total Claim for Threshold Test (All Group 1 Accounts)	($209,815)
Threshold Test (Total claim per kWh)	**$ (0.0002)**

On February 21, 2019 the OEB released an Accounting Procedures Handbook Update titled Accounting Guidance Related to Commodity Pass-Through Accounts 1588 and 1589. In BPI's application for 2019 rates the OEB approved the disposition a credit balance of $3,110,355 on an interim basis, for 2016 and 2017 DVA balances.

BPI is in the process of implementing the accounting guidance for 2019, with full implementation expected by the requisite deadline of August 31, 2019. BPI had intended to implement the new processes for 2019 ahead of the filing of this Application, however difficulties with some of the necessary reports have caused some delay.

Instead, BPI has reviewed the account balances for 2016, 2017 (which have been disposed on an interim basis) and 2018 (which has not yet been disposed or reviewed) against the new accounting guidance. As BPI used a different CIS system in those years, the required reports were available for prior years. In reviewing the prior year balances, BPI discovered certain differences present in 2017 and 2018, related to the true up of final pricing on the difference between original estimates and final amounts of consumption. These final true ups were calculated correctly in 2016. BPI is not proposing to dispose of DVA balances as the sum of the Group 1 DVAs, when adjusted for the new accounting guidance, does not meet the threshold for disposition, per section 3.2.5 of the Filing Requirements.

Differences from RRR Trial Balance

BPI has confirmed the values populated in column BV of Tab 3 -Continuity Schedule are consistent with the RRR balances filed for December 31, 2018 in April of this year. A copy of the associated excerpt from BPI's RRR filing is included with IRM Attachment F. With the exception of small (+/- $2) differences due to rounding and the listing discussed below in this section, the balances for December 31, 2018 principal and interest balances calculated in the continuity schedule are consistent with those in column BV. Table 1.5.6-C shows a calculation of the variances between the continuity schedule amounts and the RRR balances populated in the model.

The Group 1 closing balances, as adjusted in the DVA schedule represent a total credit of $(3,314,952). These balances are further adjusted for Group 1 dispositions during 2019, and by projected interest during 2019 to arrive at the amount eligible to be claimed of $(209,815). Account 1595- 2018 is also excluded as a full year has not passed since this account balance was audited, consistent with the Filing Requirements (the account balance was audited in early 2019).

Table 1.5.6-C: Variances from RRR Trial Balance

Account Descriptions	Account Number	Closing Principle Amounts as of Dec 31, 2018	Closing Interest Amounts as of Dec 31, 2018	Total Closing Balance at December 31, 2018	2.1.7 RRR	Variance From RRR
LV Variance Account	1550	0	0	0	0	0
Smart Metering Entity Charge Variance Account	1551	(45,596)	(689)	(46,285)	(46,284)	1
RSVA - Wholesale Market Service Charge[5]	1580	(1,574,363)	(55,129)	(1,629,492)	(2,241,424)	**(611,932)**
Variance WMS – Sub-account CBR Class A[5]	1580	0	0	0	0	0
Variance WMS – Sub-account CBR Class B[5]	1580	(607,350)	(4,574)	(611,924)	(611,925)	(1)
RSVA - Retail Transmission Network Charge	1584	423,034	18,298	441,332	441,330	(2)
RSVA - Retail Transmission Connection Charge	1586	537,709	10,713	548,422	548,424	2
RSVA - Power[4]	1588	583,966	9,590	593,556	(1,017,829)	**(1,611,384)**
RSVA - Global Adjustment[4]	1589	(2,598,397)	(57,706)	(2,656,103)	(2,628,362)	**27,740**
Disposition and Recovery/Refund of Regulatory Balances (2009)[3]	1595	0	0	0		0
Disposition and Recovery/Refund of Regulatory Balances (2013)[3]	1595	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2014)[3]	1595	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2015)[3]	1595	(86)	37	(49)	(50)	(1)
Disposition and Recovery/Refund of Regulatory Balances (2016)[3]	1595	194,898	(203,180)	(8,282)	(8,282)	(0)
Disposition and Recovery/Refund of Regulatory Balances (2017)[3]	1595	11,254	42,709	53,963	53,963	0
Disposition and Recovery/Refund of Regulatory Balances (2018)[3]	1595	(7,598)	7,508	(90)	(91)	(1)
TOTAL GROUP 1 BALANCE		(3,082,529)	(232,423)	(3,314,952)	(5,510,530)	(2,195,578)
LRAM Variance Account	1568	0	0	0	368,002	**368,002**

As discussed in section 3.2.5 of the Filing Requirements, distributors must provide an explanation if the account balances in Tab 3. Continuity Schedule differ from the account balances reported through the RRR. BPI has explained each variance below.

Account 1580-RSVA Wholesale Market Service Charge, Variance: $(611,932)

Account 1580 is made up of three components, two of which capture the Capacity Based Recovery (CBR) Charge Variance (for each of Class A and Class B customers), and a third, "main" account which captures the variance in the remaining Wholesale Market Service Charge. In the RRR section 2.1.7-Trial Balance, Tab "Sub-Accounts", only the CBR sub-accounts are reported, while the full balance of the account (all three components) is reported on Tab "Group 1 Accounts". In the continuity schedule in Tab 3 of the 2020 IRM Rate Generator, BPI has populated only the non-CBR related WMS variance in the 1580-RSVA Wholesale Market Service Charge (a sub account balance of $(1,629,492) while the RRR value shows the full balance of 1580- RSVA Wholesale Market Service Charge (a total balance of $(2,241,424)). As expected the variance between the two values is equivalent to the value of the CBR sub-accounts, which is $(611,932) less a rounding error variance of $6.62. For clarity, the value of $(611,932) is essentially double counted in the 2.1.7 RRR column (column BU), as it is included both in RSVA- Wholesale Market Variance Accounts and in WMS Sub-Account Class B.

Account 1588 RSVA – Power, Variance: ($1,611,384)

The variance in account 1588 is made up of the adjustments outlined in table 1.5.6-D and discussed further below.

Table 1.5.6-D - 1588 Variance Calculation

	Impact on 1588	
Description	**Debit**	**Credit**
2017 Difference between BPI's true-up and the OEB accounting Guidance True-ups	666,597	
2018 Difference between BPI's true-up and the OEB accounting Guidance True-ups	917,045	
November 2018 Power Purchased True-up with the IESO	27,816	
December 2018 Power Purchased True-up with the IESO		(75)
	1,611,383	

BPI identified differences in the true up process historically used and the method included in the new 1588 & 1589 accounting guidance true-up process. The original true up calculation did not factor the difference between final pricing and RPP pricing on the consumption difference between estimated and actual consumption. Smaller variances resulted from the use of a calculated Global Adjustment (GA) rate per the OEB model and the final GA rate posted by the IESO that had been used for previous true ups. These differences will be recorded and trued up with the IESO during 2019, but has been reflected in the attached DVA. BPI notes the adjustments have not yet been entered into the G/L via journal entries, however the journal entries would be as follows:

TO CORRECT 2017 TRUE-UP			
20.000.181111.1588	RSVA - COST OF POWER - PRINCIPAL	666,597.20	
20.000.511110.4705	POWER PURCHASED		666,597.20
20.000.511110.4705	POWER PURCHASED	666,597.20	
20.000.211751.2220	DUE TO IESO		(666,597.20)
TO CORRECT 2018 TRUE-UP			
20.000.181111.1588	RSVA - COST OF POWER - PRINCIPAL	917,045.48	
20.000.511110.4705	POWER PURCHASED		(917,045.48)
20.000.511110.4705	POWER PURCHASED	917,045.48	
20.000.211751.2220	DUE TO IESO		(917,045.48)

The new process identified variances in the 1588 account for both the 2017 balance which was approved on an interim basis as well as the 2018 balance. Both years' adjustments resulted in amounts owing to the IESO, shown above resulting in a debit principle adjustment in account 1588. The 2017 adjustment is reflected in cell AV28 and 2018 is reflected in cell BF28 of the tab 3-continutity schedule.

A comparison of the initial monthly true ups and the true ups reflecting the new accounting guidance is shown below, outlining the quantification of the adjustments made:

Table 1.5.6-E: 1588 Changes as a Result of OEB Accounting Guidance

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2018 True-Up elements - OEB New Method													
Tier 1	$ 33,645.58	$ (36,546.74)	$ 65,526.87	$ (52,036.98)	$ 240,640.57	$ 37,667.39	$ 137,915.64	$ (28,816.81)	$ (52,015.54)	$ 50,159.43	$ (35,191.86)	$ (23,709.39)	$ 337,238.16
Tier 2	$ 1,272.96	$ (4,214.13)	$ 17,789.39	$ (15,872.61)	$ 128,095.32	$ 13,449.57	$ 55,131.36	$ (18,152.19)	$ (34,247.77)	$ 53,182.98	$ (6,956.69)	$ (4,320.58)	$ 185,157.59
TOU Off-peak	$ (162,087.40)	$ 97,537.71	$ (120,595.19)	$ (38,124.01)	$ 320,962.94	$ (427,886.44)	$ 131,606.46	$ (144,564.88)	$ 76,308.69	$ (92,763.94)	$ (38,465.44)	$ 144,446.27	$ (253,625.22)
TOU Mid-peak	$ (23,086.67)	$ 35,731.94	$ (40,027.35)	$ (5,879.52)	$ 123,076.34	$ (111,646.86)	$ 42,092.54	$ (26,688.79)	$ (5,712.12)	$ (8,689.16)	$ 16,268.24	$ 17,071.01	$ 12,509.60
TOU On-peak	$ (19,295.18)	$ 48,925.03	$ (44,897.44)	$ 3,462.48	$ 131,996.82	$ (106,497.33)	$ 51,605.35	$ (30,835.34)	$ 10,355.64	$ (2,607.27)	$ 26,656.29	$ 15,499.55	$ 84,368.60
	$ (169,550.70)	$ 141,433.81	$ (122,203.73)	$ (108,450.64)	$ 944,771.98	$ (594,913.68)	$ 418,351.35	$ (249,058.00)	$ (5,311.09)	$ (717.97)	$ (37,689.46)	$ 148,986.86	$ 365,648.73
2018 Original True-up recorded in 2018													
Tier 1	$ 33,504.44	$ (35,282.70)	$ 65,346.53	$ (52,293.40)	$ 240,424.26	$ 38,317.45	$ 133,467.02	$ (24,927.61)	$ (52,185.58)	$ 49,886.41	$ (15,943.07)	$ (39,818.24)	$ 340,495.52
Tier 2	$ 1,144.16	$ (3,287.82)	$ 17,650.28	$ (16,036.48)	$ 127,936.69	$ 13,956.04	$ 50,209.52	$ (14,151.19)	$ (34,410.06)	$ 52,986.93	$ 4,691.66	$ (15,067.19)	$ 185,622.55
TOU Off-peak	$ (319,008.34)	$ 35,866.68	$ (75,740.74)	$ (88,896.36)	$ 232,074.96	$ (513,587.49)	$ 43,295.56	$ (172,781.47)	$ 147,994.87	$ (176,765.08)	$ (14,528.60)	$ 189,420.81	$ (712,655.19)
TOU Mid-peak	$ (33,857.49)	$ (10,335.41)	$ (28,524.78)	$ (30,705.74)	$ 120,737.83	$ (146,245.18)	$ 16,957.63	$ (13,277.42)	$ (43,859.59)	$ (25,415.42)	$ 34,733.41	$ (6,063.53)	$ (165,855.71)
TOU On-peak	$ (36,160.23)	$ (13,639.07)	$ (31,284.03)	$ (20,705.14)	$ 121,760.20	$ (180,919.51)	$ 32,753.37	$ (15,797.69)	$ (47,554.46)	$ (42,956.47)	$ 43,513.01	$ (8,013.90)	$ (199,003.92)
	$ (354,377.45)	$ (26,678.32)	$ (52,552.74)	$ (208,637.12)	$ 842,933.94	$ (788,478.68)	$ 276,683.11	$ (240,935.38)	$ (30,014.82)	$ (142,263.64)	$ 52,466.41	$ 120,457.95	$ (551,396.76)
2018 Adjustment to be made 2019													
Tier 1	$ 141.14	$ (1,264.04)	$ 180.33	$ 256.43	$ 216.30	$ (650.07)	$ 4,448.62	$ (3,889.20)	$ 170.04	$ 273.01	$ (19,248.78)	$ 16,108.85	$ (3,257.36)
Tier 2	$ 128.80	$ (926.32)	$ 139.11	$ 163.87	$ 158.63	$ (506.47)	$ 4,921.84	$ (4,001.00)	$ 162.28	$ 196.05	$ (11,648.36)	$ 10,746.61	$ (464.96)
TOU Off-peak	$ 156,920.94	$ 61,671.02	$ (44,854.46)	$ 50,772.35	$ 88,887.98	$ 85,701.05	$ 88,310.90	$ 28,216.59	$ (71,686.17)	$ 84,001.14	$ (23,936.84)	$ (44,974.54)	$ 459,029.97
TOU Mid-peak	$ 10,770.82	$ 46,067.36	$ (11,502.56)	$ 24,826.22	$ 2,338.51	$ 34,598.32	$ 25,134.91	$ (13,411.36)	$ 38,147.48	$ 16,726.26	$ (18,465.17)	$ 23,134.54	$ 178,365.31
TOU On-peak	$ 16,865.05	$ 62,564.10	$ (13,613.41)	$ 24,167.62	$ 10,236.61	$ 74,422.17	$ 18,851.97	$ (15,037.64)	$ 57,910.10	$ 40,349.20	$ (16,856.72)	$ 23,513.46	$ 283,372.52
	$ 184,826.75	$ 168,112.13	$ (69,650.98)	$ 100,186.48	$ 101,838.04	$ 193,565.00	$ 141,668.24	$ (8,122.62)	$ 24,703.73	$ 141,545.67	$ (90,155.87)	$ 28,528.91	$ 917,045.48

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2017 True-Up elements - OEB New Method													
Tier 1	$ 22,040.68	$ (15,618.99)	$ (22,621.67)	$ (31,973.37)	$ 108,470.67	$ 69,058.26	$ 55,468.99	$ 57,202.64	$ (21,335.94)	$ 40,381.72	$ (34,704.78)	$ 45,029.01	$ 271,397.23
Tier 2	$ (17,168.88)	$ 14,487.34	$ (48,389.83)	$ 654.03	$ 22,941.12	$ 31,615.81	$ 19,098.62	$ 27,224.54	$ (4,172.79)	$ 10,232.92	$ (11,272.76)	$ 8,742.69	$ 53,992.81
TOU Off-peak	$ 34,192.45	$ (45,635.52)	$ (57,828.28)	$ (48,093.25)	$ 73,102.05	$ 60,431.98	$ (101,972.13)	$ 20,332.75	$ 189,437.69	$ (161,746.12)	$ (91,935.75)	$ 205,254.51	$ 75,540.36
TOU Mid-peak	$ 26,388.02	$ (24,611.50)	$ (7,354.53)	$ (19,271.95)	$ 18,933.69	$ (404.14)	$ (25,412.71)	$ 27,778.38	$ 49,360.80	$ (42,261.27)	$ (8,013.28)	$ 24,417.60	$ 19,549.12
TOU On-peak	$ 46,215.60	$ (41,596.13)	$ 1,573.49	$ (9,018.29)	$ 29,859.23	$ 4,632.73	$ (18,884.15)	$ 23,784.10	$ 61,404.04	$ (26,466.30)	$ 3,393.82	$ 24,452.52	$ 99,350.67
	$ 111,667.88	$ (112,974.80)	$ (134,620.82)	$ (107,702.84)	$ 253,306.77	$ 165,334.63	$ (71,701.38)	$ 156,322.42	$ 274,693.81	$ (179,859.05)	$ (142,532.75)	$ 307,896.33	$ 519,830.18
2017 Original True-up recorded													
Tier 1	$ 21,686.32	$ (15,890.78)	$ (22,616.05)	$ (32,477.82)	$ 107,974.57	$ 82,941.03	$ 39,632.62	$ 56,506.14	$ (21,851.73)	$ 39,748.37	$ (34,597.72)	$ 44,910.18	$ 265,965.13
Tier 2	$ (17,452.71)	$ 14,302.05	$ (48,385.89)	$ 428.32	$ 22,616.56	$ 39,588.71	$ 9,623.25	$ 26,805.00	$ (4,465.33)	$ 9,834.20	$ (11,208.96)	$ 8,643.08	$ 50,328.29
TOU Off-peak	$ (99,468.84)	$ 76,597.16	$ (146,339.96)	$ 69,420.44	$ 64,305.48	$ 256,014.87	$ (298,946.90)	$ (50,415.79)	$ 184,757.92	$ (235,628.15)	$ (210,301.82)	$ 340,834.86	$ (49,170.74)
TOU Mid-peak	$ (20,325.15)	$ (2,598.60)	$ (31,237.78)	$ (44,890.60)	$ (6,625.46)	$ 23,249.36	$ (91,375.32)	$ 42,940.68	$ 30,578.89	$ (85,943.45)	$ (41,878.80)	$ 26,571.21	$ (201,535.04)
TOU On-peak	$ (23,896.22)	$ 8,117.31	$ (32,242.57)	$ (47,575.66)	$ (10,969.61)	$ 28,296.90	$ (108,755.04)	$ 55,450.18	$ 45,807.72	$ (122,603.07)	$ (32,507.80)	$ 28,523.22	$ (212,354.65)
	$ (139,456.60)	$ 80,527.14	$ (280,822.26)	$ (55,095.32)	$ 177,301.53	$ 430,090.86	$ (449,821.38)	$ 131,286.21	$ 234,827.46	$ (394,592.10)	$ (330,495.10)	$ 449,482.54	$ (146,767.01)
2017 Adjustment to be made 2019													
Tier 1	$ 354.36	$ 271.79	$ (5.62)	$ 504.46	$ 496.11	$ (13,882.77)	$ 15,836.36	$ 696.50	$ 515.79	$ 633.35	$ (107.06)	$ 118.82	$ 5,432.09
Tier 2	$ 283.83	$ 185.29	$ (3.94)	$ 225.70	$ 324.56	$ (7,972.90)	$ 9,475.37	$ 419.54	$ 292.54	$ 398.71	$ (63.80)	$ 99.61	$ 3,664.52
TOU Off-peak	$ 133,661.29	$ (122,232.68)	$ 88,511.67	$ (117,513.70)	$ 8,796.57	$ (195,582.90)	$ 196,974.77	$ 70,748.54	$ 4,679.78	$ 73,882.03	$ 118,366.07	$ (135,580.35)	$ 124,711.10
TOU Mid-peak	$ 46,713.17	$ (22,012.89)	$ 23,883.26	$ 25,618.65	$ 25,559.15	$ (23,653.50)	$ 65,962.61	$ (15,162.29)	$ 18,781.92	$ 43,682.18	$ 33,865.52	$ (2,153.61)	$ 221,084.17
TOU On-peak	$ 70,111.82	$ (49,713.44)	$ 33,816.06	$ 38,557.37	$ 40,828.84	$ (23,664.16)	$ 89,870.89	$ (31,666.07)	$ 15,596.32	$ 96,136.77	$ 35,901.62	$ (4,070.69)	$ 311,705.32
	$ 251,124.48	$ (193,501.94)	$ 146,201.43	$ (52,607.52)	$ 76,005.23	$ (264,756.23)	$ 378,120.00	$ 25,036.21	$ 39,866.35	$ 214,733.04	$ 187,962.35	$ (141,586.22)	$ 666,597.20
Total 2017 & 2018 Adjustments													
Tier 1	$ 495.50	$ (992.25)	$ 174.71	$ 760.88	$ 712.41	$ (14,532.83)	$ 20,284.98	$ (3,192.70)	$ 685.83	$ 906.36	$ (19,355.85)	$ 16,227.68	$ 2,174.73
Tier 2	$ 412.63	$ (741.03)	$ 135.17	$ 389.57	$ 483.19	$ (8,479.37)	$ 14,397.20	$ (3,581.46)	$ 454.82	$ 594.77	$ (11,712.16)	$ 10,846.22	$ 3,199.56
TOU Off-peak	$ 290,582.24	$ (60,561.66)	$ 43,657.22	$ (66,741.35)	$ 97,684.55	$ (109,881.84)	$ 285,285.67	$ 98,965.13	$ (67,006.40)	$ 157,883.17	$ 94,429.23	$ (180,554.89)	$ 583,741.07
TOU Mid-peak	$ 57,483.99	$ 24,054.47	$ 12,380.70	$ 50,444.87	$ 27,897.66	$ 10,944.82	$ 91,097.52	$ (28,573.66)	$ 56,929.39	$ 60,408.44	$ 15,400.35	$ 20,980.93	$ 399,449.48
TOU On-peak	$ 86,976.87	$ 12,850.66	$ 20,202.65	$ 62,724.99	$ 51,065.46	$ 50,758.01	$ 108,722.86	$ (46,703.72)	$ 73,506.42	$ 136,485.97	$ 19,044.90	$ 19,442.76	$ 595,077.84
	$ 435,951.23	$ (25,389.81)	$ 76,550.45	$ 47,578.96	$ 177,843.27	$ (71,191.22)	$ 519,788.24	$ 16,913.59	$ 64,570.07	$ 356,278.71	$ 97,806.48	$ (113,057.30)	$ 1,583,642.68

The November and December power purchase true-up amounts were recorded in BPI's 2019 GL and relate to the 2018 balances, resulting in a variance from the 2018 RRR data. The amount combined for November and December offsets the amount which is identified as a variance in 1589 Global Adjustment below.

Account 1589 RSVA – Global Adjustment, Variance: $27,740

As identified in the GA Analysis workform as part of this application, BPI identified this amount as a reconciling item relating to items recorded in the GL in 2019 that relate to 2018. This was the true-up for CT 148 with the IESO for both November $75.11 and December ($27,816.46) netting to the principal adjustment shown in cell BF29 in tab 3 continuity schedule of the 2020 rate generator.

Please note that the GA Activity in 2018 of $(1,421,538) has been adjusted from the G/L to exclude prior period adjustments completed in 2018 of $(371,877) related to adjustments made in the 2019 IRM Application.

Account 1568- LRAMVA, Variance: $368,002

As part of this Application, BPI is not proposing disposition of amounts in its LRAMVA account, which are related to CDM Program results in 2018 (when adjusted for the disposition during 2019). The CDM savings for the 2018 LRAMVA includes 2017 persistence into 2018 and 2018 new program results.

As a result of not applying for LRAMVA Disposition BPI followed the instructions in cell C43 on tab 3. Continuity Schedule of the rate generator model and did not input any amounts related to account 1568 in the schedule. This resulted in a variance of $368,002, the entire amount of the 2018 RRR balance.

Adjustments to Deferral and Variance Accounts

The filing requirements, section 3.2.5, state that the OEB expects that no adjustments will be made to deferral and variance account balances which have been previously approved by the OEB on a final basis.

As discussed above in section 1.5.6, BPI has made principal adjustments to accounts 1588-RSVA Power, totaling $666,597 in 2017 principle and $944,786 in 2018 and 1589 RSVA Global Adjustment totaling $(27,740), however 2017 balances were approved on an interim (not final) basis, and 2018 balances have not yet been reviewed.

These adjustments include the following:

•amounts related to the November and December 2018 IESO True-ups which were recorded in the GL in 2019; and

•Adjustments to 1588 related to 2017 and 2018 balances discovered as a result of the implementation of the OEB's new accounting guidance.

In BPI's 2019 IRM Filing (EB-2018-0020) BPI made principle adjustments in 2018 relating to the years 2016 and 2017, the reversal of these adjustments were not recorded as principle adjustments in the continuity schedule as part of this 2020 IRM application, rather the prior year adjustments were removed from the 2018 regular activity transactions reported in RRR. As such, the transactions recorded in column BD in tab 3 represent the true 2018 transactions.

Wholesale Market Participants (WMPs)

WMPs are customers that arrange to be billed directly by the IESO for certain charges. BPI has two such customers in its General Service 50 to 4,999 kW customer class, and consistent with the expectations set out in Section 3.2.5.1 of the Filing Requirements, BPI only bills certain rates to these customers—primarily Distribution and Transmission rates.

As a result of not meeting the threshold test for disposition, BPI has not proposed to dispose of the Group 1 DVA balances, and therefore no special adjustments for rate riders to WMPs are necessary. BPI proposes that the ICM rate riders for General Service 50 to 4,999 kW should be applicable to WMPs as well, as the ICM claim is related to distribution related expenses, which are billed by BPI to its WMPs.

Commodity Accounts 1588 and 1589

BPI is in the process of preparing the Global Adjustment Analysis Workform with respect to its 2018 balance and intends to file this document and the associated questions in Appendix A of the OEB's instructions at a later date. BPI notes that it is not proposing the disposition of or final adjustments to Accounts 1588 and 1589.

BPI does not use the actual Global Adjustment price to bill any customers, and therefore has made no proposal to exclude any non-RPP customers from being charged the Global Adjustment Rate Rider for this reason (with the exception of WMP customers and Class A and former Class A customers).

Additionally, Section 3.2.5.2 requires BPI to provide a description of its settlement process with the IESO.

BPI has itemized the OEB's directions regarding the information requirements, and provides the following responses below:

- **Specify the GA rate it uses when billing its customers (1st estimate, 2nd estimate or actual) for each rate class.**

Response:

BPI uses the first estimate to bill its customers. This treatment is applicable for all customer classes.

- **Itemize its process for providing consumption estimates to the IESO**.

Response:

BPI settles monthly with the IESO for the difference between spot and RPP pricing, for RPP customers with either (1) Time-Of-Use (TOU) meters or (2) Conventional meters. The settlement is completed within four business days of month end.

(1) Time-Of-Use meters: At month end, read dates are obtained for that calendar month. The metered data is separated into on-peak, mid-peak, and off-peak data. BPI compares the smart meter data with its Customer Information System (CIS) to determine which customers are billed on TOU rates. Any retailer customer consumption is then excluded, to ensure BPI is only settling for those customers billed on TOU, with the IESO.

(2) Conventional meters: effective April 23, 2019, BPI implemented a new CIS. The new CIS required BPI to update the processes for estimating consumption for conventional meters. BPI obtains data from the new CIS to list all customers that are billed using Tier 1 and Tier 2 rates. BPI reviewed historical billings from the previous CIS to determine average consumption for each of these customers. The estimated consumption is split between Tier 1 and Tier 2 based on the number of customers in each group and if they traditionally exceed the Tier 1 consumption limit. The total RPP consumption is then calculated by adding the consumption of customers on TOU rates to the consumption of customers on conventional meters, as explained above. The RPP portion of the Class B Global Adjustment line from the IESO bill is then allocated to account 4705-Cost of Power, based on the estimated RPP consumption calculated, in comparison to total kWh purchased. The remaining portion of the Class B Global Adjustment line (relating to non-RPP customers) from the IESO bill is allocated to 4707-Global Adjustment.

BPI notes that its process for providing consumption estimates to the IESO contains some inherent assumptions, in part due to data timing and data limitations. With the implementation of the new CIS in April 2019, the timing of BPI's true-up has incurred delays as new reporting is developed to assist in the calculation of consumption. BPI has committed to have all true-up reporting completed in conjunction with the August 31, 2019 deadline to implement the new Accounting Guidance related to 1588/1589.

- **Describe the true-up process to reconcile estimates of RPP and non-RPP consumption once actuals are known. The description should detail the distributor's method for estimating RPP and non-RPP consumption**

Response:

BPI reconciles the estimate of TOU, RPP and non-RPP consumption to actuals for each month. Consumption for RPP customers with conventional and TOU meters is trued-up using the actual commodity billings. Billings including the two months following month end are reviewed and prorated to the appropriate month based on read date. As indicated above, the implementation of the new CIS has impacted the timing of BPI's true-ups. BPI continues to develop and validate the necessary reporting to complete these true-ups and will resume monthly true-ups by August 31, 2019.

During the implementation of the new Accounting Guidance for 1588 and 1589 commodity accounts, BPI discovered a variance between the TOU true ups that had been recorded for 2017 and 2018. The variance resulted in additional amounts owing to the IESO of $1,583,643 (2017 - $666,597.20; 2018 - $917,045.48). These adjustments also affect the balance of 1588 resulting in a necessary recovery from customers as reflected in the DVA continuity schedule. The original true up calculation did not factor the difference between final pricing and RPP pricing on the consumption difference between estimated and actual consumption. Smaller variances resulted from the use of a calculated Global Adjustment (GA) rate per the OEB model and the final GA rate posted by the IESO that had been used for previous true ups. These differences will be recorded and trued up with the IESO during 2019.

The implementation of the new Accounting Guidance confirmed the allocation of consumption between RPP and non-RPP customers for 2017 and 2018. There was no adjustment required related to the split between 1588 and 1589 for CT 148 from the IESO invoice.

BPI has reviewed the balances in 2016 and the issue related to the true up of the final differential between estimated and final consumption at the final pricing was not present in that year. BPI's 2016 process in 2016 differed from the process in the Accounting guidance as a result of BPI's use of the posted final GA rate rather than the billed Global Adjustment divided by power purchases as the final rate. BPI believes this was a reasonable source for GA pricing, and that any differences were non material, and as a result BPI has not made any corresponding adjustments to 2016 balances.

- **[The description should detail the] treatment of embedded generation or any embedded distribution customers.**

Response:

Together with IESO purchases, embedded generation and power purchases from embedded distributors are taken into consideration when determining the total power purchases for the month.

- **Distributors are reminded that they are expected to use accrual accounting.**

Response:

BPI confirms that it uses accrual accounting in its Global Adjustment settlement processes.

Global Adjustment Rate Riders

Most customers who are not on RPP pricing (meaning customers enrolled with a retailer and customers who pay the Hourly Ontario Electricity Price) pay the Global Adjustment based on their monthly kWh consumption. These are non-RPP, Class B customers. Other customers who qualify for and participate in the Industrial Conservation Initiative (ICI) are referred to as Class A customers. BPI settles Class A Global Adjustment costs on a different basis, which does not result in any variance related to Global Adjustment being accumulated.

BPI had twenty-six customers who were Class A customers during the period eligible for disposition (January 1, 2018 to December 31, 2018). Of these twenty-six , sixteen customers were Class A during this entire period (Customers Class A Consumption Data is consolidated in the rate classes with Class A customers section in tab 6) and ten customers which were Class A for only part of the period (Customers 1 through 10 in Tab 6 Class A Consumption Data).

No disposition of the Group 1 balances is being proposed, including the Global Adjustment. As a result, BPI has not calculated Global Adjustment rate riders or adjustments for Class A transition customers.

Capacity Based Recovery (CBR)

Similar to the Global Adjustment, CBR is charged to Class B customers on the basis of their consumption and BPI settles CBR on a different basis with Class A customers. The variances associated with Class A and Class B customers for CBR are tracked separately in sub accounts 1580-RSVA Wholesale Market Service Charge- CBR Class A and 1580-RSVA Wholesale Market Service Charge- CBR Class B. BPI’s 1580-RSVA Wholesale Market Service Charge- CBR Class A has a balance of $0, consistent with the expectations in the OEB’s CBR Accounting Guidance.

As no disposition of Group 1 balances is being proposed, CBR rate riders or adjustments for transition Class A customers are not being proposed.

Account 1595

Consistent with the Filing Requirements, Chapter 3, Appendix A, BPI is only eligible to dispose of the balance in Account 1595-2017. This account represents the remaining variance associated with the regulatory balances disposed of during 2017. As of December 31, 2017 these rate riders have expired, and the associated ending balance in account 1595-2017 was audited as part of the 2017 year-end audit.

BPI has completed the reconciliation required for account 1595-2017, and the variance for total group 1 and group 2 balances excluding account 1589 is -1.7%, and the variance for account 1589 – Global Adjustment is 4.8%, neither meet the threshold (variance of +/-10%) requiring further explanation. The reconciliation calculation is laid out below:

Table 1.5.6-F: Account 1595-2016 Reconciliation

Components of the 1595 Account Balances:	Principal Balance Approved for Disposition	Carrying Charges Balance Approved for Disposition	Total Balances Approved for Disposition	Rate Rider Amounts Collected/(Returned)	Residual Balances Pertaining to Principal and Carrying Charges Approved for Disposition	Carrying Charges Recorded on Net Principal Account Balances	Total Residual Balances	Collections/Returns Variance (%)
Total Group 1 and Group 2 Balances excluding Account 1589 - Global Adjustment	-$2,778,621	$25,564	-$2,753,057	-$2,798,935	$45,878	-$16,111	**$29,767**	**-1.7%**
Account 1589 - Global Adjustment	$1,613,940	$24,341	$1,638,281	$1,559,629	$78,652	$7,358	**$86,011**	**4.8%**
Total Group 1 and Group 2 Balances	-$1,164,681	$49,905	-$1,114,776	-$1,239,306	$124,530	-$8,752	**$115,778**	**-11.2%**
						Total residual balance per continuity schedule:	$115,779	
						Difference (any variance should be explained):	**$1**	

BPI has also included this form as IRM Attachment H: 1595 Analysis Work Form.

1.5.7 Lost Revenue Adjustment Mechanism Variance Account (LRAMVA)

BPI is not proposing the disposition of the balance in its LRAMVA Account 1568. The balance eligible for disposition in this account relates to the impacts of 2018 programs in 2018. In its 2019 Application, BPI disposed of $339,767 of the balance to the end of 2018, and therefore a non-material amount of roughly $27k remains in the account. This amount has not yet been adjusted for the updated LRAMVA methodology set out in the OEB's addendum to the Filing Requirements released July 15, 2019. BPI intends to file for the disposition of the LRAMVA balance in a future IRM or COS rate application and will calculate adjusted LRAMVA consistent with the July 15th methodology .

1.5.8 Tax Changes

As discussed in section 3.2.7 of the Filing Guidelines, the OEB requires a 50-50 sharing of the impacts of legislated tax changes from the tax rates embedded in an LDC's OEB approved rates, based on the known tax rates at the time of the application. BPI's last such application is its 2017 Cost of Service Rate Application. BPI has consulted KPMG's *Substantively Enacted Income Tax Rates for Income Earned by a General Corporation for 2019 and Beyond—As at June 30, 2019,* (included as IRM Attachment G) and has determined that there is no applicable tax change. As a result, and consistent with the Filing Guidelines, BPI has not completed Tab 9 of the 2020 IRM Rate Generator, and is not proposing and Tax Sharing Rate Riders. Should an update to corporate taxes be issued prior to the issuance of a Decision and Rate Order in this Application, BPI will update its application to take these changes into consideration.

As per the OEB letter released July 25, 2019 regarding Accounting Direction Regarding Bill C-97 and Other Changes in Regulatory or Legislated Tax Rules for Capital Cost Allowance BPI has not captured the impact in tab 8 STS-Tax Change. BPI confirmed with OEB staff that the tax change amounts as a result of the accelerated CCA are to be recorded in account 1592 and not to be captured in the Shared Tax Savings tab at this time. BPI will book the 2018 accelerated CCA adjustment to the 1592 variance account and intends to complete the necessary steps to ensure that 100% of the variance is included in the variance account.

1.5.9 Z- Factor Claims

The OEB allows Price Cap IR applicants to request to recover costs associated with material, unforeseen extraordinary events- typically those associated with extreme weather events. BPI has incurred no such events and is not applying for the recovery of any Z-Factor amounts.

1.5.10 Advanced Capital Module

The Advanced Capital Module mechanism is discussed in section 3.3.1 of the Filing Guidelines and in the OEB's *Report of the Board- New Policy Options for the Funding of Capital Investments: The Advanced Capital Module* (EB-2014-0219, the "ACM Report"). A distributor under Price Cap IR rate setting may make an ACM request as part of a cost of service, which if approved, would allow the distributor to recover costs related to certain capital programs in a subsequent Price Cap IR application. BPI did not include any ACM requests in its 2017 Cost of Service Application, and therefore this section is not applicable.

1.5.11 Incremental Capital Module (ICM)

Distributors on Price Cap IR rates setting are eligible to make an ICM funding request during a Price Cap IR Application for capital investment needs which are material and incremental to the levels of funding currently assumed in the distributor's base rates, and beyond an OEB-defined materiality threshold.

In this Application, BPI is proposing incremental capital funding for its Facility Relocation project to a consolidated facility at 150 Savannah Oaks Drive. The new building will be in use in early 2020, BPI is therefore requesting funding through incremental capital rate riders effective January 1st, 2020. BPI's ICM supporting evidence and calculations (as well as related appendixes) is included as IRM Attachment A.

BPI's existing leases will not be renewed at the end of the agreement and BPI is required to relocate as a result. Following a lengthy search which considered various relocation options against a set of criteria, BPI purchased the selected 150 Savannah Oaks for its consolidated operations and administrative building. The new location includes an existing building which requires some refurbishments, as well as some new construction.

In order to make efficient use of the facility and to limit impacts to ratepayers, BPI has made arrangements to share this facility with its affiliates and its neighbouring LDC, Energy+. The sharing arrangement with Energy+ will enable additional efficiencies and improvements to service as the two utilities will share certain utility functions at this facility. To further reduce costs to ratepayers, BPI has also arranged to lease the majority of the first floor of its office building to a "third tenant" and to sell 13.9 Acres of severable land.

BPI has used the OEB's model for ICM and ACM to calculate the incremental annual revenue requirement (above the OEB-defined ICM materiality threshold) associated with the facility, as well as monthly rate riders for each customer class. BPI is proposing these rate riders should be in place until effective date of the rates from its next cost-based rate application, and therefore BPI has not proposed a specific sunset date for the rate riders. This is currently expected to be a Cost of Service Application for rates effective January 1, 2022. The proposed monthly ICM rate riders are summarized below. BPI has included these rate riders in its Proposed Tariff Sheet and the associated Bill Impacts. The table below confirms that the total bill impacts with the ICM rate riders and all other proposed rate adjustments in this Application do not exceed the 10% threshold which would require consideration of bill mitigation measures.

Table 1.5.11: ICM Rate Riders Summary

Rate Class	Allocated Revenue Requirement	Proposed Rate Rider-Monthly Building Bill Impact	Billing Unit	Total Bill Impact (Including IRM Adjustments)
Residential	$ 768,122.60	$ 1.75	per month	3.7%
General Service Less Than 50 kW	$ 134,669.58	$ 3.98	per month	3.3%
General Service 50 to 4,999 kW	$ 411,661.19	$ 70.44	per month	4.5%
Embedded Distributor	$ 14,584.27	$ 1,215.36	per month	0.0%
Sentinel Lighting	$ 2,698.19	$ 0.45	per month	4.9%
Street Lighting	$ 17,531.05	$ 0.25	per month	5.2%
Unmetered Scattered Load	$ 5,795.44	$ 1.18	per month	4.2%
Total	$1,355,062.32			

Please refer to IRM Attachment A for a fulsome discussion of the facility relocation project, including evidence related to the ICM requirements for need, prudence and materiality.

1.5.12 Treatment of Costs for Eligible Investments

Distributors who have not yet filed a Distribution System Plan under Chapter 5 of the Filing Requirements can record renewable energy generation costs and smart grid development costs in the deferral accounts established for this purpose. BPI filed its first Distribution System Plan under Chapter 5 of the Filing Requirements in its 2017 COS, EB-2016-0058. Therefore, BPI understands that section 3.3.3 ("Treatment of Costs for 'eligible investments'") does not apply in this Application.

1.5.13 Conservation and Demand Management ("CDM") Costs for Distributors

CDM activity can be funded either through IESO Contracted Province Wide CDM Programs, or through an OEB-approved CDM program. BPI does not have any OEB-approved programs.

1.5.14 Return on Equity ("ROE") Dead Band – Off Ramps

Distributors report annually on their financial position through their RRR reporting in April of each subsequent year. One of the key outcomes of this financial reporting is the actual level of ROE achieved by the Distributor. A Distributor's OEB-approved rates include a deemed ROE component set at a specific level. If a distributor's real ROE in any given year is outside of a dead band of +/- 300 basis points, from the deemed ROE level, the OEB may require a regulatory review.

As discussed in section 3.3.5 of the Filing Requirements, a distributor whose earnings are in excess of the dead band is expected to refrain from seeking a rate adjustment.

BPI's last RRR annual filing was for the 2018 fiscal year. The applicable deemed ROE for 2018 was established in BPI's 2017 COS Rate Application.

BPI's 2018 achieved ROE was 7.90%, which does not exceed the off-ramp rate of 5.78% (8.78% deemed - 3.00% dead band). Therefore the ROE dead band Price Cap IR off – ramp does not apply.

1.5.15 Specific Exclusions from Price Cap IR or Annual IR Index Applications

Consistent with the Filing Requirements Section 3.4, BPI is not requesting to seek relief in this Application on any of the following items:

- Rate Harmonization;
- Disposition of the balance of Account 1555-Smart Meter Capital Costs, Dub-Account Stranded Meter Net Book Value;
- Changed to revenue-to-cost ratios;
- Loss Factor Changes;
- Establishing or changing Specific Service Charges;
- Loss Carry Forward Adjustments to PILS/taxes;
- Disposition of Group 2 Deferral and Variance Accounts;
- Loss of Customer Load.

1.6 Request for New Variance Account

BPI has consulted the Filing Requirements, Section 2.9.4 in relation to the establishment of a new Variance Account and believes it has met the requirements of demonstrating Causation, Materiality and Prudence with respect to its proposal for a new Variance Account related to Lost Revenues from the discontinuation of the $30 Collection of Account charge. BPI's rationale with for each of the evidentiary requirements is set out below, as well as a draft accounting order and sample journal entries. BPI is proposing the new Variance account will be a sub-account to 1508 – Other Regulatory Assets. The proposed sub-account is "Lost Revenues-Collection of Account Charge"

Causation

BPI is licensed by the OEB to distribute electricity in the City of Brantford (ED-2003-0060). As a condition of license BPI must comply with OEB Codes, including any Rate Order issued by the OEB.

BPI last rebased its distribution rates through a Cost of Service ("CoS") application that was filed on May 4, 2016 (EB-2016-0058) and that the OEB approved by Order dated November 24, 2016. BPI's "Base Revenue Requirement" was quantified assuming that the company would continue to bill the "Collection of account charge-no disconnection" to customers where a disconnection notice is issued in order to collect an overdue account payment. These charges were included in the Revenue Offsets in BPI's 2017 CoS application.

However, on November 2, 2017, after the Decision in its CoS, the OEB made amendments to the licenses of all electrical distributors in its Decision and Order (EB-2017-0318) that set out a Disconnection Ban Period from November 15th to April 30th of the following year and on a going forward basis. The updated license conditions required that any Collection of Account charges that could otherwise be charged to residential customers shall be waived during the Disconnection Ban Period. Furthermore, on December 18, 2018 the OEB issued a Notice of Proposal to Amend Codes and a Rule as part of the OEB's Review of the Customer Service Rules.

In that Notice, the OEB proposed to eliminate the OEB-approved Collection of Account charge and acknowledged that the elimination of charges related to non-payment would impact many distributors. The OEB stated that it would accept applications from any distributor for a deferral account with evidence demonstrating the account met the eligibility tests set out in the OEB's Chapter 2 Filing Requirements for Electricity Distribution Rate Applications. Finally, on March 14, 2019 the OEB issued a Notice of Amendments to Codes and a Rule and a Rate Order related to the non-payment of account service charges and confirmed that they did not find it prudent to establish a generic deferral account for lost revenues from eliminated charges and the effective date of the change would be July 1, 2019.

As a result of the Rate Order BPI will incur lost revenue by eliminating the Collection of Account charge.

BPI's costs are expected to remain relatively unchanged from those approved in the 2017 CoS application as collections activities will continue to be required. BPI notes that it has recently switched to mailing disconnection notices rather than using hand delivery previously done by a third party. The cost savings per notice are relatively limited, about $1.05 per notice. Additionally, the ban on winter disconnections has not resulted in a proportional decrease in the collection activity required, as customers who normally would have been eligible for disconnection often accrue further arrears during the winter period. Permitted collection activities which aren't related to disconnection, including sending account overdue notices and setting up arrears management plans, still continue during the winter disconnection ban.

Prudence

The annual amount of lost revenue is $440,889 based on the test year (2017) value approved in BPI's 2017 CoS application.

The Settlement Agreement supporting OEB's Decision and Order, issued November 24, 2016 states

"The Parties accept the evidence of BPI that all elements of thee Revenue Requirement have been correctly determined in accordance with OEB policies and practices."

In its Decision, the OEB stated that:

"The OEB finds that the Settlement Proposal produces outcomes that are compatible with the applicable performance objectives of the Renewed Regulatory Framework (RRFE), and the resulting rates are just and reasonable. The OEB approves the Settlement Proposal."

The Settlement includes an overall service revenue requirement of $18,413,955, representing the total approved costs recoverable on an annual basis. This is adjusted downwards by a Revenue Offsets of $1,315,000 to arrive at a base revenue requirement of $17,098,955 to be recovered through distribution rates. Included in the Revenues offsets amount is a provision for expected collection of account charges which was developed prior to the establishment of the winter disconnection ban or the removal of the Collection of Account charge. Therefore, the Revenue Offsets agreed to by the parties and approved by the Board in BPI's CoS Decision were based on the assumption that BPI would be eligible to continue charging the Collection of Account charge. The total allotment included in Revenue Offsets for Collection of Account charges was $440,889.

Table 1.6-A below shows the impact of Collection of Account charges on the Base Revenue Requirement in BPI's 2017 CoS Decision.

1.6-A: Collection of Account Impact to Base Revenue Requirement

Revenue Requirement	CoS EB-2016-0058 (Settlement)	Base Revenue Requirement With no Collection of Account Revenue	Variance
Service Revenue Requirement	18,413,955	18,413,955	-
Revenue Offsets	(1,315,000)	(874,111)	(440,889)
Base Revenue Requirement	**17,098,955**	**17,539,844**	**(440,889)**

BPI's distribution rates are based on the Base Revenue Requirement of $17,098,955. Had the Collection of Account charges not been included in Revenue Offsets, the Service Revenue Requirement would have remained the same, and revenue offsets would have been reduced by $440,889, resulting in a Base Revenue Requirement to be collected through distribution rates of $17,539,844

Table 1.6-B shows the breakdown of BPI's Revenue Offsets. Please note, BPI has internally and in past rate applications referred to the $30 Collection of Account charge as "Field Collection Charge".

Table 1.6-B: Revenue Offsets in 2017 COS Decision

Revenue Offsets	CoS EB-2016-0058 (Settlement)
ARREARS CERTIFICATE REVENUE	(135)
CREDIT CHECK FEE	(3,655)
RETURNED CHEQUE CHARGE	(6,009)
NEW A/C SET UP FEE	(163,426)
FIELD COLLECTION CHARGE	*(440,889)*
RECONNECTION CHARGE	(16,304)
ELECTRIC RECONNECT AFTER HOURS	(12,319)
RECONNECT AT POLE	
TEMP HYDRO SERVICE CHARGE	(3,183)
TEMP U/G SERVICE CHARGE	
ENERGY SALES	(5,983)
OTHER	-
Specific Service Charges - Sub-total	***(651,903)***
Late Payment Charges	(235,599)
Other Operating Revenues	(264,212)
Other Income or Deductions	(163,286)
Total Revenue Offsets	**(1,315,000)**

Please see IRM Attachment F, which includes Ch.2 Appendix 2-H: Other Operating Revenues the Chapter 2 Appendix document supporting BPI's 2017 Decision.

BPI notes that there was a presentation discrepancy between the "Specific Service Charges" (which includes Collection of Account charges) and the "Other Operating Revenues" in Table 13 of BPI's Settlement Agreement Decision in its 2017 CoS application. The amount for Other Operating Revenues was reported in the row for Specific Service Charges and vice-versa. A review of the application and supporting evidence to the Settlement, for example tabs 3 and 5 of the supporting RRRWF included with the Decision, can confirm this was an inadvertent mis-mapping.

Materiality

The magnitude of the anticipated lost revenue, $440,889, exceeds BPI's materiality threshold of $92,070, as calculated below based on the 2017 approved Service Revenue Requirement.

Table 1.6-C: Calculation of Materiality Threshold

Materiality Threshold		
Service Revenue Requirement	$	**18,413,955**
Materiality %		**0.50%**
Materiality Threshold	$	**92,070**

BPI's Board approved ROE from its 2017 CoS application was 8.78%. BPI's actual ROE for 2017 and 2018 were 11.38% and 7.9590% respectively, falling within the deadband of 300 basis points. The elimination of the Collection of Account charge, based on the approved amount of $440,889 would have an impact of 146 basis points. This represents approximately half of the deadband allowance.

For the reasons stated above, BPI seeks Board approval to establish the requested deferral account to record the lost revenue associated with complying with the Rate Order which removed the Collection of Account charge.

A draft Accounting Order with draft Journal Entries is included below.

BPI is proposing to record the lost revenues in account 1508 – Other Regulatory Assets – Sub-account – Lost Revenues- Collection of Account Charge. Disposition of the balances recorded in the proposed deferral account will occur at BPI's next rebasing, currently expected for 2022 rates. The manner of disposition would be consistent with the disposition of BPI's other Group 2 DVA accounts, that is, based on kWh and across all customer classes.

No customer will be impacted by the granting of this Application until the proposed accounts are disposed of.

BPI proposes that the OEB proceed pursuant to 21(iv) b . of the Act. Alternatively, BPI requests that the Board proceed by way of a written hearing.

Draft Accounting Order and Proposed Journal Entries

Brantford Power shall establish USoA Account 1508 Sub-account Collection of Account Charges, effective July 1, 2019 to record the lost revenue resulting from this Rate Order. Charges to this account will be based on the annual expected revenue of $440,889 from BPI's 2017 Decision and Order, less any revenues from the Collection of Account charges prior to the OEB's removal of this Charge (applicable for 2019 only). This account is proposed to be eligible for Carrying Charges at the Board prescribed rate.

Sample accounting entries are provided below:

A. To record on a monthly basis the lost revenues for Collection of Account Charges

DR	Account 1508 Sub-account – Lost Revenue From Collection of Account Charges	xxx
CR	Account 4235 - Miscellaneous Service Revenues	xxx

Records the lost revenues related to collection of account charges.

B. To record on a monthly basis the Carrying Charges associated with Account 1508 Sub-account – Collection of Account Charges

DR	Account 1508 Sub-account – Lost Revenue From Collection of Account Charges: Carrying Charges	xxx
CR	Account 4405 Other Interest Income	xxx

To record the Carrying Charges on the monthly opening balance recorded in Account 1508 Sub-account – Lost Revenue From Collection of Account Charges at the applicable OEB-approved prescribed accounting interest rate.

All records shall be maintained at an appropriate level to permit Board review and verification of amounts recorded therein.

IRM Attachment A:

ICM Application and ICM Appendixes

(ICM model in excel)

Contents

ICM -1.0 Introduction

As set out in the Filling Requirements, the Incremental Capital Module (ICM) is available to LDCs in the Price Cap IR rate-setting option, which is the rate-setting option chosen by BPI. At this time, BPI is applying for Incremental Capital funding, consistent with the Filing Requirements and the *Report of the OEB on New Policy Options for the Funding of Capital Investments: Supplemental Report* (OEB Case No. EB-2014-0219, released January 22, 2016). The Incremental Capital funding requested is related to BPI's Facility Relocation project, specifically with the incremental capital requirements for its new facility at 150 Savannah Oaks Drive, Brantford ("the Facility" or "Savannah Oaks").

The following table summarizes the ICM funding request, as calculated in BPI's completed ICM moel, included as ICM Appendix G:

ICM Table 1 : Summary of ICM Funding Request		
Total ICM Project Budget (BPI Share)	$	16,133,146.00
Non-ICM Capital Budget	$	4,525,482.00
Total Capital Budget	$	20,658,628.00
Maximum Eligible Incremental Capital	$	14,730,721.84
Incremental Capital Requested	**$**	**14,730,721.84**
Return on Rate Base		
Rate of Return Used		5.98%
Rate Base Additions Requested (average)	$	14,551,424.26
Return on Rate Base	$	870,727.99
Amortization Expense	$	358,595.15
Grossed-Up Taxes/PILS	$	125,739.17
Incremental Revenue Requested	**$**	**1,355,062.32**

The Facility was selected by BPI for its features which will enable BPI to best serve its customers. The selection process was conducted on a set of criteria determined by BPI, however the range of choices that fell within these criteria was relatively limited, though BPI investigated an exhaustive set of real estate options. Please refer to section 2.3 for a more detailed discussion of the selection criteria the options investigated (and pursued).

The incremental revenue requested is not being recovered through other means. BPI has made efforts to reduce the incremental revenue requirement associated with this project and has reflected these reductions by reducing the value of land to be included as well as the components of the facility capital budget to be used by other parties.

In order to take advantage of opportunities for efficiencies and savings to customers, BPI has chosen to share its facility with multiple tenants, including its affiliates Brantford Energy Corporation (BEC) and Brantford Hydro Inc. (BHI) as well as its neighbouring LDC, Energy+, Inc. (Energy+). With the Savannah Oaks Facility, BPI has identified that there will be excess space once the needs of these three tenants are met. As a result, BPI plans to lease the majority of the first floor of the Facility to another tenant or other multiple tenants which are yet to be established.

The following Appendixes are included for supporting evidence:

- ICM Appendix A: 2017 COS Settlement Excerpt ;
- ICM Appendix B: Letter from City of Brantford on Lease Expiry;
- ICM Appendix C: Appraisal of 150 Savannah Oaks Property;
- ICM Appendix D: Draft Floor Plans;
- ICM Appendix E: Consultation Materials;
- ICM Appendix F: Project Timeline; and
- ICM Appendix G: Completed ICM Model (also submitted in Excel format).

ICM-1.1 Bill Impacts

In this Application, BPI is proposing to recover only the Rate Base associated with the portions of the Facility which will be used for BPI's purposes (or an appropriate proportion of those areas which are shared with the other tenants). Details of the mechanisms used to allocate costs to the parties in the facility are outlined below in section 2.8 below. BPI proposes to recover the incremental revenues via a rate rider for each customer class. BPI requests that the Rate Riders for Incremental Capital be effective until its next rebased rates are effective, either following a Cost of Service or Custom IR application. This is currently expected to be January 1, 2022 rates. At its next rebasing, BPI will incorporate the actual capital expenditures associated with its portion of the building into its rate base, and the facility costs will be accounted for through regular distribution rates. The following table sets out the proposed allocation of revenue requirement among the rate classes and the resultant proposed rate riders.

ICM Table 2 : Proposed Allocation and Rate Riders by Class				
Rate Class	**Allocated Revenue Requirement**	**Proposed Rate Rider-Monthly Building Bill Impact**	**Billing Unit**	**Total Bill Impact (Including IRM Adjustments)**
Residential	$ 768,122.60	$ 1.75	per month	3.7%
General Service Less Than 50 kW	$ 134,669.58	$ 3.98	per month	3.3%
General Service 50 to 4,999 kW	$ 411,661.19	$ 70.44	per month	4.5%
Embedded Distributor	$ 14,584.27	$ 1,215.36	per month	0.0%
Sentinel Lighting	$ 2,698.19	$ 0.45	per month	4.9%
Street Lighting	$ 17,531.05	$ 0.25	per month	5.2%
Unmetered Scattered Load	$ 5,795.44	$ 1.18	per month	4.2%
Total	$1,355,062.32			

BPI notes that the total bill impacts for all of the rate classes are well below 10%. The filing Requirements indicate that a distributor must consider rate mitigation measures for any rate class for which total bill impacts exceed 10%. As none of the rate class impacts meet this threshold, BPI has not proposed any rate mitigation measures. As discussed in section 2.5 of this Application, BPI has consulted with customers regarding its facility relocation plan formally on two occasions. Most recently, customers gave "social permission" for BPI to proceed with its facility relocation plans, even when presented with a scenario with a greater overall cost and per-customer bill impacts than those resulting from the proposal in this Application.

BPI has proposed monthly rate riders rather than volumetric rate riders as the facility cost is not related to load or consumption metrics.

ICM-1.2 ICM Requirements

BPI has consulted section 3.3.2 of the Filing Requirements and the listed requirements for an ICM application have been met, as set out below and in the rest of this Application.

ICM-1.2.1 Return on Equity Dead Band

The Filing Requirements indicate that a distributor may not apply for an ICM claim if its regulated return has exceeded 300 basis points above the deemed return on equity embedded in the distributor's rates.

BPI's last Cost of Service Rebasing Application was for 2017 Rates, OEB Case No. EB-2016-0058. In the Decision and Order in this Case, the OEB approved a deemed Return on Equity rate of 8.78%. BPI has remained within the 300 basis point dead band for ROE in both 2017 and 2018, as demonstrated in ICM Table 2 below.

ICM Table 3: Return On Equity Deemed vs. Actual			
	2016	**2017**	**2018**
Approved ROE	8.98%	8.78%	8.78%
Actual ROE	6.53%	11.38%	7.90%
Variance	-2.45%	2.60%	-0.88%

ICM-1.2.2 Rate-Setting Option Selected

The Filing Requirements indicate that distributors with multiple material capital projects should consider a Custom IR Application. BPI does not currently expect to have multiple further projects of the magnitude of the Facility project, and expects that future capital projects should be addressed within the current Distribution System Plan ("DSP") or any future DSPs.

This Application is being completed as a separate ICM Application, rather than as an ICM that follows an approved Advanced Capital Module ("ACM"). Distributors are eligible to apply for Advanced Capital Module funding during a COS application if they believe they can effectively demonstrate that a project meets the OEB's criteria of Materiality, Need and Prudence as set out in the Filing Requirements. BPI has anticipated for some time that it would require funding for its Facility Relocation project. In its 2017 COS Application, BPI had initially included a request for funding for this project; however as BPI was unable to purchase the facility within the timelines required for inclusion in Rate Base, BPI withdrew its request. With unclear prospects regarding the purchase of the Savannah Oaks Facility, BPI pursued its next option, which was the purchase of a green field lot at 79 Garden Ave (the "Garden Ave Facility") and plans to build a new facility. At the time of the 2017 COS Application, BPI reviewed its plans with respect to Garden Avenue Facility, and determined that the project planning was in too early a state to meet the evidentiary requirements for an ACM claim. Please refer to a further discussion of the Facility Relocation project timelines in Section 2.10 below.

ICM-1.2.3 Adjustment to ICM Threshold

In the Settlement Agreement to BPI's 2017 Cost of Service Application (EB-2016-0058), BPI agreed to an adjustment applicable to future ICM applications related to the in-service additions for the Bridge Year (2016) and Test Year (2017) as approved in that Application.

BPI agreed to increase the ICM threshold in a future facility ICM application by an amount equal to any actual under-spending compared to the approved in-service capital additions for 2016 and 2017, with an adjustment of 50% applying to the 2017 additions (meant to account for the application of the half year rule to test year additions). The relevant excerpt from BPI's Decision and Order in EB-2016-0058 is attached as ICM Appendix A.

The table below compares BPI's approved Capital Additions for 2016 and 2017 to the actual capital additions in those years, however as there was no under-spending compared to the COS approved numbers, no adjustment is necessary.

ICM Table 4: Return On Equity Deemed vs. Actual		
	2016	2017
Approved In-Service Additions (net of Capital Contributions)	$ 3,596,698.00	$ 3,828,988.00
Actual In-Service Additions (net of Capital Contributions)	$ 4,076,072.00	$ 3,833,285.19
Variance	$ 479,374.00	$ 4,297.19
Amount under-spent	$ -	$ -
50% adjustment for 2017	N/A	$ -
Total Threshold Adjustment Required:		$ -

ICM-1.2.4 Inputs into the ICM Model

Please note, BPI 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, BPI 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, BPI has calculated CCA related to the building using the methodology applicable for additions prior to November 20, 2018. Consistent with the letter, BPI expects the OEB will address the appropriate treatment of the accelerated CCA impact at BPI's next cost-based rate application. BPI currently expects this to be its 2022 Cost of Service rate application.

ICM-1.2.5 Incremental Nature of Project

BPI has completed the OEB's ICM Model, which confirms the amount of $15,168,618 in capital additions is incremental to BPI's financial capacities underpinned in the existing rates.

The application of the Threshold Test is set out below:

ICM Table 5: Threshold Calculation		
2020 Generic Capital Additions	$ 4,525,482	A
2020 ICM Facility Project Addiitons	$ 16,133,146	B
2020 In Service Additions	$ 20,658,628	C=A+B
ICM Treshold	$ 5,927,906	D
Incremental Eligible Amount	$ 14,730,722	E=C-D
2020 ICM Capital Additions Proposed	$ 14,730,722	F=min(E,B)

ICM-1.2.6 Non-Discretionary Project

As set out in the Filing Requirements, LDCs no longer need to demonstrate that a project is non-discretionary in order to be eligible for an ICM claim. Regardless, BPI's facility relocation is required and non-discretionary as the three current facilities being rented or leased will no longer be available after 2022. Please see Section 2.2 for a further discussion of future unavailability of the existing locations.

ICM-1.2.7 Need

BPI believes the Facility project meets the evidentiary requirements to demonstrate need on the following basis:

- The existing facilities leased or rented from the City of Brantford will no longer be available to BPI after 2022.
- The current arrangement, with departments located across three locations has created challenges and inefficiencies for BPI;
- The working conditions at the existing locations are sub-optimal and have the potential to limit productivity, corporate culture and employee engagement;
- There are operational improvements to be achieved through re-location to one central facility with improved functionality.

The sections below will further discuss each of these items.

Impact of Disallowing ICM Funding

The filing requirements indicate that the LDC must include a description of the steps that a distributor would take in the event that the OEB does not approve the application. Should the OEB not approve the funding proposal, BPI would not have opportunities to make any substantial changes to the project plan. BPI needs to find a new facility as its current arrangements are will no longer be available. The facility has been purchased, and the investments to be made for the refurbishment of the existing space and the building of the new garages are necessary for the operation of the utility. BPI has investigated other options for housing its operations and determined this is the best and most cost effective available option, so there are no options which would enable a more cost-effective operation of the utility. As a result, BPI would maintain its current planning with respect to new expenses, but have no opportunity for funding them if the OEB were to disallow funding. This would have a significant impact on the financial position of the company, likely pushing BPI's deemed ROE outside (below) the 300 basis-point dead band.

The following table outlines the impact to deemed ROE of not approving the ICM claim, with the assumption that the deemed ROE is the achieved ROE in the year, with the exception of the capital costs associated with the facility.

ICM Table 6: ICM Impact on ROE if not Approved		
Deemed Rate Base underpinning Rates	$	74,382,897.03
Incremental Capital to Rate Base	$	16,133,146.00
Estimated Adjusted Rate Base	$	90,516,043.03
Deemed Return on Equity		8.78%
Deemed Equity Component of Capital Str		40%
Expected Deemed ROE	$	2,612,327.34
Proposed Incremental Capital Funding--assumed loss if ICM is not approved	$	1,355,062.32
Anticipated Return if ICM is not Approved	$	1,257,265.02
Anticipated Achieved ROE		4.23%
Variance from Deemed ROE		-4.55%

As shown above, the proposed funding will make a significant impact to the financial position of the utility. If BPI does not receive approval for the funding requested, the financial results for 2020 are likely to be below 300 basis points from BPI's deemed ROE. If this is the case, and given the critical nature of this funding, BPI may seek to undertake an "early" rebasing in 2021 in an attempt to re-balance the rate revenue to a level that does not put the company at risk. BPI may have to re-assess its listing of projects for the coming years to identify whether other programs can be deferred, reduced or canceled.

ICM-1.2.8 Prudence

BPI believes it has adequately met the requirements related to prudence. Throughout the process, BPI has undertaken due diligence steps in consultation with qualified third parties and under the guidance and oversight of its Board of Directors. The following items demonstrate BPI's prudence in its planning for its Facility Relocation.

- BPI's project charter for the project includes consideration of ratepayer interests, and proving value for money, long-term durability.
- Beginning in February 2015, BPI investigated over 50 opportunities for its facility relocation against a set of reasonable criteria for need;
- BPI selected the option with the best value for customers;
- BPI made several further arrangements with other parties to mitigate project cost and improve the customer benefits of the project.
- BPI's proposal for rate base additions takes into account only the components of the facility which will be used to the benefits of BPI's ratepayers.

- BPI has taken its time to ensure the project with the best value for customers is selected
- BPI has enlisted the assistance of qualified professionals at various stages throughout the planning and selection process.
- BPI reviewed its options with customers and received social permission for its plans.
- The facility compares favourably against other utility facility benchmarking, despite increasing cost pressures.
- BPI has consulted with its customers regarding its facility relocation plans multiple times and has received "social permission" to continue with its plans.
- BPI has taken an innovative approach to its facility relocation in order to take advantage of the opportunity it saw with the Savannah Oaks building.
- The appraised value of the facility, as determined by a third party independent evaluator, indicates BPI has purchased its facility for a price lower than the market value by $900,000.
- BPI has made further adjustments and arrangements to best use the selected property.

ICM-1.2.9 Materiality

BPI's Savannah Oaks project is a major capital expenditure which is incremental to the capital expenditures included in BPI's rates. The project clearly exceeds the ICM materiality threshold calculated in the **ICM Model,** which is $5,927,906.

BPI's budget for Capital additions in 2020 is $4,525,482. This represents an increase over the 2020 DSP amount of roughly $1M. 2020 is the fourth year of the forecast period in BPI's most recently approved DSP, which was developed primarily in 2015 based on the best known information at that time. As a result of changing assumptions, new information, and shifts in the priority needs there have been variances from the DSP to actual capital additions, with actuals exceeding the DSP in the most recent three years. This trend is forecast to continue into 2019 and 2020.

ICM Table 7: DSP Variance Analysis

	2016	2017	2018*	2019	2020
DSP Amount	$ 3,596,698	$ 3,828,988	$ 3,726,313	$ 5,337,654	$ 3,481,441
Actual Spending	$ 4,076,072	$ 3,833,285	$ 4,322,647	N/A	N/A
Budgeted Spending	N/A	N/A	N/A	$ 5,819,919	$ 4,525,482
Variance- DSP to Actual	$ 479,374	$ 4,297	$ 596,334	N/A	N/A
Variance- DSP to Budget	N/A	N/A	N/A	$ 482,265	$ 1,044,041

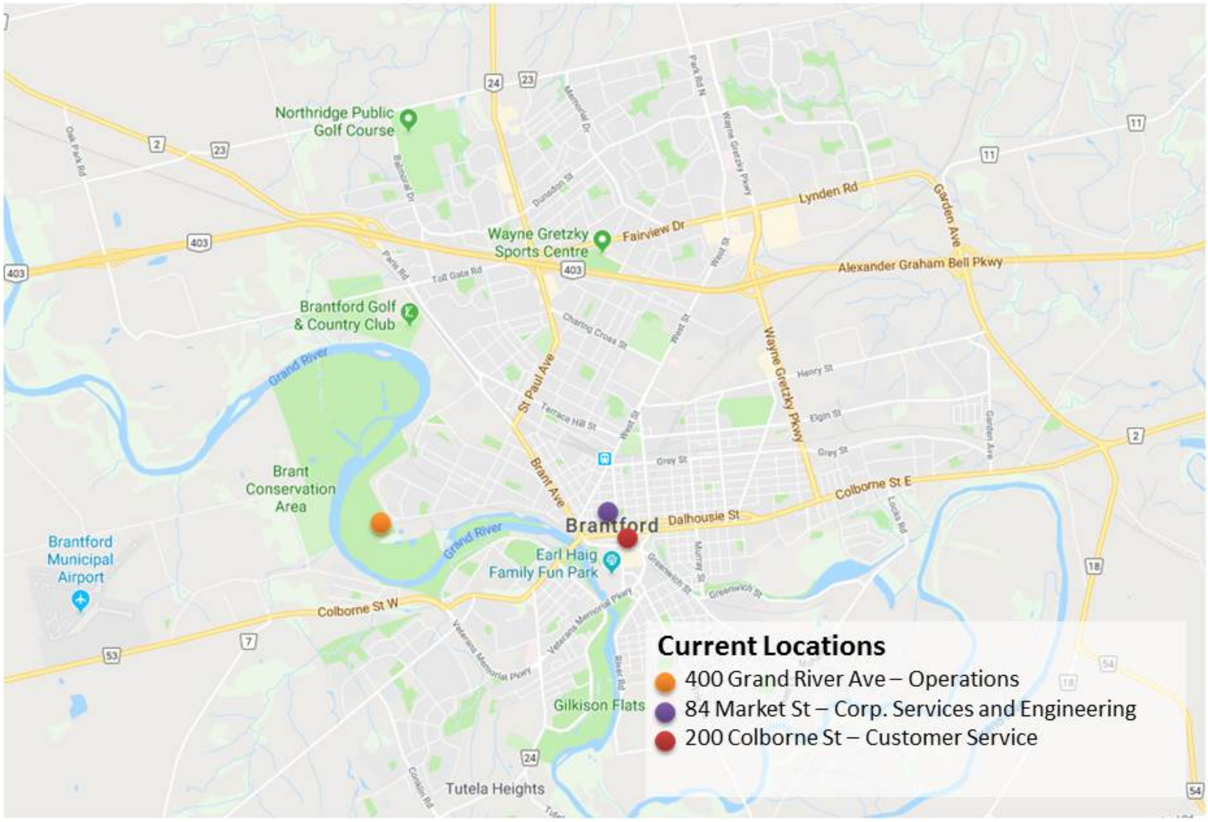
** 2018 DSP included the HONI Switches project worth $3,752,548.*
This project was identified as uncertain in the DSP and subject to an ICM if it occurred.
Therefore BPI has removed the associated spending from the "DSP Amount" Value

The increase in 2020 budgeted spending is attributed to increases in the replacements of poles, vaults and junction boxes identified through asset inspections. Additionally, an increase to the vehicle replacement budget is required as a result of the need to replace a large bucket truck. The 2020 budget also includes a new project focused on system modernization and automation. Increases due to the deferral of the OMS project are also included. These are offset by decreases to the System Access category as a result of lower than forecast new services and other third party projects.

ICM-2.0 Project Overview

ICM-2.1 Description of Current Facilities

Currently, BPI employees operate out of three locations within Brantford. BPI rents facilities from the City of Brantford in two downtown administrative office locations- 84 Market Street and 220 Colborne Street and a third operations centre (400 Grand River) which is used for vehicle and materials storage, in addition to housing certain departments. Each of these locations also houses City of Brantford Departments, and in many cases BPI shares common spaces with the City of Brantford. The map below indicates the locations within Brantford of each facility.


Current Locations
400 Grand River Ave – Operations
84 Market St – Corp. Services and Engineering
200 Colborne St – Customer Service
Northridge Public Golf Course
Wayne Gretzky Sports Centre
Brantford Golf & Country Club
Brant Conservation Area
Brantford Municipal Airport
Brantford
Earl Haig Family Fun Park
Gilkison Flats
Tutela Heights
Grand River
Lynden Rd
Fairview Dr
Alexander Graham Bell Pkwy
Garden Ave
Wayne Gretzky Pkwy
St Paul Ave
Brant Ave
Dalhousie St
Colborne St E
Colborne St W

The table below shows the departments and headcount at each location:

ICM Table 8: Headcount at Each Location

Location/Department	Headcount (2019)
84 Market St.	
● Engineering *	5
● Senior Leadership/Administrative*	4
● Finance	6
● Information Technology	2
● Regulatory	3
● Communications	1
● Human Resources	2
84 Market St. Total	**23**
220 Colborne St.	
● Billing and Settlement	6
● Customer Care / Cashiers	11
● Conservation and Demand Managemen	2
220 Colborne St. Total	**19**
400 Grand River Ave.	
● Operations	17
● Stores/ Dispatcher	1
● Engineering - SCADA	2
● Metering	2
● Senior Leadership/Administrative*	1
● Engineering *	1
400 Grand River Ave. Total	**24**

* The VP of Engineering and Operations and the Senior Manager of Engineeing and Operations have offices at both 84 Market St. and 400 Grand River Ave and have been included in both counts

ICM-2.2 Need for Relocation

Future Availability of Current Arrangements

BPI currently rents or leases its three locations from the City of Brantford under a Shared Services Agreement (SSA). The current SSA lasts until January 1, 2022 and BPI has been advised by the City of Brantford that the lease and rental arrangements will not be renewed upon the expiry of the current SSA. ICM Appendix B is a letter dated January 11, 2018 from the City of Brantford which confirms the spaces currently used by Brantford Power will not be available in 2022, as the City will not be renewing the existing leases.

This is the primary driver of BPI's relocation as it renders the relocation non-discretionary.

BPI has been aware that the non-renewal of the leases was a risk as early as 2014, BPI has understood that the City would be reviewing its plans for its facilities as part of its Facilities Accommodation Study. At this time, the City of Brantford has already sold 220 Colborne, and has recently announced plans to sell 84 Market Street.

Inefficiencies of Space and Opportunities for Improved Service

Availability of Space and Sub Optimal Working Conditions

While the lease and rental arrangements with the City of Brantford have been suitable for BPI's needs for many years, there are many factors which affect the suitability of the current facility configuration and which render the current arrangements sub-optimal, even if continuation of these arrangements was an option.

As both BPI and the City have experienced organizational change and growth in past years, this has led to constraints in some of the space allocations which were previously suitable. In addition to space limitation at some locations, the current configuration limits the flexibility of working spaces.

BPI has been presented with difficulties in locating certain departments together. Currently, executives and senior managers often have staff working at different locations and are required to travel and split their time between these locations.

Meeting rooms have presented an additional challenge. BPI has access to only one meeting room which it has exclusive use of. Other meeting rooms are available on the basis of reservations, on a first-come, first-served basis. There are three such meeting rooms, one at each location. As many managers do not have private offices, these "shared" meeting rooms are sometimes required for two-person meetings or even reserved for use for phone calls which may require sensitive discussions.

None of the meeting rooms is large enough to accommodate all BPI employees, and therefore any all-staff meetings must be held off site and require greater planning.

In 2017 and 2018, BPI's CIS project required several weeks of training sessions, often led by BPI's CIS provider, with training provided to almost every employee in the company. BPI had significant difficulties arranging for space for this crucial training.

Each of the facilities in use by BPI has its own challenges. The space at 220 Colborne is the most challenging of the configurations, as space is very limited and there is only one meeting room with limited availability as it is shared with various City of Brantford departments. Furthermore, the rest room facilities at this location are under-sized, with only one available washroom which is shared with other City of Brantford departments. The customer service offices at this location are at the basement levels, and as a result there are no windows or access to daylight.

The space at 84 Market Street has an abundance of space per employee, however due to the stationary nature of the space (closed, walled rooms rather than open concept design), there is limited flexibility in the allocation of space among employees and departments. The current arrangements have resulted in some inefficiencies, including splitting up departments between multiple rooms as well as a lack of private offices. Several Managers and even Vice Presidents have cubicle style offices within a larger department office, and private rooms for sensitive discussions and phone calls are limited to the two meeting rooms- one shared with the City and one exclusive to BPI. There have been issues with the heating and cooling systems at this location. For example during the 2018/2019 winter season, the heat did not work in some offices for several weeks, requiring the purchase of many space heaters to keep work spaces at functional temperatures.

At 220 Colborne and 84 Market, BPI has made adjustments more and more frequently to address departmental changes as well as special projects. Staff have moved from 220 Colborne to 84 Market and back as a result of a need to co-locate project leaders for BPI’s recent CIS and FIS implementation projects. These types of changes have sometimes required that spaces designed for single use are occupied by multiple employees

Parking at the 220 Colborne and 84 Market locations is limited and BPI is required to rent parking spaces from nearby lots. The recent sale of one of these lots resulted in BPI struggling to make alternate arrangements for 12+ new spaces, at double the previous cost. Parking for employees located at 220 Colborne is situated in a closed parking garage, located away from the offices and requires employees to walk through garages which are sometimes empty at various hours of the day. Dedicated visitor parking is not available at these locations.

With respect to 400 Grand River, the garages are currently shared with City of Brantford Transit, and as of more recently, with GO bus services. The benefits of these sharing arrangements include access to maintenance services and increased security arrangements. Despite this, the garages are currently full, and there is no longer space to store trailers and metering trucks inside. As a result of the crowdedness, after-hour responses which require full deployment may be somewhat delayed. Additionally, the storage of vehicles outside can delay start up time during the winter, as there is additional need to de-ice and warm up equipment.

The meeting and office facilities at 400 Grand River Ave. include some of the same limitations as the office space at 84 Market and 220 Colborne Street. There is only one meeting room which is shared with the City of Brantford functions, as a result, there is an added difficulty when scheduling meetings. The facilities (heating, air conditioning and rest rooms) at this location often malfunction. Additionally, the sole meeting room is located adjacent to the main loading doors, so meetings can be frequently disrupted due to noise.

Inefficiency of Three Locations

BPI’s current arrangement of having its staff and operations split among three locations has been one of the longest-running issues. While BPI has made the most of the available locations, and has typically located the most related departments near one another, there are certain inefficiencies by having other departments separated. These include additional costs or effort to do the same work or missed opportunities for improved output. These include the following:

- Work time spent on travel between locations rather than productive work;
- Missed opportunities for synergies by having related functions located apart from one another;
- Inability to quickly assemble the full staff in one space for company-wide announcements or training (instead key staff need to travel to each of the three locations and hold separate meetings for corporate updates, HR programming, etc.);
- Inability to hold all-staff meetings in an on-site location;
    - These meetings are held on a quarterly basis as a result of the logistical difficulties with assembling staff; however there are times where a greater frequency of meetings would be ideal.
- Impacts to corporate culture as a result of “silos”—lost opportunities for all staff to interact;
- Feedback related to the “silo” effect or other negative impacts of having separate locations is consistently present on BPI’s employee engagement survey responses.
- Lost efficiencies and increased costs related to employee wellness programs;
- Face-to-face meetings can be difficult to arrange:
    - holding cross functional meetings can require driving time, mileage, increased disruption;
    - holding conference calls can require conference call costs as well as lost efficacy of communication (limited access to visuals, cross-talk, etc);
    - lower priority discussions may be skipped altogether.

In 2018 BPI undertook an internal, informal survey to attempt to quantify the impacts of some of these inefficiencies. The survey asked employees to estimate the number of trips taken between each location over the course of a year, as well as providing an opportunity to give verbatim feedback on other difficulties associated with the three-location accommodation. The following table estimates the annual value of some of the items identified through the responses to this survey.

Certain assumptions have been made for the purpose of the estimates, including use of an average wage rate as well as proration to adjust for the response rate. Please note, though estimates of mileage cost have been included, it is common that staff do not claim mileage for trips between locations. Similarly, reduced travel time would not result in cost savings to BPI, however there would be an expected increase in the productivity (work product) of the associated person-hours.

ICM Table 9: Cost Inefficiencies of Three Locations		
	Annual Estimated Cost	
Quarterly Meetings - Travel, mileage, rentals, catering	$	12,660.19
Conference Room Rental	$	1,100.00
Duplication of office for VP Eng/Ops	$	5,500.00
Conference Call fees	$	12,960.00
Double Parking	$	1,500.00
Travel and mileage for regular trips (survey)	$	55,577.45
2018 Move Costs	$	28,135.50
Workplace Safety Inspections	$	2,880.00
TOTAL	$	120,313.13

Included in the amount above are "2018 Move Costs" which are the costs to reorganize some of the space at 84 Market Street and 220 Colborne Street to enable the CIS project team to be located together. With this move, BPI also consolidated the Finance and Regulatory departments into one office each, and to create an additional, BPI-exclusive meeting room at 84 Market.

Safety and Emergency Preparedness

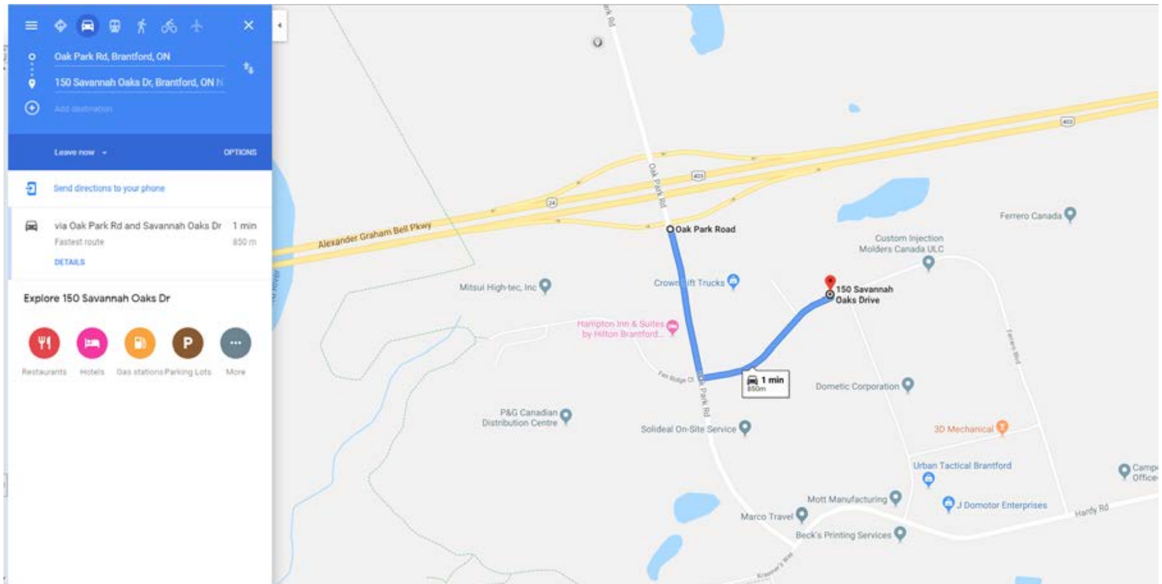
One of the key risks associated with the current configuration of space is that 400 Grand River Ave. is on a flood plain. In the case of a weather related emergency, BPI is expected to be one of the key agencies responding to customer needs. With is operations on a flood plain, there is an increased risk that the key equipment required for a response to a flood situation is unavailable because it is affected by the same weather event.

BPI has taken steps to mitigate the risks associated with flooding, and monitors water levels near its operations center during periods of thawing or high precipitation. BPI has Mobile Control Center that is fully equipped to be used during periods when operations center may need to be evacuated due to any emergency conditions. Removal of key equipment and evacuation of personnel is executable if emergency evacuation of the operations center is required, and third party assistance agreements exist which would enable BPI to access the required resources in an emergency situation.

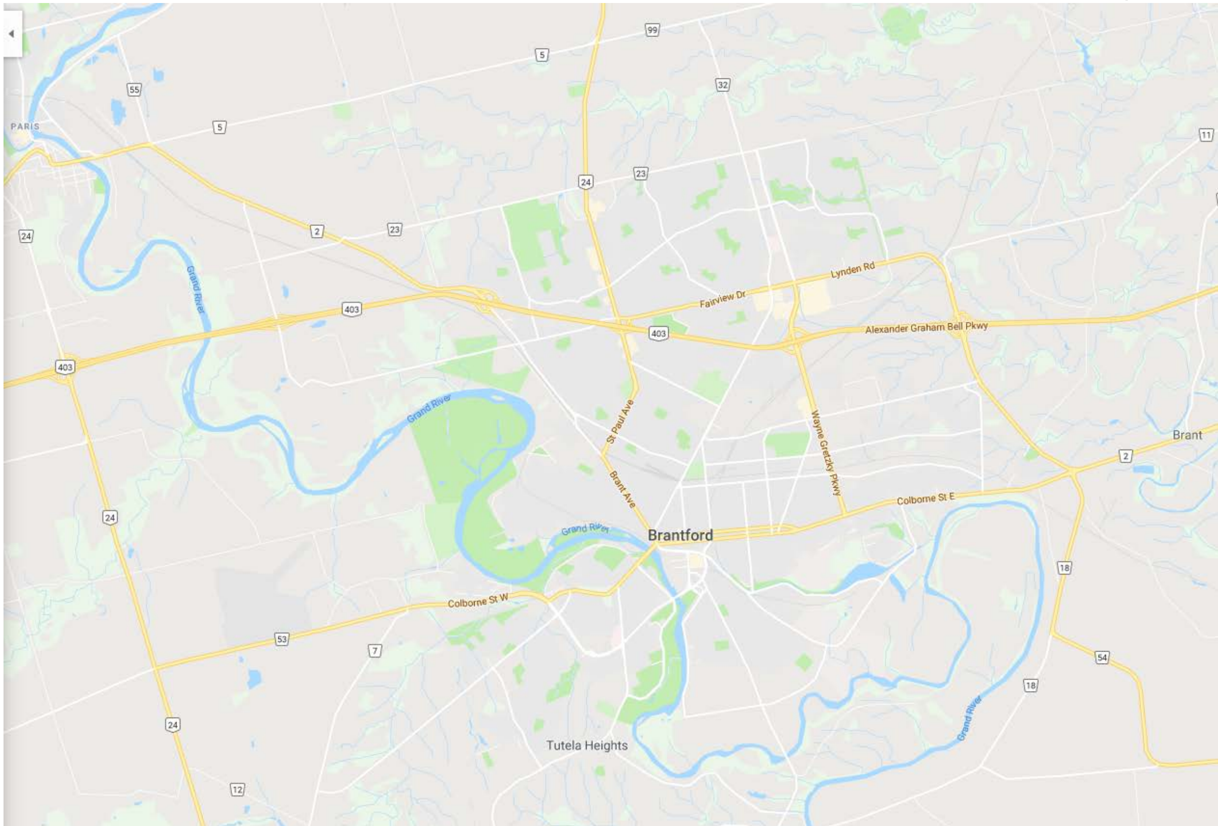
In February 2018, the City of Brantford did encounter a serious flooding event, with significant flooding in the Grand River requiring the City to declare a State of Emergency. BPI was required to evacuate the space at 400 Grand River Ave. and used its Mobile Command Center for Operations. No permanent damage to the facility or BPI's assets occurred as a result of the flooding, despite the evacuation.

Response Times and Access to Service Territory

In determining the criteria for its new location, BPI searched for a facility which would be close to major thoroughfares. While the Operations centre at 400 Grand River Ave. is relatively central within Brantford, it is located at the edge of a neighbourhood with primarily residential usage. BPI crews need to pass through residential and school areas with relatively low speed limits and many stop signs. The new location at 150 Savannah Oaks Drive is less than a minute from the entrance ramp onto Highway 403 (maximum speed: 100 km/hr).



From Highway 403, BPI’s vehicles can quickly access connected higher-speed local roadways such as Wayne Gretzky Parkway, St. Paul Ave. and Garden Ave which are multi-lane North-South roads with speed limits ranging 60-80 km/h, and Fairview Drive and Colborne Street which are similar East-West roads. From 400 Grand Rive Ave, it is 5-6 minutes to access the nearest intersections in this NS-EW grid of major Brantford thoroughfares.



As a result, BPI anticipates that outage response times and access to regular work will be enhanced as a result of this relocation. This assessment will be dependent on the geographical patterns for sources and frequency of outages and regular work, which can vary significantly year over year.

ICM-2.3 Description of Selection Process

In 2014 BPI initiated its search for a new, consolidated facility. Search criteria were developed based on an assessment of BPI's current and long-term needs, and the following requirements were determined:

1. **Location:** Facility must be within current service area i.e. within the City of Branford;
2. **Time to occupancy**: Consider currently available options with preference for existing buildings for repurposing vs. pursuing new build options (confirmed as a customer preference expressed in our Customer Engagement Activities) ;
3. **Cost:** Appropriateness of gross acquisition cost;
4. **Lot Size:** Overall lot size meets space needs assessment report; and
5. **Building profile**: The building footprint must allow for the following elements:
    - Office space component;
    - Warehouse area;
    - Truck and vehicle movement; and
    - Outdoor storage.

In order to determine the appropriate amount of space required for each usage type (office, warehouse, yard, storage), BPI engaged AECOM to develop a recommendation regarding appropriate ranges of space for BPI's needs. In this AECOM report, a Concept Site Plan was developed based on an illustrative new build facility, which incorporated minimum space requirements with a new build greenfield scenario. It was understood that any real properties considered, whether greenfield or existing facility, would require further review site planning, as the specifics of each property or building would impute limitations to flexibility of design. The design incorporated a relatively small allocation of office space per employee, specifically 80 square feet on average.

The following listing outlines the space requirements developed by AECOM to assist BPI in determining the minimum space requirements for a stand-alone BPI building.

- Minimum of 6.8 to 8.3 Acres of space, depending on the consolidation of outdoor storage needs.
- Minimum square footage of 37,000 square feet
    - Approximately 16,000 square feet of office space,
    - 7,500 square feet for warehouse
    - 13,500 square feet of vehicle storage;

Beginning in February 2015, BPI worked with CBRE Group Inc. ("CBRE") to review the vacant land and existing properties for sale in Brantford which could suit BPI's needs. The nature of BPI's relatively dense, urban service territory resulted in somewhat limited commercial and industrial properties which would suite BPI's needs. BPI's service territory includes limited developable land and properties for sale.

CBRE and BPI reviewed 17 property descriptions, 12 of which were existing buildings and 5 of which were greenfield/land. While none of the properties met all of BPI's criteria, BPI chose two existing buildings which were the closest to meeting the key requirements for further investigation, one of which was the facility at 150 Savannah Oaks. Both facilities would require additional construction to be made suitable to BPI's needs.

With respect to the option to continue to lease property, BPI consulted with its real estate experts and understood that most properties listed on the market could either be purchased or leased. BPI considers the ownership of a facility as a more attractive option. This is in part as a result of the increased control and certainty associated with owning rather than leasing a building- the price and availability of a leased facility is only in place for the duration of the current lease contract. BPI understands a typical lease contract lasts a maximum of five years and does not provide a reasonable level of long term business certainty.

Further, in a lease scenario BPI would not have been able to take advantage of its partnerships and other efficiency opportunities, as well as in-housing such services as vehicle maintenance and fuel services which require long term certainty and control of property.

BPI did not want to be subject to cost fluctuations or to the potential of another relocation project as a result of landlord decisions. Additionally, BPI's expectation, and some preliminary analyses indicated that, for the same hypothetical facility, a lease would be more costly than ownership.

BPI requested that AECOM further analyze these two sites. AECOM provided an analysis on both sites, which identified that one site did not have sufficient warehousing, storage and yard space to meet BPI's requirements. 150 Savannah Oaks was determined to be a feasible option for BPI. Due to the expected relative price and timing benefits associated with refurbishing an existing facility, as compared to a new build on vacant land, BPI pursued the purchase of Savannah Oaks beginning in February 2015. The facility met all of the minimum space criteria as well as scoring favorably in the total cost, cost per square foot, location, and timing considerations.

As the negotiations for Savannah Oaks went forth, BPI continued to investigate other options with CBRE, including:

- 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.

In November 2016, CBRE identified a greenfield property located at Garden Ave in Brantford which had certain advantages. With little progress on the "Plan A" purchase of the facility at 150 Savannah Oaks, and no existing facilities meeting BPI's requirements, BPI reverted to "Plan B" and purchased the 9.9 Acre property on Garden Ave in January of 2017.

BPI worked with AECOM to complete further planning on the Garden Avenue property, first for a stand-alone building for BPI, and then for a shared facility with Energy+. In June 2017 BPI engaged a project manager for its facility relocation project, and in September 2017, a Design Consultant was selected to further detail BPI and its tenants' requirements and develop architectural drawings for the new build facility. The design consultant reviewed the initial requirements of each party and further detailed the new requirements at the new facility, as well as developing a design based on the requirements for a new build facility (building code, AODA compliance, etc).

The facility had the goal of optimizing value for BPI and its customers by acquiring a facility which would be durable and practical and able to meet long term needs without design elements or finishes which would drive up costs for no incremental value. Throughout the design process, BPI undertook several steps to reduce overall project costs, including eliminating some items from scope (for example, the pursuit of LEED certification and space reductions to the shared operations area).

In late 2018, BPI issued an RFP for a builder for the facility at Garden Ave, with a cap on the bids of $27M for the construction of the facility only. Additional project including soft costs, permits and fees, and furniture, fixtures and equipment ("FF&E") would bring the total project cost to $32M. This cap was based on assessments at a Class C level from the design consultant, verified by cost consultants, and represented the maximum price BPI would pay for the new build budget, with the expectation that the resultant bids would be lower than this cap.

BPI did not receive any bids on its RFP. In follow up consultation with the firms which reviewed the RFP, the informal feedback indicated that the cap on the project was too low to make the project commercially attractive.

The following tables show a breakdown of the project budget for Garden Avenue, with the associated allocations of space and cost to the parties. As discussed above, please note the lack of response to BPI's RFP may indicate this project budget was too low.

ICM Table 10-A Garden Ave. Project Budget

	Projected Cost (Class C Estimate)	
Construction and Soft Costs	$	29,039,398
Land	$	1,677,792
Building Capital Cost	**$**	**30,717,190**
Furniture, Fixtures and Equipment	$	1,222,500

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**

ICM Table 10-C Garden Ave. Fully Allocated- Allocation of Space & Costs

	Square Feet	Cost	
BPI (with 50% of Shared Space)	42,066	$	19,704,201
Energy+(with 50% of Shared Space)	19,516	$	9,543,404
Affiliates	2,906	$	1,469,585
Total Space	**64,487**	**$**	**30,717,190**

ICM Table 10- D Garden Ave. BPI Estimated Rate Impact		
	Cost	
Fully Allocated BPI Cost	$	19,704,201
Add: FFF&E Allocated to BPI	$	820,500.00
Total Capital Additions	**$**	**20,524,701**
Estimated Annual Incremental Revenue Requirement:	**$**	**1,872,357**

Also in late 2018, there was a renewed interest from the seller at 150 Savannah Oaks in BPI's purchase of the property. Facing an unaffordable new-build, BPI took time to re-assess and perform further due diligence on the Savannah Oaks option. Following an assessment of the scenarios at each location, BPI took the opportunity for the relatively inexpensive existing building, reverting back to its "Plan A". BPI purchased the facility in February of 2019.

BPI has since worked 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 existing facility at 150 Savannah Oaks where possible, resulting in a Class D estimate for the new construction and refurbishment elements of the project, and draft designs for the new build portions and allocation of space for the existing buildings.

BPI has recently secured a construction manager for the project, and is in the process of engaging a design consultant, with the retention of sub-trades to follow.

The comparative statistics for the Savannah Oaks project are listed below, showing that the total project cost, as well as the cost for BPI's components of the facility, will be lower at Savannah Oaks.

ICM Table 11-A Savannah Oaks Project Budget		
	Projected Cost - Total Building	
Construction, Soft Costs, Permits and Fees	$	19,714,948
Land and Building	$	8,670,102
Building Capital Cost	**$**	**28,385,050**
Furniture, Fixtures and Equipment	$	551,000
Total Proposed Budget	**$**	**28,936,050**

ICM Table 11-B Savannah Oaks Allocation of Space & Costs				
	Square Feet	Cost	Allocation of Shared Space	% of non-common Space (Sqft)
BPI	51,849	$ 10,544,673	62,165	53.8%
Energy+	14,229	$ 4,395,862	24,545	21.2%
Shared - BPI and Energy+	20,632	$ 8,425,010	-	0.0%
Common - all parties	15,957	$ 1,786,706	15,957	0.0%
Affiliate	3,154	$ 353,154	3,154	2.7%
Tenant 3	25,718	$ 2,879,646	25,718	22.3%
Total Space	**131,539**	**$ 28,385,050**	131,539	100.0%

ICM Table 11-C Savannah Oaks Fully Allocated- Allocation of Space & Costs		
	Square Feet	Cost
BPI	70,747	$ 15,718,146
Energy+	27,934	$ 8,987,792
Affiliate	3,589	$ 401,909
Tenant 3	29,269	$ 3,277,204
Total Space	**131,539**	**$ 28,385,050**

ICM Table 11- D Savannah Oaks BPI Estimated Rate Impact	
	Cost
Fully Allocated BPI Cost	$ 15,718,146
Add: FFF&E Allocated to BPI	$ 415,000.00
Total Proposed Incremental Capital Additions- BPI Portion only	**$ 16,133,146**
Proposed Annual Incremental Revenue Requirement:	**$ 1,355,062**

As shown in the tables above, the total project budget at the Savannah Oaks facility is lower than the minimum estimate of the Garden Avenue project. The incremental revenue requirement associated with the Savannah Oaks option is almost $500k lower per year.

ICM-2.4 Benchmarking

Throughout the process of searching for a new facility, BPI has kept affordability and value for money as some of the key consideration points. BPI understands there are several comparable applications for the OEB's review of other LDCs' facility planning. In the table below, BPI has presented building application outcomes as compared to the portion of the Savannah Oaks building being proposed for incremental capital.

ICM Table #12: Facility Benchmarking Comparison

LDC	Milton Hydro	Waterloo North	Innisfil Hydro	PUC Hydro	Energy + *	Enersource	PowerStream	Brantford Power Inc. - Savannah Oaks	Brantford Power Inc- Garden Ave. Scenario
Function	Administration & Operations	Administration & Operations	Administration & Operations	Administration & Operations	Administration	Administration	Administration	**Administration & Operations**	Administration & Operations
Custom Bulid Vs. Purchase and Refurbish	Purchase and Refurbish	Custom Build	Custom Build	Custom Build	Purchase and Refurbish	Purchase and Refurbish	Custom Build	**Purchase and Refurbish**	Custom Build
Application Number	EB2015-0089	EB-2010-0144 EB-2015-0108	EB-2014-0086	EB- 2012-0162	EB-2018-0028	EB-2012-0033	EB-2008-0244	**EB-2019-0022**	N/A- Comparison Only
Building In-service year	2015	2011	2015	2012	2022	2012	2008	**2020**	2020
Application Year	2016	2011	2015	2013	2019	2012	2009	**2019**	
Capital Cost	$14,460,000	$26,476,961	$13,246,704	$23,500,000	$8,100,000	$20,000,000	$27,700,000	**$16,133,146**	$20,524,701
Capital Approved by OEB	$12,557,798.00	$25,882,961.00	$10,896,704.00	$22,916,497.00	$6,567,000.00	$18,000,000	$27,700,000	**$16,133,146**	$ 20,524,701.01
OEB Approved Capital with Inflationary Impact	$ 13,688,635	$ 30,211,282	$ 11,877,959	$ 25,811,280	$ 6,567,000	$ 20,598,117	$ 33,178,279	**$ 16,133,146**	$ 20,524,701
Customers	36,818	56,230	16,443	33,000	65,970	204,728	364,505	**39,904**	39,904
Square Footage	91,828	105,000	36,172	110,382	21,892	79,000	92,000	**70,747**	42,066
FTEs	61.5	125	41	87	135	150	250	**63.3**	63.3
Gross Square Feet per Employee	1,493	840	882	1,269	N/A	N/A	N/A	**1,118**	665
Capital Cost Per Employee with Inflationary Impact	$ 222,579	$ 241,690	$ 289,706	$ 296,681	$ 48,644	$ 137,321	$ 132,713	**$ 254,868**	$ 324,245
Cost per Customer With Inflationary Impact	$ 372	$ 537	$ 722	$ 782	$ 100	$ 101	$ 91	**$ 404**	$ 514
Capital Cost Per Gross Square Foot with Inflationary Impact	$ 149	$ 288	$ 328	$ 234	$ 300	$ 261	$ 361	**$ 228**	$ 488
LDC	Milton Hydro	Waterloo North	Innisfil Hydro	PUC Hydro	Energy +	Enersource	PowerStream	BPI - Proposed	BPI - "Plan B"
Captial Cost Per Gross Square Foot with Inflationary Impact	$149.07	$287.73	$328.37	$233.84	$299.97	$260.74	$360.63	**$228.04**	$487.92

**Please note the Energy+ Application originally requested $8.1M and is currently the subject of a motion to review.*

BPI has also presented the equivalent costs which would have been proposed for incremental capital treatment under the Garden Avenue scenario. As described above, the Garden Avenue scenario represents the next best available option for BPI's relocation and therefore provides a good comparison.

Through discussions with its real estate and construction consultants, BPI understands that price changes in these sectors over the recent past have trended higher than typical inflation. BPI has used the OEB's inflation values to inflate the capital costs of the benchmarking comparators based on the in-service year of each facility. As BPI's facility proposal is for an in-service date occurring in 2020, a forecasted inflation factor of 2.0% was used based on the most recent available CANSIM data and the OEB's methodology for setting its annual IPI.

BPI has presented the OEB-approved capital additions in the chart below. Almost all of the comparators presented had a lower level of cost approved for capital additions. Therefore, it is worth noting that the capital additions do not necessarily indicate levels of actual cost for a facility project, and it is possible they may not represent achievable levels of cost.

BPI notes that Hydro Ottawa also has had a relatively recent facility plan approved by the OEB. Due to the characteristics of Hydro Ottawa as well as its facility plan, BPI has excluded it from the benchmarking analysis due to the size of both the project and the LDC. BPI does not believe the Hydro Ottawa facility would have been a relevant comparator.

Comparators

Some of the key drivers for the cost of a project of this nature can be the nature of the space – Administrative and Operations spaces can have different costs—and whether the facility is a custom build or the purchase and refurbish of an existing facility. BPI's proposed facility is for both Operations and Administrative purposes and is a purchase and refurbish project, however there are some significant new-build elements to the project, namely the construction of the new garages. Four other facilities are similar in function, while three others were also Purchase and Refurbish.

BPI Proposal – Benchmarking Comparison

BPI's Savannah Oaks proposal has the second lowest capital cost per square foot among its comparators. This is due in part to BPI's attention to keeping the overall project budget affordable, and efforts to mitigate the cost to customers, including the exclusion of the value of severable land, and the sharing of fixed costs with BPI's various tenants.

In terms of square feet per employee, please note that the Energy+, Enersource, and Powerstream projects are not comparable. For these facilities, the full LDC staff (which is shown in the "FTE" row) is not located at the facility being considered for benchmarking. The average space per FTE for the remaining comparators is 1,121 square feet per FTE, which is just over BPI's square feet per FTE.

ICM Table 13: BPI Compared to Admin and Operations Average			
Statistic	**Average for Administration & Operations Projects**	**BPI Comparison to Average**	**BPI % Comparison to Average**
Gross Square Feet per Employee	1,121	(3.38)	(0.30%)
Capital Cost Per Employee with Inflationary Impact	$ 262,664	($7,796.32)	(2.97%)
Cost per Customer With Inflationary Impact	$ 603	($199.10)	(33.00%)
Capital Cost Per Gross Square Foot with	$ 250	($21.71)	(8.69%)

Comparison with Garden Avenue

Cost Comparison- Overall Cost and Cost per Square Foot

Compared to BP's "Plan B" at Garden Avenue, the overall proposed capital cost at Savannah Oaks is $4.4M lower, or more than 20% less. This is due in part to the purchase price for the existing facility at Savannah Oaks, as well as the limited requirements for new construction and a creative use of the purchased facility which allows for cost sharing for the new facility.

The nature of the purchased space, which was custom-built by the previous owner, includes unique features which do not meet the typical requirements of buyers looking for office space or industrial office space. This and other factors allowed the facility to remain on the market for some time. BPI believes that the unique features at Savannah Oaks allowed it to purchase the facility at a relatively inexpensive price. BPI's creative use of the facility has resulted in further decreases to the cost to be proposed as capital additions. By making adjustments for 13.9 acres of severable land, and by configuring the facility for shared use with multiple tenants, BPI has made further adjustments which allow for this decrease in overall incremental capital costs proposed for inclusion in its Incremental Capital claim.

Drivers of Increased Square Footage

The square footage has increased compared to the Garden Avenue design, due to a number of factors. With respect to the office space, BPI's design at Garden Avenue focused on a compact new-build with relatively small offices. This design aimed to minimize space per FTE to basic standards. By minimizing the office space, BPI was able to reduce cost in the custom build scenario. Additionally, with a custom build at Garden Avenue, BPI's design was able to right-size the office space to accommodate its own staff and its tenants, with some room for increased headcount.

At Savannah Oaks, BPI faces more limitations in the office space configuration. The facility purchase included the existing furniture, which is of good quality and is in good repair. BPI plans to use the existing furniture and configuration in order to avoid additional costs.

The design selected by BPI makes optimal use of the existing office space by making the full first floor available for lease to a tenant or tenants. BPI has also configured the second floor to accommodate its own administrative needs, as well as those of its affiliates and Energy+. As a result of these configurations choices, isolating as much space as possible for tenant use, BPI believes it has made optimal use of the existing office space and minimized the space to be included in capital additions.

The Operations areas have also increased compared to the Garden Avenue design. Once again, the Garden Avenue design focused on minimizing building space in order to minimize cost. At Savannah Oaks, BPI's original intention was to use the Technical Demonstration Centre ("TDC") space as vehicle storage and a warehouse. Upon further technical review, it became apparent that the structure of the space would not be easily configured to allow for vehicle traffic. Specifically, several load-bearing beams within the space would impede vehicle traffic flow and would prevent safe and efficient operations. It was determined that the optimal solution would be to construct new garages for each of BPI and Energy+, and to use the space in the TDC for warehouse, operations space, and the mechanic's bay.

ICM-2.5 Customer Consultation

BPI has always understood that providing value for money is an important priority for customers. This is a priority acknowledged by the OEB, and BPI has taken steps to consider this priority for its facility relocation project. The comprehensive search for a new facility considered many forms of relocation, and expected project cost was always a key consideration.

BPI sought additional feedback on its facility relocation plan in two different customer consultations. The processes and the feedback gained are summarized below, as well as how the feedback is reflected in BPI's planning.

Consultation in 2016

In preparation for its 2017 COS Application, BPI undertook customer consultation activities in early 2016 to determine its customers' opinions on its proposals. One of the proposals that was tested with customers was the Facility relocation plan. The customer engagement was based on a workbook which was used to conduct three survey stages- focus groups, an online workbook, and a randomized telephone survey.

The key outcomes from the consultation held indicated the following, with respect to the facility relocation project:

- Presented with 4 choices (including "something else"), most customers preferred BPI purchase and refurbish an existing facility, followed by building a new facility, then renting/leasing, then "something else".
- Verbatim responses indicated the following preferences regarding BPI's facility planning process:
    - Work with qualified third parties who could advise BPI on its plans;
    - Have business plans, complete due diligence and cost-benefit analysis and consider as many options as possible;
    - Ensure the facility is well-suited to BPI's needs (from customers who preferred a new-build option);
    - Ensure the chosen solution is viable in the long term (ie: don't come back in 10 years with another request for a new facility);
- Most customers (65%+) provided social permission for BPI to implement its plans, including the facility relocation plan. Social permission indicates that customers at least understood the need for the proposed increases despite not "liking" them, with some respondents indicating the support the proposals and the increases.

Consultation in 2018

In 2018, BPI undertook a follow up consultation which built on the 2016 work. The scope of this customer engagement was limited to focus groups. BPI and its consultant worked to update the work book and consult with customers with a focus on its updated facility planning.

Presented with an explanation of BPI's requirements for moving, 50% of participants responded that they rated BPI's need to move as "very urgent", with an additional 38.5% responding "somewhat urgent". 92 % of participants indicated that BPI's relocation plan sounds reasonable. 71% of participants supported BPI's plan to co-locate with other tenants. Most customers believed that service levels would improve as a result of the new shared facility. Ultimately, 71% of participants responded that they either supported the facility plan and its associated rate impact or did not like the increase but thought it was necessary. Through verbatim answers, many participants that believed the rate increase was unreasonable indicated that costs for the facility should not be funded through electricity rates.

Please note, the Workbook presented to customers included the Garden Avenue location as the proposed solution for BPI's relocation. This project was associated with a $19M capital cost to BPI ratepayers, with an associated bill impact range of $2.06 to $2.57 per month for residential customer's and $4.84 to $6.05 for small business customers. Despite this, most components of the consultation are still applicable to the current planned outcome, as customers were surveyed on their agreement that BPI needs to move and on their opinion regarding sharing a building in order to pursue cost savings and service efficiencies.

As the current capital cost and rate impacts for the Savannah Oaks location are expected to be **below** the levels presented to customers in 2018, BPI believes it is reasonable to assume the same level of support for the project would have been obtained if the Savannah Oaks location would have been presented.
The 2018 and 2016 Consultation reports are included together as ICM Appendix E.

Application of Feedback Received from Customers

The feedback received from customers both in the 2016 and 2018 consultation processes is in line with the process planned by BPI. BPI has worked with qualified consultants, retained through competitive and open processes throughout its planning. BPI considered the suitable options available against criteria which were directly linked to either service provision or cost impact. Additionally, having secured an option which met both the operating requirement and cost criteria, BPI has undertaken various initiatives to reduce the impact of its facility relocation on customers. Specifically:

- The severance of excess land included with the property;
- The recruitment of partner companies for the sharing of the existing facility space;
- The isolation of the space on the first floor to be rented to a third party (and the consolidation of BPI operations on the second floor to minimize costs attributable to ratepayers); and

- The partnership with Energy+ in the pursuit of both facility cost sharing and further operating efficiencies through shared services.

ICM-2.7 Description of Facility and Location

The new facility will be a consolidated location with space for BPI, Energy+, its affiliates and a third tenant (or tenants) which is still to be determined. The purchased facility includes a component of developable land, a parking lot, a two-story main building with offices space, and a building with mainly industrial usage which is connected to the main office building.

Land

The property at 150 Savannah Oaks has several elements. The total land included with the purchase is 46.4 Acres, and includes and already severed component to the West of the facility which is severed and is officially named separately as 29 Tallgrass Court. The existing property also includes undeveloped land to the East of the building, much of which (13.5 acres) is taken up by a large pond and the surrounding banks of this pond.

In consultation with its project manager, BPI has identified 13.9 acres (including the majority of the already severed Tallgrass Court component) which are likely severable, and which will not be required by BPI. BPI intends to sell these parcels of land, and has therefore excluded their value from Rate Base. In order to determine the most appropriate value for these parcels of land, BPI consulted with its Audit Firm, KPMG LLP, which in turn recommended allocating the purchase price of the total property among several components of the property in order to determine the value of the saleable land to be excluded from its incremental capital claim and eventually from Rate Base. KPMG recommended this valuation can be completed by a qualified third party evaluator. BPI retained Jacob Ellens & Associates for this purpose. As a result of the Jacob Ellens appraisal, BPI estimates the portions of land to be severed and sold is $3.125M.The Jacob Ellens appraisal is included as ICM Appendix C

Building

The existing building has two main components, a two-story office building and a “Technical Demonstration Centre” (TDC) which is an industrial space connected to the office building via a link in the second floor. The table below summarizes the major special components of the facility.

ICM Table 14: Summary of Indoor Space	
Area	**square feet**
Ground Floor	36,640
Second Floor	33,914
Total Office Building Space	**70,554**
Main Floor	26,818
Mezzanine	7,664
Total Technical Design Centre	**34,482**
BPI New Garage	16,243
Energy+ New Garage	10,260
Total New Garages	**26,503**
Total Indoor Space	**131,539**

A draft floor plan with the corresponding square footage values is included as ICM Appendix D.

Office and Admin Space

The main portion of the building includes two floors totaling 70,554 square feet of office and administrative space, with offices, cubicles, meeting rooms and other facilities. BPI, in consultation with its Project Manager and AECOM, has determined that the second floor is best suited to meet the needs of BPI, its affiliates and Energy+, leaving the Ground floor available for another party which is yet to be recruited ("Tenant 3"). This arrangement was determined to be ideal based on the following rationale:

- The ground floor was leased to a tenant by the previous owner and as a result, there were already adequate measures in place to isolate the tenant space such as separations and separate entrances;
- The linkage to the TDC area is from the second floor, so maintaining access to this section for BPI and Energy+ was a key advantage;
- The office space was large enough to accommodate all of Energy+, BPI and the affiliate office space requirements;
- The arrangement allowed BPI to keep its departments in close proximity of one another, while remaining as close as possible to the warehouse/TDC; and
- The arrangement also optimizes the availability of accessible routes to all tenants.

The allocation of the space is summarized below:

ICM Table 15: Summary of Indoor Space		
Area	**Square Feet**	**Description**
Ground Floor		
Tenant Space	25,718	First Floor offices and cubicles, tenant reception, meeting rooms, washrooms
Common Space	10,922	Reception Area, Cafeteria, Mail Room, Washrooms, Stairwells, Side Entrance and Stairwell
Second Floor		
BPI Space	24,799	Offices, Cubicles, Meeting Rooms, Storage, Washrooms, Board Room, Coffee area, Copy Area
Common Space	5,035	Storage, Washrooms, Staircases, Common Storage
Affiliate Space	3,154	Server Room, Offices , Cubicles
Energy+ Space	926	Offices, Meeitng Rooms
Operations Centre		
Energy+ Exclusive Space	13,303	Garage, Operations Space
BPI Exclusive Space	27,050	Garage, Operations Space, Mezzanine
Shared Space	20,632	Warehouse, Repair Garage
TOTAL	**131,539**	

Operations Space

Warehouse

The warehouse will include the indoor inventory storage of BPI and Energy+. There will be separate, isolated areas for the equipment of each party initially; however some aspects of inventory management will be shared between the two LDCs. In the future, BPI and Energy+ plan to investigate further opportunities for the sharing of inventory services, including the potential harmonization of some inventory.

Garages

Due to the existing column spacing in the Technical Demonstration Centre (TDC) area, circulation of larger vehicles will be restricted. While this was considered feasible in the 2015 review of the property, further assessment has determined that it is not operationally efficient. New separate, secure vehicle storage garages are proposed for BPI and Energy+ as indicated on the concept drawings. The TDC area would be used for the shared Warehouse shared Repair Garage, Energy+ Operations staff and BPI Operations staff.

Repair Garage

The TDC will include a repair garage with two vehicle bays. A mechanic will perform repairs and maintenance for BPI and Energy+ vehicles. Previously, BPI outsourced mechanical services. The shared mechanic's bay with Energy+ is expected to result in efficiencies and/or service improvements.

Outside Space

Parking Lot and Yard

5.4 Acres of exterior storage are required for items typically stored outside (poles, transformer vaults,etc.) for both BPI and Energy+. The yard requires a component of the Tallgrass Court property. The Savannah Oaks property is subject to a zoning bylaw which would prevent BPI from using the facility for outdoor storage. BPI is currently in the process of applying for a bylaw amendment which would allow the storage of certain types of equipment outdoors. If this is not approved, BPI may be required to increase its facility budget to make other storage arrangements for large items.

The parking lot includes 252 parking spaces, which is sufficient for BPI and its three confirmed tenants. The parking lot has multiple entrances/exits which should allow for efficient circulation of operations trucks as well as staff and visitor vehicles.

ICM-2.8 Project Budget

The project budget is summarized below.

ICM Table 16: Summary Total Project Budget (all tenants)		
	Projected Cost - Total Building	
Construction, Soft Costs, Permits and Fees	$	19,714,948
Land and Building	$	8,670,102
Building Capital Cost	**$**	**28,385,050**
Furniture, Fixtures and Equipment	$	551,000
Total Proposed Budget	**$**	**28,936,050**

The land component of the budget has been reduced for the value of the severable land, as calculated below. The $19.7M construction element includes the following:

- The cost to construct the new garages and associated linkages;
- The cost to refurbish the TDC, creating the new warehouse and repair garage, as well as BPI and Energy+ Operations areas including locker rooms, washrooms, etc.
- The cost of refurbishing the office space and add enclosures to ensure the separation of tenants and meet requirements for accessibility ;

- Preparation, fencing and security for the yard and construction of a fueling station;
- Escalation and contingency provisions;
- Permits and fees for the purchase of the facility and the approval of the new construction;
- Capitalized borrowing costs while the project is in progress;
- Internal capitalized labour directly attributable to bringing the facility asset to its intended use;
- Soft costs such as project management, cost consulting, due diligence and legal fees; and
- A portion of costs from the Garden Avenue project which are related to transferrable work including detailed specifications and designs.

The Furniture, Fixtures and Equipment budget is primarily related to warehouse and mechanic's bay equipment, as well as some limited budgets for office furniture and appliances.

Reduction for Severable Land

The full purchase price for the facility was $11,550,000. Included in this purchase price were the building and land, including the pond, some empty, severable land south of the pond, and the already severed piece of land "29 Tallgrass Court". BPI intends to sell a portion of the land, and has made a reduction to the purchase price for the value of the land to be severed.

To determine an appropriate value for the severable land, BPI first consulted KPMG to establish the best method to achieve this. KPMG counseled BPI to have a third party valuation of the market value of the existing land and building, and to allocate the purchase price proportionally among the components.

BPI retained Jacob Ellens and Associates to complete the valuation, which is summarized below and included as ICM Appendix C. Please note, as the property 29 Tallgrass Court is already severed, that component of the overall purchase was assessed as a whole and assumed to be saleable. BPI intends to use 1.32 Acres of 29 Tallgrass court and as a result has made a proportional adjustment to reflect this. Overall, BPI has reduced the purchase price by $3.1M to account for the 13.9 Acres of saleable land.

ICM Table 17: Adjustment for Severable Land				
Component	**Acreage**	**Assessed Value**	**% of Total Value**	**Allocated Purchase Price**
29 Tallgrass Court	4.8	1,210,000	10%	$ 1,122,530
Additional Excess Land	10.4	2,340,000	19%	$ 2,170,843
Pond and Embankment	13.5	$ -	0%	$ -
Improved Portion- Land	17.7	$ 4,430,000	36%	$ 4,109,759
Improved Portion-Building		$ 4,470,000	36%	$ 4,146,867
Total	46.4	$ 12,450,000	100%	$ 11,550,000
				$ (900,000)
Portion of 29 Tallgrass Court to be Kept for Use (acres)	1.32			
Total Useful Land Above (acres)	32.93	a		
Value of Land Above	$ 7,403,133	b		
Average Value/Acre	$ 224,814.23	c=b/a		
Acres of Saleable Land	13.90	d		
Value of Saleable Land	$ 3,124,917.770	e=d*c		
Value of Remaining Land & Building	$ 8,425,082.23	f=11,550,000-e		

Allocation of Purchase Price

The following tables show the allocation of space among the parties. The allocated existing building cost of 4,146,867 has been allocated proportionally based on square footage to each of the following categories of "occupant":

- BPI;
- Energy+,
- Affiliates;
- Tenant 3;
- Shared (BPI and Energy+); and
- Common Space (Shared among all tenants).

Additionally $4,278,215 in land (useable land of $7,403,133, less severed land of $3,124,918) has been allocated based on proportional share of building and yard usage). These allocations are summarized in the table below:

Table ICM 18: Allocation of Purchase Price

Space Description	Occupant	Square Feet	% of Total Existing	% of Land	Cost Allocations - Land	Cost Allocations - Building	Total Cost
Vehicle Storage Garage	BPI	-	0.0%	0.0%	-	-	-
Ops Office	BPI	3,143	3.0%	2.4%	103,469	124,087	227,556
Office	BPI	32,463	30.9%	25.0%	1,068,695	1,281,654	2,350,349
		35,606	34%	27%	1,172,164	1,405,741	2,577,904
Office	E+	926	0.9%	0.7%	30,484	36,559	67,043
Ops Office	E+	3,043	2.9%	2.3%	100,177	120,139	220,316
Vehicle Storage Garage	E+	-	0.0%	0.0%	-	-	-
		3,969	4%	3%	130,661	156,698	287,359
Warehouse	Shared - E+/BPI	18,404	17.5%	14.2%	605,867	726,598	1,332,465
Repair Garage	Shared - E+/BPI	2,228	2.1%	1.7%	73,347	87,962	161,309
Outdoor yard	Shared - E+/BPI		0.0%	19.2%	820,387	-	820,387
		20,632	20%	35%	1,499,601	814,560	2,314,161
Common Area - 2nd Floor	Shared - All	5,035	4.8%	3.9%	165,754	198,784	364,538
Common Area - Ground Floo	Shared - All	10,922	10.4%	8.4%	359,557	431,205	790,762
		15,957	15%	12%	525,311	629,989	1,155,300
Office	Affiliates	3,154	3.0%	2.4%	103,831	124,521	228,352
IT Space	Affiliates		0.0%	0.0%	-	-	-
		3,154	3%	2%	103,831	124,521	228,352
Office	Tenant 3	25,718	24.5%	19.8%	846,647	1,015,358	1,862,005
Common Space	Tenant 3	-	0.0%	0.0%	-	-	-
		25,718	24%	20%	846,647	1,015,358	1,862,005
TOTAL - EXISTING BUILDING		**105,036**	**100%**	**100.0%**	**4,278,215**	**4,146,867**	**8,425,082**

Construction and Refurbishment Budget

The space requirements for the new Garages for BPI and Energy+ are summarized below:

Table ICM 19: New Construction			
Vehicle Storage Garage	BPI	16,243	61%
Vehicle Storage Garage	E+	10,260	39%
TOTAL - ADDITIONS		**26,503**	**100%**

BPI has allocated the additional budgeted amounts (beyond the original purchase price) below.

ICM Table 20: Allocation of Non-Purchase Budget

Occupant	Exclusive	%	% of Space Occupied	ALL	BPI	E+	Shared (BPI/E+)	TOTAL
				Other Capital Costs to be Allocated				
BPI	51,849	39.4%	53.78%	$ 2,051,624	$ 5,915,144	$ -	$ -	$ 7,966,769
E+	14,229	10.8%	21.24%	$ 563,030	$ -	$ 3,545,472	$ -	$ 4,108,503
Affiliates	3,154	2.4%	2.73%	$ 124,801	$ -	$ -	$ -	$ 124,801
Shared - E+/BPI	20,632	15.7%		$ 816,392	$ -	$ -	$ 5,294,456	$ 6,110,848
Shared - All	15,957	12.1%		$ 631,406	$ -	$ -	$ -	$ 631,406
Tenant 3	25,718	19.6%	22.25%	$ 1,017,641	$ -	$ -	$ -	$ 1,017,641
Totals	131,539	100.0%	100.00%	$ 5,204,895	$ 5,915,144	$ 3,545,472	$ 5,294,456	$ 19,959,968

The costs directly associated with the new construction specific to the BPI, Energy+ and Shared "occupants" were allocated to those parties, while the remaining $5,204,895 (comprised of costs such as project management, capitalized interest, Permits and Fees) was allocated based on relative proportions of the 131,539 square feet (ie: 39.4% or $2,051,624 was allocated to BPI, etc).

The project cost allocations (excluding FF&E) among the occupant categories are summarized below and include both the net purchase price allocations and the new construction allocations.

ICM Table 21: Total Budget Allocation (excl FF&E)

	Initial Purchase Price	Allocated Costs	Total
BPI	$ 2,577,904	$ 7,966,769	$ 10,544,673
E+	$ 287,359	$ 4,108,503	$ 4,395,862
Affiliates	$ 228,352	$ 124,801	$ 353,154
Shared - E+/BPI	$ 2,314,161	$ 6,110,848	$ 8,425,010
Shared - All	$ 1,155,300	$ 631,406	$ 1,786,706
Tenant 3	$ 1,862,005	$ 1,017,641	$ 2,879,646
Totals	$ 8,425,082	$ 19,959,968	$ 28,385,050

In order to achieve "fully-allocated" costing for each party, the Shared –All category has been re-allocated among each tenant (BPI, Energy+, affiliate and Tenant 3) on the basis of their relative % of occupied space (from table 20 above) .

For example, BPI was allocated 53.78% of the "shared- All" cost of $1,786,706 (from ICM Table 21 above), representing $960,968. The Shared E+/BPI category totaling $8,425,010 was allocated on a 50% basis between BPI and Energy+, representing an additional $4,212,505 allocated to BPI. BPI's "fully allocated" capital cost was then $15,718,146 (direct allocation of $10,544,673 plus $960,968 from "shared- all" and $4,212,505 from "Shared- E+/BPI"). These fully allocated costs and square footages are summarized in the table below.

Please note the cost allocated to BPI is before FF&E additions.

ICM Table 22: Fully Allocated Costs and Square Footages				
	Initial Purchase Price	Allocated Costs	Total	Sq Feet
BPI	$ 4,356,356	$ 11,361,790	$ 15,718,146	70,747
E+	$ 1,689,779	$ 7,298,012	$ 8,987,792	27,934
Affiliates	$ 259,878	$ 142,031	$ 401,909	3,589
Tenant 3	$ 2,119,069	$ 1,158,134	$ 3,277,204	29,269
Totals	$ 8,425,082	$ 19,959,968	$ 28,385,050	131,539

Level of Certainty

As the construction components of the facility relocation 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. The table below shows how much of the total project budget is associated with the Class D level of certainty.

ICM Table 23: Budget Certainty			
Budget Estimate Level	Budget Amount	% of Budget excluding	Items included
Costs Already Incurred	$ 12,538,420	44%	Land, Building, reduction for Land to be severed, Transferred Design Costs
Expected Sale of Land	$ (3,124,918)	-11%	
Class D	$ 18,971,548	67%	Construction Cost ,Soft Costs, FF&E, Permits and Fees, Internal Labour, Capitalized Construction Interest.
Total Project	$ 28,385,050	100%	

ICM-2.10 Project Timelines

BPI intends to move its operations to 150 Savannah Oaks in early 2020, following renovations and refurbishments to the inside office space. The facility is already in use regularly, with leadership operating from this facility roughly 20% of the time. BPI staff regularly hold meetings at this location, and BPI has held a Board of Directors meeting at Savannah Oaks as well. The inside office space is generally ready to be occupied at this time and requires minor, cosmetic adjustments to meet BPI's requirements and to isolate the spaces to be used by other occupants as needed. Additional equipment, vehicles, and the full operations will be gradually moved to 150 Savannah Oaks before the end of 2020, as the yard, warehouses and vehicle garages are completed and ready for occupancy.

A timeline prepared by BPI's Project Manager is included as ICM Appendix F.

ICM Appendix A:

2017 COS Settlement Excerpt

BPI confirms that the resources available to BPI in the Test Year under the terms of this Settlement Proposal, provide a foundation for BPI to continue to:

- pursue continuous improvement in productivity;
- maintain system reliability and service quality objectives; and
- maintain reliable and safe operation of its distribution system.

In conjunction with its responses to interrogatories, BPI withdrew its request for approval of the cost consequences of a proposed facility relocation for the Test Year (see responses to IR 2-Staff-7, IR 1-Staff-1).

To ensure that in the event BPI makes an application for an for an Incremental Capital Module ("ICM") prior to its next Cost of Service rebasing or Custom IR application, ratepayers are held whole from any underspending compared to the level of in-service additions built into the Test Year rates, the Parties agree that the ICM threshold as calculated at that time will be increased by an amount equal to any difference between planned and actual aggregate in-service additions in 2016 and 2017.

The calculation of this difference will be asymmetrical, with no adjustment if BPI spends <u>more</u> than its approved in-service additions for either year. The underspending on the total in-service additions, if any, for each year will be added together. For 2016, the underspent in-service additions will contribute on a 1-to-1 basis to the amount added to the ICM threshold. For 2017, to acknowledge the impact of the half-year rule for Test Year in-service additions, the underspent capital will contribute on a 50% basis.

Attachment C of this Settlement Proposal includes an updated Ch2. Appendix 2-AA and 2-AB to reflect this settlement.

The capital spending forecast over the future period is presented in Appendix 2-AA and 2-AB. Appendix 2-AB will represent the basis for BPI's calculation of its performance for Distribution System Plan implementation for its annual scorecard, as proposed in its DSP, and until the OEB releases a standard measure to be implemented by all electricity distributors.

SUPPORTING PARTIES:
All

ICM Appendix B:

Letter from City of Brantford on Lease Expiry

January 11, 2018

Mr. Paul Kwasnik
CEO & President, Brantford Power Inc.
84 Market Street
Brantford, ON
N3T 5N8

Re: Brantford Power – Rental of Space

Dear Mr. Kwasnik,

Further to the City's letter dated May 22, 2015, the Corporation of the City of Brantford is in the process of implementing a Corporate Facilities Accommodation Strategy. Further, staff is in the process of updating the 2014 Services Works Yard Facilities Rationalization Study. These two initiatives will affect the space that the Brantford Power Inc. ("BPI") currently utilizes within City facilities.

The intention of these initiatives is on consolidating and optimizing facilities that house City Administrative staff, operational facilities and works yards in order to support an efficient and cost-effective delivery of municipal services through fewer and more centralized points-of-contact. In 2017, City Council authorized the procurement of a new administrative facility which will be renovated in 2018/2019. This new facility will see the relocation of all City staff from 84 Market to a new location (70 Dalhousie). BPI currently leases 8,617 sq. ft. in this building. While a long term decision has not been made with respect to the future of 84 Market, it will likely be deemed to be a property for Council to consider divesting of.

Further, you will recall that 220 Colborne Street where BPI currently leases 2,839 sq. ft. of commercial office space was sold by the City of Brantford to Laurier University. As such, the City is required to vacate City and leased space by June 2022.

With respect to 400 Grand River Avenue, BPI currently leases 8,178 sq. ft. commercial office and warehouse space, 11,288 sq. ft. vehicle storage space and 112,000 sq. ft. outside storage space, the Yards Master Plan indicated there is a requirement for the space to accommodate City works yards functions. We have already seen pressure as Transit services has expanded and the addition of Metrolinx's GO Transit indoor vehicle storage requirements have placed additional demands on space.

The intent of this letter is to convey to BPI that the Accommodation Strategy has been finalized and implementation is underway. The strategy and timing of the City's use of the BPI space has been based upon BPI vacating the building in or before 2019. Additionally this letter serves as formal notice that the City will not be renewing existing leases.

Should you have any inquiries, please do not hesitate to contact me or Geoff Linschoten, Director of Facilities and Asset Management.

Regards,

E. (Beth) Goodger
General Manager, Public Works Commission

Copies:

D. Lee, CAO, City of Brantford
G. Linschoten, Director, Facilities and Asset Management

ICM Appendix C:

Appraisal of 150 Savannah Oaks Property;

JACOB ELLENS & ASSOCIATES INC.
REAL ESTATE APPRAISERS & CONSULTANTS

August 9, 2019

Brantford Power Inc.
Box 308
Brantford, ON N3T 5N8
Phone: (519) 751-3522

Attention: Mr. Brian D'Amboise,
CFO & VP Corporate Services

Dear Mr. D'Amboise:

RE: Additional Commentary and Breakdown of Value with regards to the Appraisal of 150 Savannah Oaks Drive & 29 Tallgrass Court, Brantford
Our File No. 19-8896V(L)

As per your request, I have provided a breakdown of values as they relate to the improvements and underlying land value.

Within the market value opinion provided in the appraisal report with an effective date of May 7, 2019, the value for 29 Tallgrass Court was $1,210,000. The value for 150 Savannah Oaks Drive was $11,240,000. The pond area is calculated at 13.5 acres. The appraiser considers this land to have nominal value and does not contribute overall to the project.

Of that amount, the underlying land value for the improved portion was calculated, when rounded, to $6,770,000, resulting in the residual value for the improvements being $4,470,000. The land to building ratio is at 64% to 36%.

29 Tallgrass Court:	**$1,210,000**
Excess Land:	**$2,340,000**
Improved Portion:	**$8,900,000**
Total Market Value:	**$12,450,000**

The appraiser believes this is an accurate representation of the breakdown in values when considering those presented in the appraisal report.

/…2

This letter should be read in conjunction with the information provided in our market value opinion. Should the client request any additional information, we would be pleased to furnish it upon request.

Respectfully submitted,

JACOB ELLENS & ASSOCIATES INC.

Matt Van Huizen, B.A., AACI, P.App.

ICM Appendix D:

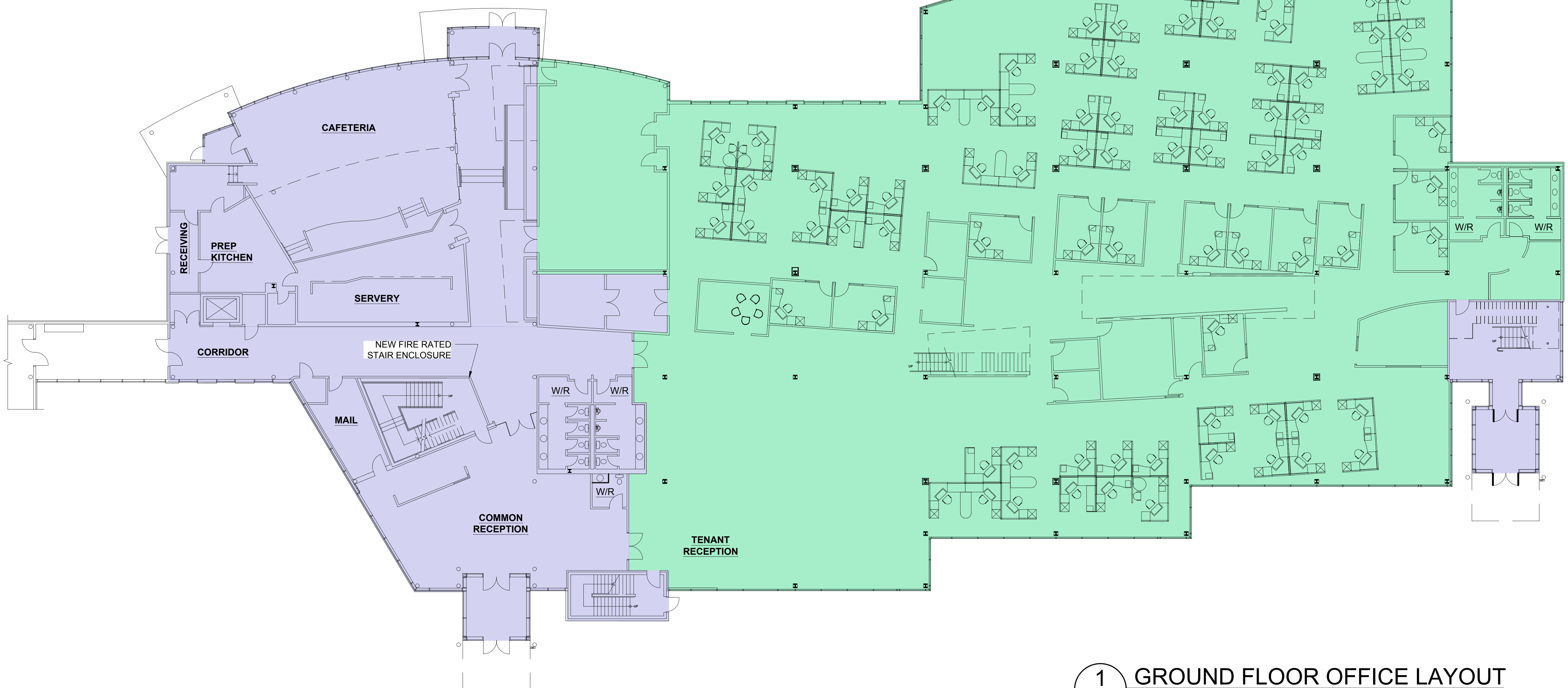
Draft Floor Plans

AREA LEGEND

BPI SPACE = 0 SQ.FT. (0 SQ.M.)

COMMON SPACE = 10,195 SQ.FT. (947 SQ.M.)

TENANT SPACE = 25,718 SQ.FT. (2,389 SQ.M.)



1 GROUND FLOOR OFFICE LAYOUT

DD-2 SCALE: 1:300 TOTAL AREA: 36,364 SQ.FT. (3,378 SQ.M.)

AECOM

AECOM Canada Architects Ltd.

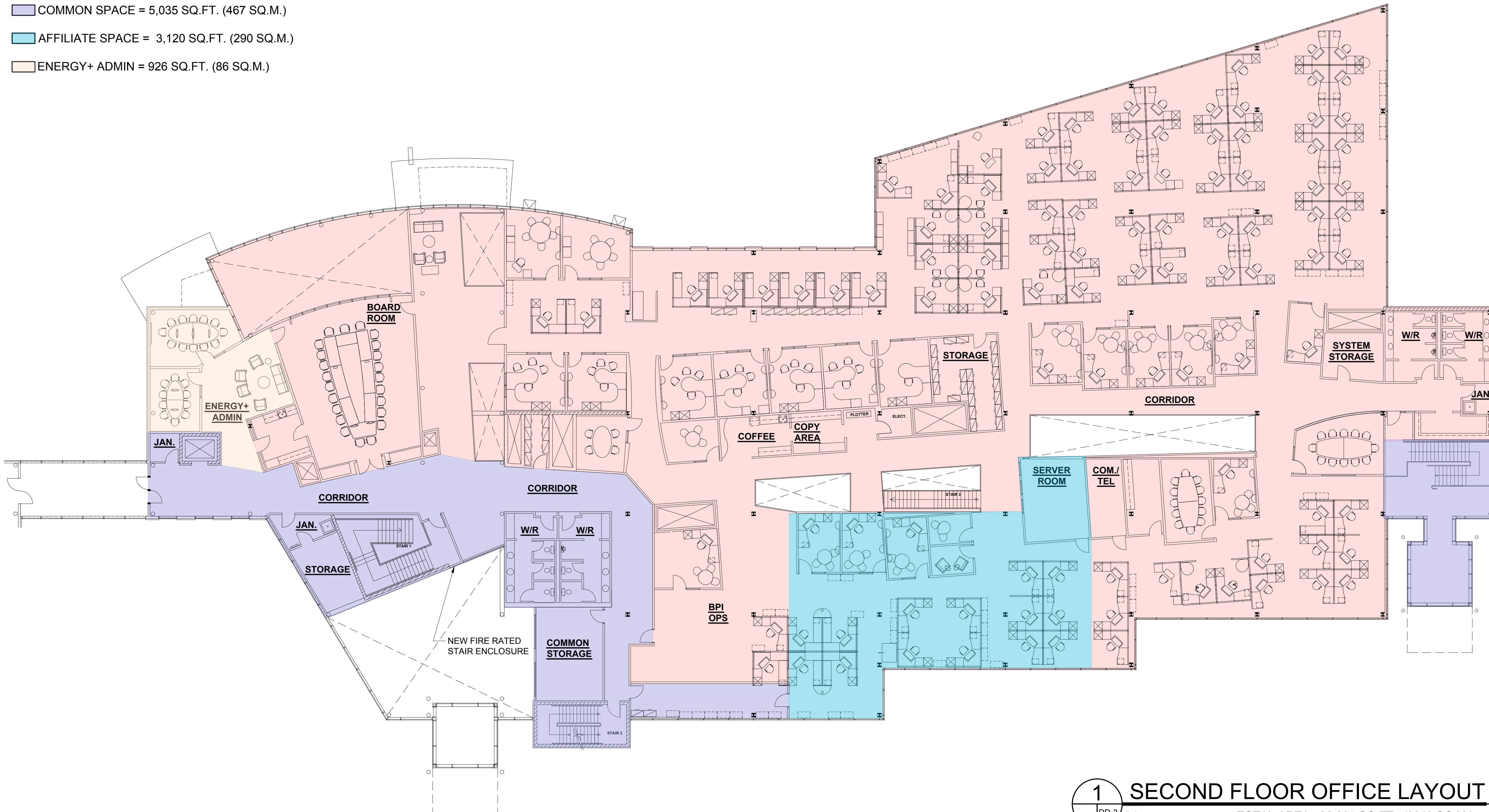
Brantford Power Operation Centre Study - 150 Savannah Oaks Drive

GROUND FLOOR OFFICE LAYOUT

BRANTFORD power Your delivery company

AREA LEGEND

- BPI SPACE = 24,808 SQ.FT. (2,304 SQ.M.)
- COMMON SPACE = 5,035 SQ.FT. (467 SQ.M.)
- AFFILIATE SPACE = 3,120 SQ.FT. (290 SQ.M.)
- ENERGY+ ADMIN = 926 SQ.FT. (86 SQ.M.)



1 DD-3 SECOND FLOOR OFFICE LAYOUT

SCALE: 1:300 TOTAL AREA: 32,385 SQ.FT. (3010 SQ.M.)

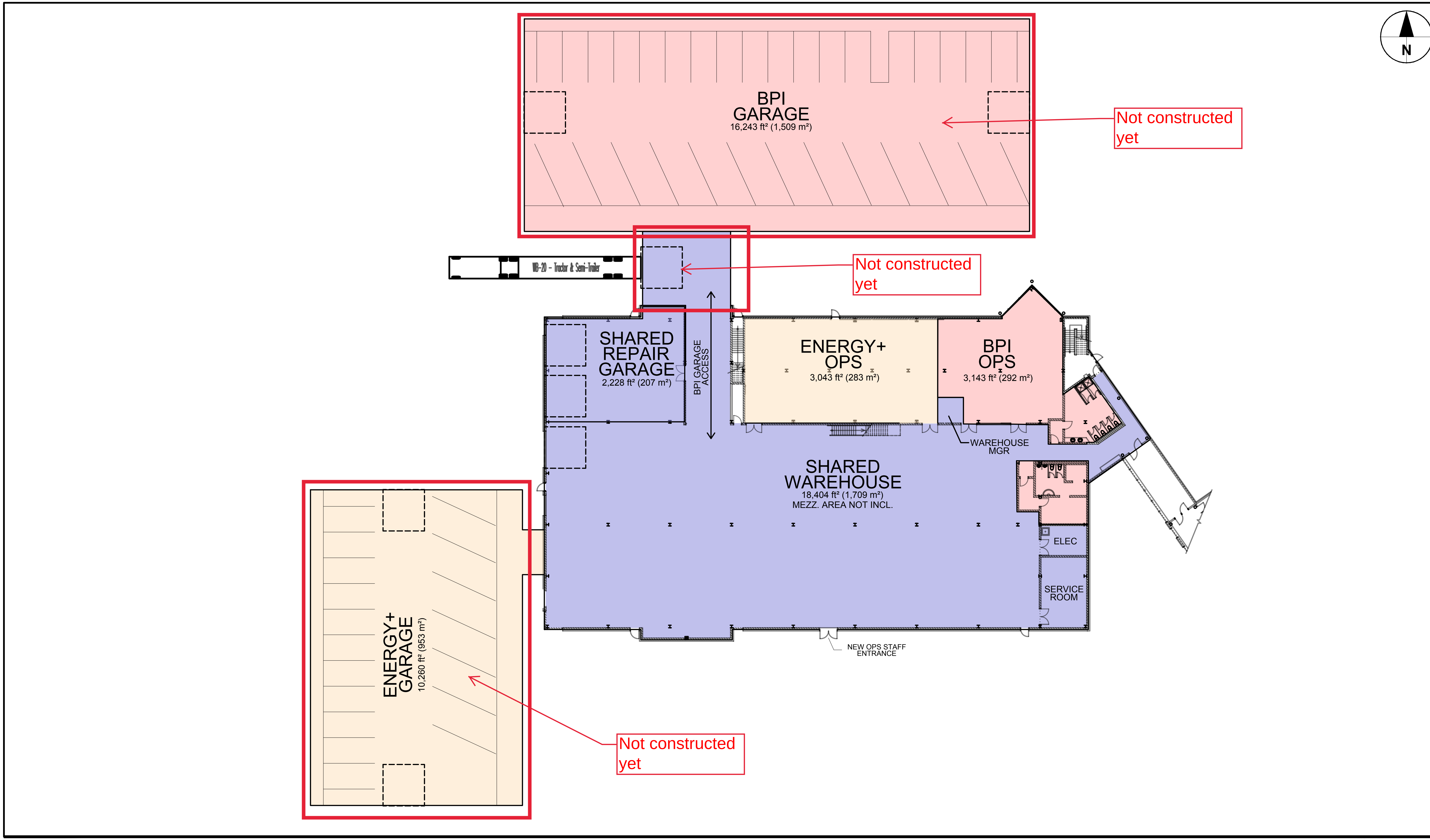
AECOM

AECOM Canada Architects Ltd.

Brantford Power Operation Centre Study - 150 Savannah Oaks Drive

SECOND FLOOR OFFICE LAYOUT

BRANTFORD power Your delivery company



AECOM Canada Architects Ltd.

Brantford Power Operation Centre Study - 150 Savannah Oaks Drive

ICM Appendix E:

Consultation Materials

CUSTOMER ENGAGEMENT

2020 ICM Application

Report

August 7, 2018

Prepared for:

Brantford Power Inc.

220 Colborne St Box 308

Brantford, ON N3T 5N8

Customer Engagement: 2020 ICM Application

August 2018

Confidentiality

This Report and all of the information and data contained within it may not be released, shared or otherwise disclosed to any other party, without the prior, written consent of Brantford Power Inc. (BPI).

Acknowledgement

This report has been prepared by Innovative Research Group Inc. (INNOVATIVE) for BPI. The conclusions drawn and opinions expressed are those of the authors.

Jason Lockhart
Vice President
Innovative Research Group Inc.
56 The Esplanade, Suite 310, Toronto ON | M5E 1A7
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Email: jlockhart@innovativeresearch.ca
www.innovativeresearch.ca

Table of Contents

1. Executive Summary

1.1 Context

Innovative Research Group (**INNOVATIVE**) was engaged by Brantford Power Inc. (**BPI**) to assist the utility in meeting its customer engagement commitments under the Renewed Regulatory Framework for Electricity Distributors.

BPI has a capital investment requirement for 2020 that is not funded through existing distribution rates. This unfunded capital requirement has arisen from BPI's need to find new facility space to house its staff, vehicles and equipment. By 2022, BPI will be moving from its three existing leased facilities, with no available options to extend its occupancy.

After conducting a comprehensive facility relocation due diligence exercise, beginning in 2014 – which considered *cost to customers*, *customer service delivery, availability of local inventory*, *impact on efficiency*, and *future growth considerations* –BPI management is of the opinion that some form of facility ownership is in the best interest of the utility and its customers.

To meet this capital investment need, BPI will submit an Incremental Capital Module (ICM) application to the Ontario Energy Board (OEB) in 2019 for January 1, 2020 rates. The outcome of this application will impact BPI's customer distribution rates and set the pace of the utility's capital investment plan for 2020 and beyond.

While there is no explicit OEB requirement for distributors to engage its customers for input on ICM applications, in the *customer-centric* spirit of the RRFE, BPI felt it prudent to consult its customers on its proposed facility relocation plan, given the material impact this capital investment will have on distribution rates.

Presently, BPI engages customers through a wide variety of ongoing customer touchpoints and research activities that help inform customer service offerings, operating budgets, and capital plans. INNOVATIVE has been asked to supplement BPI's existing efforts with activities focused on bringing customer needs and preferences – regarding outcomes and trade-offs – into BPI's 2020 ICM application planning process.

In approaching the design of this consultation, INNOVATIVE considered input collected in 2016 through previous customer engagement activities used to inform BPI's 2017 Cost of Service (COS) rate application. This previous customer engagement included an online feedback portal and randomly recruited focus groups, leading up to random digit dialing customer telephone surveys.

While this earlier COS engagement provided a comprehensive understanding of customer preferences towards BPI's original facility relocation plan, the revised facility relocation plan, being considered in 2018, required a new customer engagement.

To assist BPI with the development of its 2020 ICM application, INNOVATIVE conducted a series of focus groups with small business and residential customers. The purpose of these focus groups was to collect customer feedback on BPI's proposed facility relocation plan and inform the direction of its 2020 ICM application.

This report details the qualitative findings from BPI customer focus groups, conducted in July 2018.

Note: Qualitative research does not hold the statistical reliability or representativeness of quantitative research. It is an exploratory research technique that should be used for strategic direction only.

Interpreting focus groups findings: In qualitative focus group research, the value of the findings lies in the *depth* and *range* of information provided by the participants, rather than in the *number* of individuals holding each view. References in this report such as "most" or "some" participants cannot be projected to the full population. Only quantitative research, with larger samples, would be accurately projectable to the full BPI customer base.

1.2 Key Findings

Familiarity with Electricity System

As observed in similar customer consultations across the province, many customers are not familiar with distributors' role in the electricity system, the information contained on their bills, or how rates are set in Ontario.

Satisfaction and Areas for Improvement

Overall, most customers are very satisfied with the services they receive from BPI. That said, when asked what BPI could do to improve its existing services, a number of areas were identified:

Power quality and reliability was identified as a key area for improvement among customers who report experiencing above average number of service interruptions and businesses that have experienced power quality issues.

While most customers recognize that no distribution system can deliver 100% reliable power all the time, they do expect better service in term of **outage communications** when experiencing a service interruption.

- This is particularly important for small businesses who need this information to better manage shifts and labour. For example, one business owner asked, "*Do I send my staff home and close for the day or tell them to hangout in the parking lot for 20 minutes until the power is restored?*"
- Residential customers asked for tools such as text messaging and outage maps (however, when asked if they would be willing pay for these service, responses were mixed).

Cost of electricity was mentioned by a few residential customers but did not come up in the small business groups in terms of things that BPI could do to improve services. That said, most of the residential concerns around cost stemmed from TOU pricing.

Feedback on the Proposed Facility Relocation Plan

After providing customers with educational background on BPI, its role in the provincial electricity system, customer bills, and how rates are set in Ontario, details where then shared on BPI's proposed facility relocation plan and 2020 ICM application.

As documented in the workbook, the proposed facility relocation could result in an increase of **$2.06 to $2.57 per month** on the distribution portion of the average residential customer's electricity bill (**$4.84 to $6.05 per month** for the average small business).

As part of BPI's plan, the new facility will be shared with Energy+, NetOptiks and Enersure. Most focus group participants strongly support this idea of a shared facility as a means of offsetting costs to BPI ratepayers.

In terms of explaining the facility relocation plan, all participants felt they understood the reasons for BPI's relocation after reading the information provided in the workbook. Furthermore, a majority of participants also believe the need to relocate is "very urgent". When asked how they thought a new facility would impact customer service, a majority thought the new building will result in "better customer service".

Everything considered, most participants felt BPI had conducted a thorough due diligence and planning exercise when it come of the facility relocation.

Social Permission on Proposed Plan

Note: In the context of this report, "social permission" is defined as those customers who either believe *the proposed rate increase is reasonable and [they] support it* or have expressed the view that they *don't like it, but [they] think the proposed rate increase is necessary* given the information presented by BPI.

BPI initially hired INNOVATIVE in 2015 to design and conduct a comprehensive customer engagement program to inform the direction of its 2017 COS rate application. At the time of this previous consultation, the generalizable telephone survey measured *permission to move ahead with owning a shared consolidated facility* – refurbished or new build– at 61% for both small business and residential customers.

While the facility relocation plan has changed since the previous consultation, most customers provide permission to move ahead with a new building. That is, a majority of customers either support the proposed relocation plan or at least think it's necessary.

***Question**: Considering what you know about the plans for Brantford Power's relocation and its impact on your rates, which of the following best represents your point of view?*

Response Code	Small Business	Residential	Total
The proposed rate increase is reasonable and I support it	0	5	5
I don't like it, but I think the proposed rate increase is necessary	7	5	12
The proposed rate increase is unreasonable and I oppose it	4	3	7
Don't know	0	0	0
Total	**11**	**13**	**24**
Social permission to move ahead with proposed plan	**7/11**	**10/13**	**17/24**
Social permission %	**64%**	**77%**	**71%**

Some of the reasons cited by the seven participants who felt the presented plan to be unreasonable are as follows:

- "*Utilities are wasteful and should be able to find efficiencies and cost savings to finance the new build without having to raise rates*."
- "*Customers already pay enough and I would be willing to accept more outages if that meant keeping bills down*." … a number of other customers interjected to say they would not be comfortable with that option.
- "*BPI should find 'creative solutions' to finance the new building in a way that won't impact ratepayers*." When asked to explain what kind of 'creative solutions' the participant had in mind, it was suggested that BPI should:
    - ask the City for an equity investment that would cover the cost of the new building;
    - ask the City to provide an existing facility; or
    - ask the City defer their dividend until the new building is fully paid for.
- *BPI should reduce executive compensation to pay for this new building*.

2. Methodology

INNOVATIVE's objective was to obtain insights into customer expectations and preferences with regards to BPI's proposed facility relocation plan. To better understand customer preferences, a total of four focus groups – consisting of 24 BPI customers – were conducted on Thursday, July 12, 2018 in Brantford (*Best Western Brantford Hotel & Conference Centre*). All focus group sessions were video recorded to verify participant feedback and verbatim quotes.

Low-volume customer focus groups were conducted in segregated sessions by rate class, led by two INNOVATIVE moderators in separate, simultaneous sessions:

- 2 **Small Business** focus groups (5:30PM – 7:30PM) – 11 participants
- 2 **Residential** focus groups (8:00PM – 10:00PM) – 13 participants

Focus Group Recruitment of Low-Volume Customers

1. **Small business** customers were randomly selected and then screened by telephone for appropriateness as focus group participants. Customers qualified for the focus group if they manage or oversee their organization's electricity bill; this ensures that they are at least somewhat knowledgeable of their electricity costs and could have an informed discussion on the impact of the proposed distribution rate increase presented in the ICM application. Following industry standards, small business customers received a $100 cash incentive for participating in the focus groups.
2. **Residential** customers were randomly selected and screened to ensure that they are the individual in their household responsible for paying the electricity bill. Residential customers received an $80 cash incentive for participating in the focus groups.

   Customer recruitment was randomly drawn from the full residential and GS<50kW customer lists that were provided by BPI from their billing database. Randomized recruitment ensured a good mix of customers representing the broader BPI low-volume customer base.

Workbook Development

A key challenge in any customer engagement related to collecting the input needed to inform a rate application, is the lack of knowledge customers have regarding Ontario's electricity system and the role of their local distributor within the system. Distribution System Plans, capital investment plans and OM&A budgets are all very detailed and extensive documents that use technical language and require specialized knowledge. Our challenge was to educate on key issues, using accessible language that customers could understand, and frame meaningful questions about customer needs and preferences, and in BPI's case, specific questions related to their new facility.

In order to inform customers on BPI's role in the system and the key investment and spending decisions it must make in the coming years, a customized workbook was created to both educate customers and collect their feedback. The workbook was the core customer engagement tool used in the focus group sessions.

Although customer experience and familiarity with Ontario's electricity system varied, the same workbook was used in both the small business and residential focus groups. The references to bill impact was varied to reflect the details of specific rate classes. As the customers went through the workbook, they were prompted with questions relating to system reliability, system challenges, and preferences on the direction of BPI's proposed facility relocation plan.

Focus Group Structure

The focus group sessions were structured around the themes contained in this workbook; with a particular focus on the proposed facility relocation plan.

- Workbooks were used as a guide throughout the focus group sessions.
- The facilitator led participants through the workbook section-by-section to ensure they understood the information and to answer any questions they had about the content.
- Participants were asked to independently respond to the questions within the workbook. At the end of each section, the facilitator then led a group discussion on the answers participants provided.

The hardcopy workbooks were collected from the participants at the conclusion of each session.

3. Detailed Feedback

The following are workbook tallies and verbatim comments written by participants in their workbooks, which were collected at the end of each focus group session. The number of verbatim comments does not correlate to the number of respondents in each group, as a number of participants did not provide responses to the open-ended questions.

3.1 Workbook Tallies and Verbatim

Q1. Before this consultation, how familiar were you with the various parts of the electricity system, how they works together and which services Brantford Power is responsible for?

	Small Business	Residential	Total
Very familiar and could explain the details of Ontario's electricty system to others	2	2	4
Somewhat familiar, but could not explain all the details of Ontario's electricity system to others	5	7	12
Have heard of some of the terms and organizations mentioned in this workbook, but knew very little about Ontario's electricity system	3	2	5
Aside from receiving a bill from Brantford Power, I knew nothing about Ontario's electricity system	1	2	3
Missing value	0	0	0
Total	**11**	**13**	**24**

Q2. Brantford Power operates and maintains the local electricity distribution system, delivers electricity throughout the community, reads meters, calculates and collects customer electricity bills, answers customer calls, responds during outages (including emergencies), clears trees from power lines and delivers electricity conservation programs. Generally, how satisfied are you with the services you receive from Brantford Power?

	Small Business	Residential	Total
Very satisfied	5	7	12
Somewhat satisfied	3	2	5
Neither satisfied nor dissatisfied	2	2	4
Somewhat dissatisfied	1	2	3
Very dissatisfied	0	0	0
Don't know	0	0	0
Missing values	0	0	0
Total	**11**	**13**	**24**

Q3. Is there anything in particular that Brantford Power can do to improve its services to you/ your organization?

Small Business
Less power shortages, maintain power to business separate from homes (residential)..
Focus more on power only; don't worry about trees or wire pulling
I have noticed that in cases of bad weather the hydro gets disconnected which disrupts the business, especially the food industry, as you have to shut down the store and let the employees go home.
Number of outages as they affect our computer server systems. Outages for 1 second cause lost data, communication stops, lost time reloading computers. We have had to install back up systems to protect our server.
Not at this time. Very happy customer.
Frequent power outages, frequent power interruptions that may last 30 minutes up to few hours, frequent power surges which has damaged my equipment, computers and other hardware, please improve reliability 100% uptime, no power fluctuations.
Dissemination of information about the cost of electricity distribution and production at each level and what percentage of it is direct cost vs indirect cost.

Residential
Reduce delivery cost, lower rate throughout the day (no off peak, mid peak, high peak), reduce initial set up cost.
Online updates of power outages and number of customers affected. PDF email bills.
Plan for the future and communicate this to the residents.
For my immediate needs? No I've had no issues for the last 10+ years.
Mandate that property owners maintain a standard of equipment that feeds off of the Brantford Power grid.
35 years no problems - I live 3 blocks away from city hall.
Have more available CS agents to answer phones, work on lowering rates, have staff be more knowledgable.
Lower costs, but everyone will say that.
As a home owner I believe Brantford Power provides very dependable electric service. I feel the system is stable, there are not many outages. There are options for billing that fit most payment options (auto withdrawl, pay at office, pay).
When a street light is out its not acceptable to wait 3 weeks for it to be 'repaired'. Removing poles and then less lighting in the evening.

Q4. Before this consultation, how familiar were you with the percentage of your electricity bill that is used by Brantford Power to cover its capital investments and operating expenses to run the utility?

	Small Business	Residential	Total
Very familiar	0	0	0
Somewhat familiar	2	5	7
Not familiar at all	9	7	16
Missing values	0	1	1
Total	**11**	**13**	**24**

Q5. Before this consultation, how familiar were you with how electricity distribution rates are set in Ontario?

	Small Business	Residential	Total
Very familiar	2	1	3
Somewhat familiar	5	4	9
Not familiar at all	4	8	12
Missing values	0	0	0
Total	**11**	**13**	**24**

Brantford Power's Relocation Plans - Customer Feedback

Q5b. Below are some of the challenges Brantford Power identified with operating out of multiple locations. Please identify which ones you feel warrant moving to a single location.

	Yes		
	Small Business	Residential	Total
Employees often need to travel between 3 locations to attend meetings, have discussions, and to access inventory, or vehicles.	10	11	21
Missed opportunities for operational efficiencies caused by having related departments located in different buildings	10	9	19
Space and configuration restraints that limit the ability for employees within the same department to be located together.	8	11	19
400 Grand River Ave. is the Emergency Response Center for Brantford Power, however, it is on a flood plain which poses a risk, as evident with the Spring 2018 flooding.	10	9	19
Limited meeting room availability with only one meeting room available at most locations.	9	9	18
There is no meeting room large enough to hold all Brantford Power employees. Therefore, training and/or corporate business meetings need to be held off-site requiring travel and additional costs.	9	9	18
While 400 Grand River Ave. represents the best option for the Emergency Center, it has limited space to operate as a central command centre for all employees and other emergency personnel.	9	9	18
Some managers have responsibilities at multiple locations, requiring travel and duplication of some costs such as office furtniture, parking spaces, etc.	9	9	18
Challenges to building a cohesive corporate culture and improving employee engagement in order to retain key, skilled employees.	7	9	16
Meeting rooms at each location are shared with other (non-Brantford Power) parties and may be unavailable when needed and/or for long periods of time.	7	8	15
The combination of all of the issues listed above warrants relocation.	9	9	18

Q6. Do you support or oppose Brantford Power entering into a joint agreement to operate a shared facility?

	Small Business	Residential	Total
Strongly support	9	6	15
Somewhat support	1	5	6
Somewhat oppose	0	0	0
Strongly oppose	1	1	2
Don't know	0	0	0
Missing values	0	1	1
Total	**11**	**13**	**24**

Q7. How well do you feel you understand the reasons for Brantford Power's relocation?

	Small Business	Residential	Total
Very well	5	7	12
Somewhat well	6	6	12
Not very well	0	0	0
Not well at all	0	0	0
Don't know	0	0	0
Missing values	0	0	0
Total	**11**	**13**	**24**

Q8. How would you rate the urgency of Brantford Power's need to relocate?

	Small Business	Residential	Total
Very urgent	5	7	12
Somewhat urgent	5	4	9
Not very urgent	1	2	3
Not at all urgent	0	0	0
Don't know	0	0	0
Missing values	0	0	0
Total	**11**	**13**	**24**

Q9. Does Brantford Power's plan to relocate to a single building seem unreasonable to you?

	Small Business	Residential	Total
No, it seems reasonable	10	12	22
Unreasonable	1	1	2
Missing values	0	0	0
Total	**11**	**13**	**24**

Q9a. If the plan seems unreasonable to you, please tell us why in the space provided below.

Small Business
Administration does not need to be with operations. Nice, but not necessary.

Residential
Increased cost … Brantford power should work with what they have.

Q10. Do you support or oppose Brantford Power's plan to share the new building with Energy+, Enersure and NetOptiks?

	Small Business	Residential	Total
Strongly support	8	9	17
Somewhat support	2	2	4
Somewhat oppose	1	0	1
Strongly oppose	0	1	1
Don't know	0	1	1
Missing values	0	0	0
Total	**11**	**13**	**24**

Q11. What do you think the impact of Brantford Power's relocation into a shared new facility will be on customers?

	Small Business	Residential	Total
Better customer service	5	8	13
No impact	5	5	10
Worse customer service	0	0	0
Don't know	1	0	1
Missing values	0	0	0
Total	**11**	**13**	**24**

Q12. Considering what you know about the plans for Brantford Power's relocation and its impact on your organization's/household's rates, which of the following best represents your point of view?

	Small Business	Residential	Total
The proposed rate increase is reasonable and I support it	0	5	5
I don't like it, but I think the proposed rate increase is necessary	7	5	12
The proposed rate increase is unreasonable and I oppose it	4	3	7
Don't know	0	0	0
Missing value	0	0	0
Total	**11**	**13**	**24**

Q13. Why did you choose your response to question 12 above?

Small Business
I don't like it, but I think the proposed rate increase is necessary
Brantford Power needs to move and it isn't going to pay for itself.
Rates are already high, so I do not support any increases, however, I do agree with the need to relocate and the proposed plan. This will hopefully allow for better service and reliability. Unfortunately this does not address the frequent interruptions in power customers like myself are currently experiencing.
The proposed rate increase is unreasonable and I oppose it
The new building should come out of the profit margin rather than customers paying for it. There is no true reason for customers having to pay?
The proposed rate increase information provided in the workbook did not specify what kind of savings will be achieved through the process of consolidation as well the impact of revenue stream generated through the rent collection. If Brantford Power was paying rent at various buildings then those rent savings need to be accounted for. Overall, I feel that not enough information is provided in this book to be able for me to properly access it. Generally speaking the savings in rent and consolidation should be able to pay for the cost of capital expenditure. Keeping our rates the same.
The case is not good enough, we should have kept the PUC as it was where water and hydro were not connected to the city. The city took over the PUC and the money in the bank from the PUC.
We should not be paying for a building. Many people 'travel' for meetings. Perhaps meetings could be better utilized by doing video conferences.

Residential
The proposed rate increase is reasonable and I support it
It is important to service the customers appropriately and through this way they are able to appropriately plan.
I think it is difficult running a business out of aging facilities. It always helps when you are able to work with lots of space.
Needed.
Because it’s a reasonable amount, I understand the reason and where the money is going.
I don't like it, but I think the proposed rate increase is necessary
I find it hard to see the increase for so long. What rent charges are they savings? Still have such a large cost to finance. Is the building going to be fancy and not really utilized but fullfill management dreams of a grandiose building?
I don't like the thought of paying more, but knowing this will in turn be a better business plan for Brantford Power (lower costs of building).
Not enough information in this package to know if the $2.06 -> $2.57 is based on capital purchases ammortized over a number of years? Some un-answered questions, more clarity on ownership.
I don't like paying more, but it's sometimes needed.
The current spread of employees, equipment it is silly. Amalgomate and share resources is a good idea.
The proposed rate increase is unreasonable and I oppose it
Estimated increase in electricity cost is not actual increase. Find an alternative that will not result in an increase in electricity costs.
Hydro rates are unreasonable now. The new ON government is reducing rates due to the high rates. The previous government made serious errors and it has been pushed onto us.
Try other options first in order to accommodate the rate increase. For example, negotiate with hydro one to lower the ever-increasing generating costs for a period of time to get the money needed. (I guess this is fixed by the OEB). Also the forward thinking plan of owning their own building seems like it should have been done a long time ago (management could have consolidated and purchased a building then).

Q14. Based on what you had read, seen or heard previously, and the information shared with you tonight, how satisfied are you that Brantford Power considered all options available to them before moving forward with the new facility, shared space arrangement?

	Small Business	Residential	Total
Very satisfied	2	8	10
Somewhat satisfied	2	3	5
Somewhat dissatisfied	1	2	3
Very dissatisfied	1	0	1
Don't know	5	0	5
Missing values	0	0	0
Total	**11**	**13**	**24**

3.2 Process Assessment

Overall Impression: What did you think about the workbook?

Small Business
It has a lot of info!
OK
Thorough and informative
OK
Good
A great attempt to educate customers but falls short of providing proper breakdowns on costs

Residential
Good basic info, missing profit %, no real explanation why such an increase for so long
Interesting biased book to support Brantford's decision. They've made up their mind and want to brainwash you to support their decision.
Lots of background information provided and visually appealing
Very informative
I like the information was provided where I previously had no knowledge of that.
Informative, mostly detailed in explaining whats happening
Could have came out, here's the situation, here is what we thought about it, here's our research,what do you think about it
Very informative, well plotted out
Nice design
Appreciate the most up to date info
Informative
Great

Volume of Information: Did Brantford Power provide too much information, not enough, or just the right amount?

Small Business
It has a lot of info!
OK
Thorough and informative.
OK
Good
A great attempt to educate customers but falls short of providing proper breakdowns on costs.

Residential
Good basic info, missing profit %, no real explanation why such an increase for so long.
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Very informative, well plotted out.
Nice design.
Appreciate the most up-to-date info.
Informative
Great

Content Covered: Was there any content missing that you would have liked to have seen included?

Small Business
I don't feel anything was missing
Increase in the monthly charge should have been mentioned (time line)
Brantford Power's cost breakdown and annual revenue
What portion of these costs are being recovered by "sharing"? Why can't the "sharing partners" pay for the building?
Why did the city take over the PUC and leave it in this condition.
Breakdown of savings achieved through consolidation and space, sharing. Breakdown of cost into actual operating expenses and indirect expenses.

Residential
Rent savings - savings by having everyone in the same place. You are saying even with all these savings it will cost this much per month.
More alternatives that will not increase monthly costs.
How other smaller utility companies have dealth with building projects.
All past efforts detailed.
Not really.
Not that I can name.
Job application
No, just right.
Nope.
Info on future oriented plans that Brantford power has to keep up with what other forward thinking places are doing.

Outstanding Questions: Is there anything that you would like answered?

Small Business
All questions were answered.
What impact will this relocation have on reliability and service?
How long do we have to pay this new building?
No
A complete analysis of cost breakdown used for the decision making.

Residential
What are areas of focus with dollar/month where they could be cut if the building is not approved.
Efficiencies possibilities.
What is the total cost of new buildings?
No
No
No
No
No

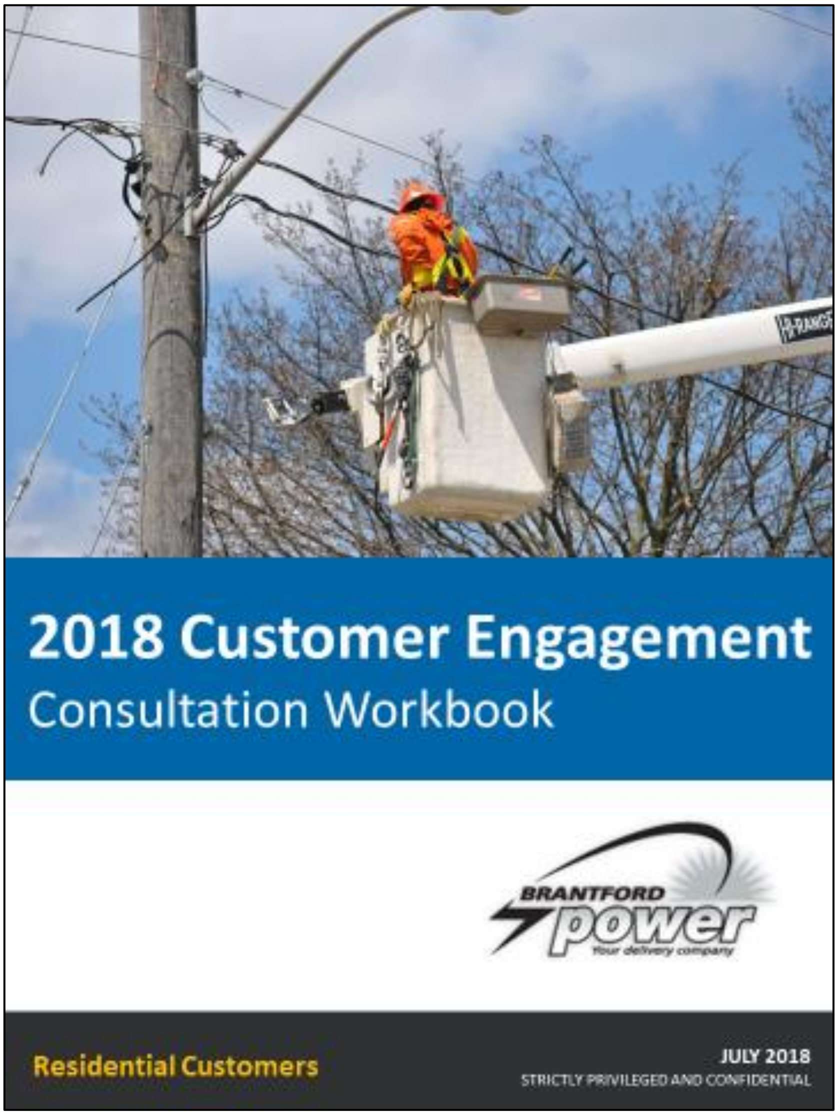
Suggestions for Future Consultations: How would you prefer to participate in these consultations?

Small Business
I think focus group works well.
This consultation is the best preference.
More information is required.
Through personal contact.
Surveys and sessions like tonights.
Don't know.

Residential
The discussion was well organized.
Maybe a little more information as to when more consultations like this will be happening.
I think this type is a good format.
I liked this panel idea because of the shared ideas from others as well as information others provided.
Online
Enjoyed the process and discussion.
Do it online, take as much time as we needed to review the materials.
Online, on my own time.

4. Focus Group Stimuli (Workbook)

Residential Consultation Workbook



2018 Customer Engagement
Consultation Workbook

BRANTFORD power
Your delivery company

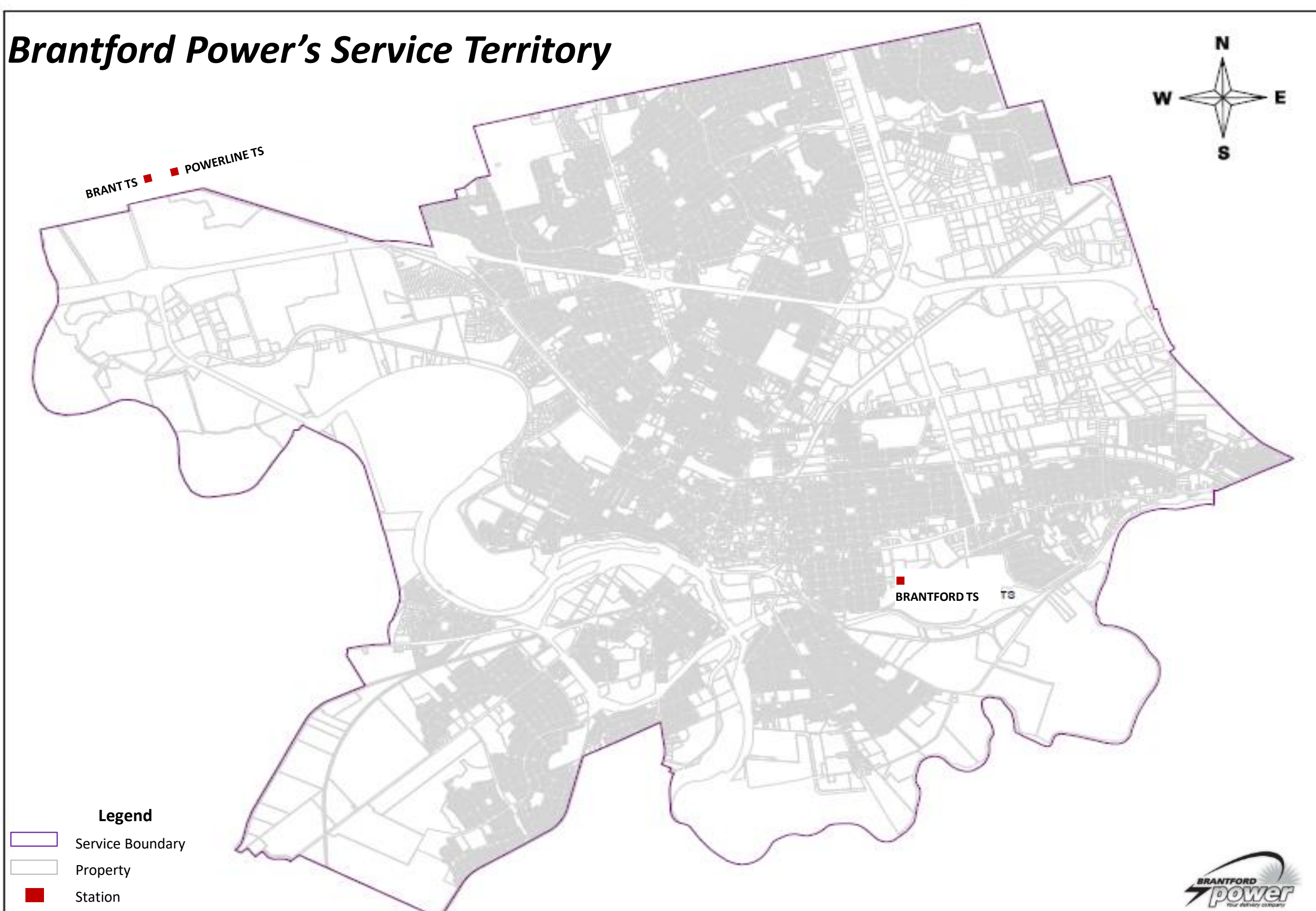
Residential Customers

JULY 2018
STRICTLY PRIVILEGED AND CONFIDENTIAL

Brantford Power Inc. is the local distribution company responsible for electricity distribution in the City of Brantford.

With approximately 60 employees, Brantford Power operates and maintains a distribution system serving a population of approximately 99,000 with about 40,000 residential and business customers over a 74 square kilometre area.

Brantford Power has been operating since 1935 and is wholly owned by the City of Brantford through its holding company, the Brantford Energy Corporation.



Brantford Power's Service Territory

What is This Consultation About?

The purpose of this consultation is to collect your feedback on Brantford Power's upcoming application to the Ontario Energy Board (OEB).

Your feedback will provide insight into customer preferences and needs which will then be incorporated into Brantford Power's application.

- In Ontario, electricity distributors – such as Brantford Power – are regulated by the Ontario Energy Board (OEB), the provincial energy regulator.
- Brantford Power is in the process of preparing an application to be submitted to the OEB in order to adjust customer rates.
- The OEB must approve the application and may opt to amend or deny specific aspects of it.

You don't need to be an expert to participate in this consultation. You only need to be a customer.

The goal is to understand your point of view as a customer. You will be asked to provide your feedback and insights in a number of areas related to this application.

This workbook is designed to give you enough background about these issues for you to develop an informed opinion.

The most important parts of this workbook are the survey questions.

The goal of this workbook is to understand the general priorities and criteria you would like Brantford Power to use when making key business decisions.

Brantford Power is looking to develop a genuine understanding of its customers' views, which will help shape this and future applications to the OEB.

As such, the most import parts of this workbook are the survey questions. While your view may not always align exactly with the available options, please select the one that is closest to your point of view. If you are truly unsure, select the "don't know" option.

Your privacy will be protected.

Brantford Power has engaged an independent research firm, *Innovative Research Group*, to document your views. All individual responses will be confidential. Your feedback will be combined with others in any reporting.

Electricity 101

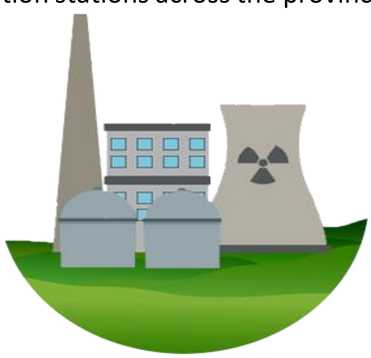
Understanding Brantford Power's role in Ontario's electricity system

Ontario's electricity system is owned and operated by public, private and municipal corporations across the province. It is made up of three key components: **generation**, **transmission** and **local distribution**.

1 Generation

Where electricity comes from.

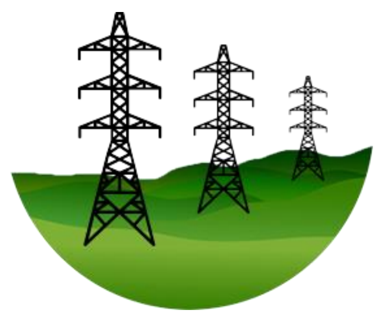
Ontario's electricity is generated by nuclear, and natural gas, hydroelectric and renewable technologies such as wind and solar. In Ontario, 70% of electricity is generated by Ontario Power Generation, which has generation stations across the province.



2 Transmission

Electricity travels across Ontario.

Once electricity is generated, it must be transported to urban and rural areas across the province. This happens by way of high voltage transmission lines that serve as highways for electricity. The province has more than 30,000 kilometres of transmission lines.



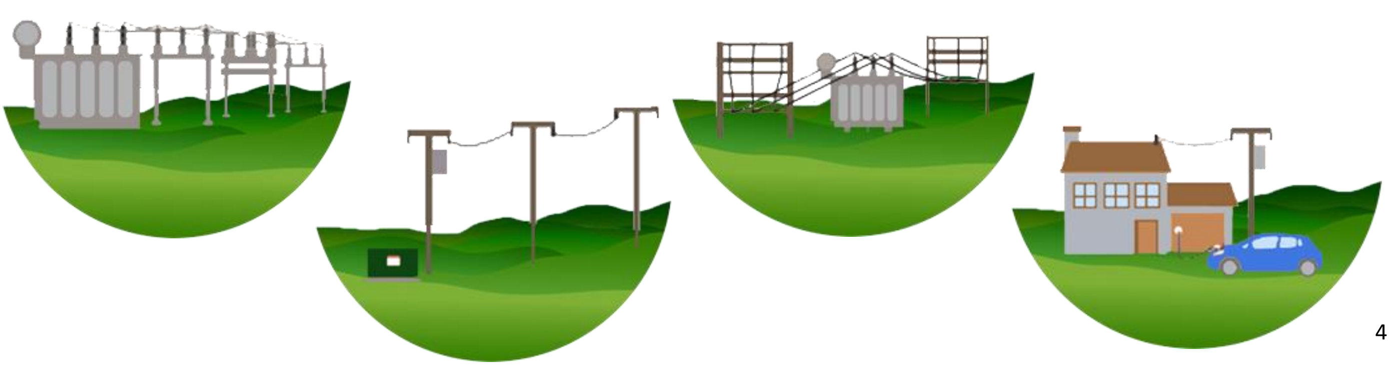
3 Local Distribution

Delivering power to homes and businesses in the City of Brantford.

Brantford Power is responsible for the last step of the journey: distributing electricity to customers through its distribution system. This local distribution system includes transformer stations that decrease the voltage of the electricity so it can be used in your home or business.

Brantford Power is responsible for maintaining distribution and infrastructure assets deployed over 74 square kilometres of urban area. The distribution system contains approximately 269km of overhead wires, 238km of underground cables, and 3,504 distribution transformers.

Brantford Power is also responsible for the services associated with reading meters, billing, general customer service and responding to outages and emergencies.



Brantford Power's Distribution System

Every distribution system is unique with its own history and challenges. In order to better understand Brantford Power's distribution system, we first have to understand all of the different components and how they impact the way in which you receive electricity when you need it.

High Voltage Transmission: Hydro One's high voltage transmission lines connect Brantford Power's distribution system to electricity generating stations across the province.

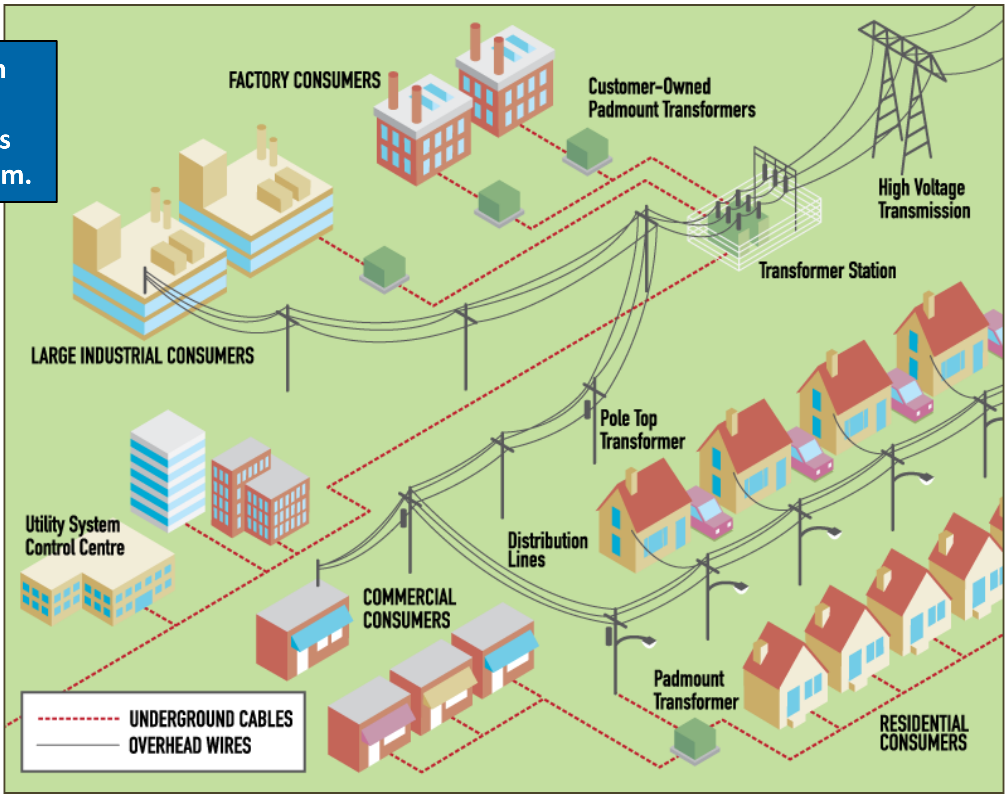
Transformer Stations: Reduce high voltage electricity from transmission lines to medium voltage electricity, which is fed into Brantford Power's distribution feeder system.

Overhead System: The overhead system includes the wires, poles and pole top transformers that are commonly seen across Brantford Power's service territory.

Underground System: The underground system includes underground cables, transformers and switches.

Assets owned by Brantford Power	# in System
Transmission Stations	1
Pole Mounted Transformers	1,463
Submersible Transformers	160
Padmount Transformers	1,881
Overhead Switches	791
Padmount / Underground Switches	271
Overhead Conductor (km)	269
Underground Cable (km)	237
Poles – Wood	9,001
Poles – Concrete	997

This diagram is an illustration of Brantford Power's distribution system.



Customer Feedback

Satisfaction & areas for improvement

1. **Before this consultation, how familiar were you with the various parts of the electricity system, how they work together and which services Brantford Power is responsible for?**

   - ❑ Very familiar and could explain the details of Ontario's electricity system to others
   - ❑ Somewhat familiar, but could not explain all the details of Ontario's electricity system to others
   - ❑ Have heard of some of the terms and organizations mentioned in this workbook, but knew very little about Ontario's electricity system
   - ❑ Aside from receiving a bill from **Brantford Power**, I knew nothing about Ontario's electricity system

2. **Brantford Power operates and maintains the local electricity distribution system, delivers electricity throughout the community, reads meters, calculates and collects customer electricity bills, answers customer calls, responds during outages (including emergencies), clears trees from power lines and delivers electricity conservation programs.**

   Generally, how satisfied are you with the services you receive from Brantford Power?

   - ❑ Very satisfied
   - ❑ Somewhat satisfied
   - ❑ Neither satisfied nor dissatisfied
   - ❑ Somewhat dissatisfied
   - ❑ Very dissatisfied
   - ❑ Don't know

3. **Is there anything in particular that Brantford Power can do to improve its services to you?**

Brantford Power's Distribution System Today

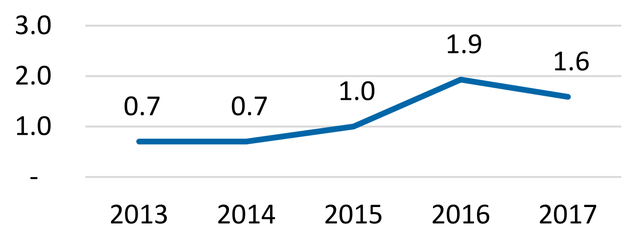
System Reliability

No distribution system can deliver 100% reliable electrical service. From time to time, customers will experience an electrical service interruption. Generally, the more reliable the system, the more expensive it is to build, maintain and operate.

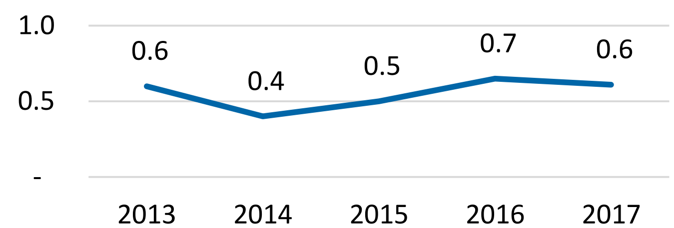
Electrical distribution systems are outdoors and subject to sun, wind, rain, lightning, ice, falling tree branches, vehicle accidents, animal contact, excavations (on underground power cables) and natural aging. Brantford Power faces a balancing act between keeping costs as low as possible and reducing the number and length of outages.

For most customers, the key test of system reliability is "**Do the lights stay on?**" Brantford Power strives to minimize both the number of outages that customers experience and the length of time the power is out. Outage statistics *(shown below)* – consisting of outages lasting a minute or more – are compiled by Brantford Power to help identify and focus on specific issues that may affect reliability.

Average # of Outages per Customer per Year



Length of Outages (hours) per Customer per Year

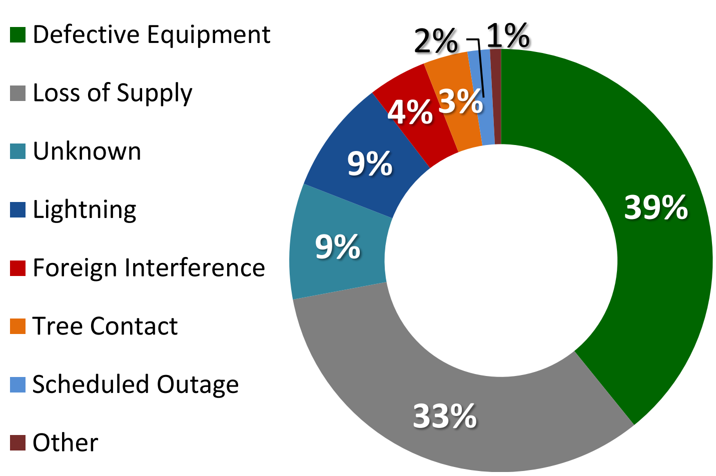


The table below illustrates how Brantford Power's reliability statistics compare with neighbouring utilities:

2016* Reliability Indicator ** Most recent available OEB data*	**Brantford Power**	**Energy+**	**Hydro One**	**Alectra Utilities**	**Guelph Hydro**
Average # of Outages per Customer per Year	**1.9**	2.0	3.4	2.0	2.2
Average Outage Duration (hours/ year)	**0.7**	1.9	13.2	1.6	1.1

Causes of Power Interruptions (2017)

The outage analysis and system performance measures provide an overview of the performance of Brantford Power's distribution system in 2017. It is based on the raw data provided for incidents and outages. This data enhances Brantford Power's asset management plan by identifying future maintenance and capital budget priorities to improve the reliability and performance of the distribution system.



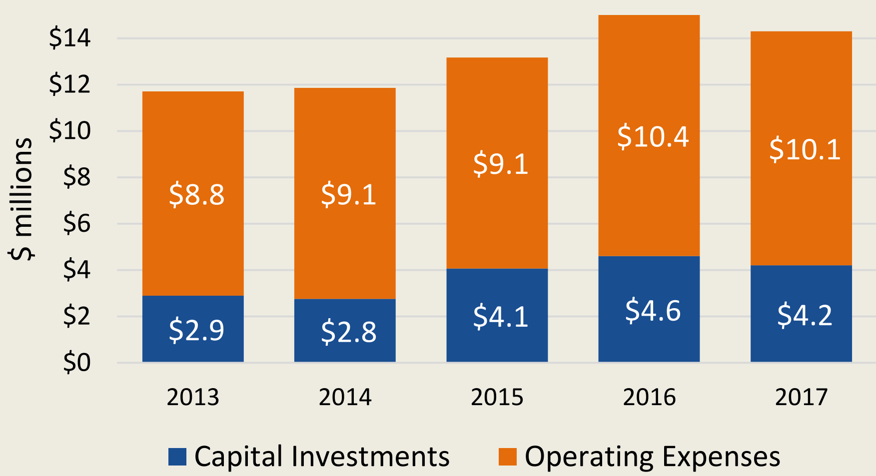
How Brantford Power Operates

Understanding where your money goes

Like most businesses, Brantford Power manages its spending in two budgets – an operating budget and a capital budget.

- Brantford Power's **operating budget** covers recurring expenses, such as the maintenance of tools, equipment and assets and the payroll for employees.
- Its **capital budget** covers items that, once purchased, have lasting benefits over many years. This includes much of the equipment that is part of the distribution system, such as poles, wires, cables, transformers, computers and information systems, vehicles and facilities.

Historical Operating Expenses and Capital Investments



Managing the distribution system requires millions of dollars in maintenance, system renewal and day-to-day operations. In 2017, the combined operating expenses and capital investments of Brantford Power totalled **$14.3 million**.

How does Brantford Power set its budget?

- Utilities do not operate in competitive markets like most private businesses. Customers cannot choose who delivers power to their homes and businesses. Brantford Power is the only electricity distribution choice in the City of Brantford. Brantford Power is highly regulated to ensure that it offers its customers reliable services at a reasonable cost.
- Regulated utilities, such as Brantford Power, set their budgets based on forecasts of what is needed to operate and maintain the distribution system. The cost of providing utility services is reviewed and must be approved by the OEB.

Does Brantford Power make a profit?

- Yes, a profit is built into its rate design. Like all regulated utilities in Ontario, Brantford Power can generate a profit based on a target set by the OEB. A portion of this profit is reinvested in the business with the remainder paid out in the form of an annual dividend to its shareholder which may be transferred to the City of Brantford to fund services such as roads, parks, and other municipal programs.

Electricity Bills

Understanding where your money goes

Every item and charge on your bill is either mandated by the provincial government or approved by the Ontario Energy Board.

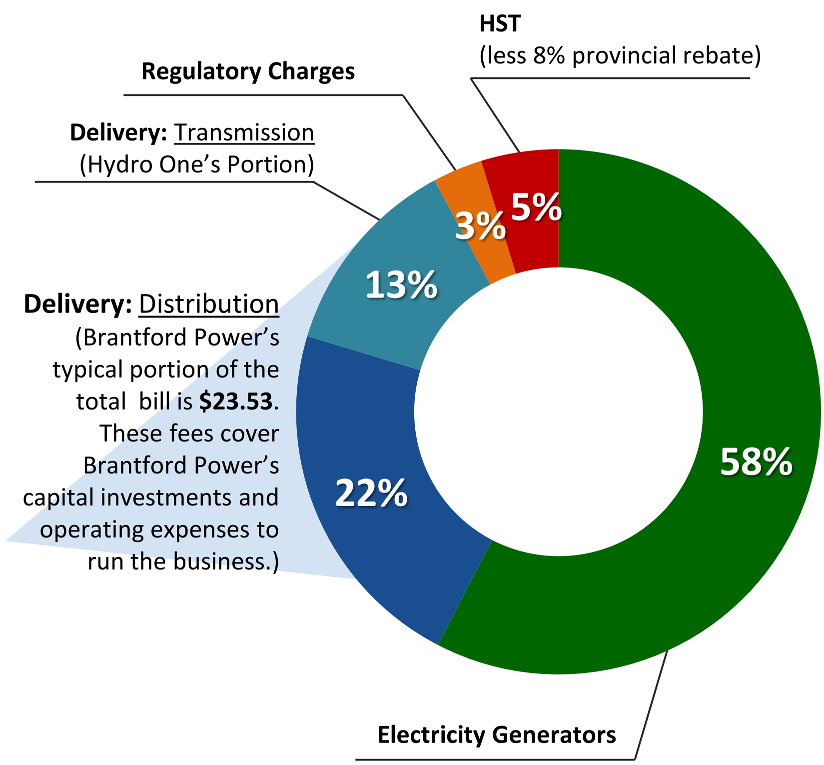
For the typical residential customer, about **22%** per month of the electricity bill goes to pay for the **Brantford Power** distribution system. The rest of the bill goes to power generation companies, transmission companies, regulatory agencies, and government taxes.

Brantford Power is responsible for billing customers for all of these costs, including any applicable taxes. The "Delivery" charge pays for both the cost of transmission and the cost of distribution. Only the distribution portion is retained by **Brantford Power** to pay for its part of the system.

Sample Residential Bill

SAMPLE RESIDENTIAL MONTHLY BILL	
Brantford Power Inc.	
Account Number: 000 000 000 000 0000	
Meter Number: 0000000	
Your Electricity Charges	
Electricity	
Off-peak @6.5 ₵/kWh	31.69
Mid-peak @9.4 ₵/kWh	11.99
On-peak @13.2 ₵/kWh	17.82
Delivery (BPI $23.53)	36.90
Regulatory Charges	3.27
Total Electricity Charges	**$101.66**
HST	13.22
8% Provincial Rebate*	**-($8.13)**
* The Ontario government is providing a rebate on your electricity costs equal to the provincial portion of the HST	
Total Amount	**$106.74**

Brantford Power's portion: **$23.53**



Note: *Graphs may not always total 100% due to rounding.*

4. Before this consultation, how familiar were you with the percentage of your electricity bill that is used by Brantford Power to cover its capital investments and operating expenses to run the utility?

- ☐ Very familiar
- ☐ Somewhat familiar
- ☐ Not familiar at all

How are Electricity Distribution Rates Set in Ontario?

The electricity industry in Ontario is regulated by the Ontario Energy Board (OEB). The OEB sets electricity rates in Ontario.

The OEB requires electricity distributors, such as **Brantford Power**, to develop its business plan and distribution system plan, as well as make spending and investment decisions based on customer feedback.

ONTARIO ENERGY BOARD

Electricity distributors are funded by the distribution rates paid by their customers. Periodically, distributors are required to file rate applications with the OEB to justify the amount of funding they need to safely and reliably distribute electricity to their customers.

Brantford Power's 2017 Rate Application

The rates you pay to Brantford Power are set by the OEB through a public process. Brantford Power's current rates were approved in a 2017 application and will be in place until 2021. Each year Brantford Power is permitted to increase rates to reflect inflation minus savings targets established by the OEB which requires Brantford Power to keep cost increases below inflation.

5. Before this consultation, how familiar were you with how electricity distribution rates are set in Ontario?

- ☐ Very familiar
- ☐ Somewhat familiar
- ☐ Not familiar at all

Planning for the Future

Understanding the challenges facing Brantford Power

Planning Challenges:

Brantford Power is committed to delivering safe, efficient and reliable electricity to its customers. Keeping this promise involves more than maintaining the physical assets that make up the Brantford Power distribution system. Like all businesses, Brantford Power must keep on eye on multiple overlapping planning challenges to ensure they are well-prepared for the future.

Future Challenges and Risks:

- Expertise of existing workforce = superior reliability and customer service
- Some key current employees will be ready for retirement in the next few years
- Recruitment, training, retention

Potential Future Impacts:

- Increased cost of recruitment and training
- New employees could negatively affect reliability, outage response and customer service

Future Challenges and Risks:

- Communication between departments and decision-making need to be efficient to meet standards for customer service, reliability and emergency preparedness
- Customers' communications expectations are increasing (billing, outages, etc.)

Potential Future Impacts:

- Cost impacts of inefficient communication
  - Delayed outage response
    - Delayed or uncertain communication to customers

Future Challenges and Risks:

- New technologies = customer demand for electric vehicles, renewable generation, battery storage, etc.
- All have specific requirements which could have major implications on distribution system

Potential Future Impacts:

- Ability to meet customer demand for new technology:
  - Reliability impacts
  - Potential cost impacts

Future Challenges and Risks:

- Recent increase in potential emergency situations (2018 flood, 2018 wind storms)
- Brantford Power emergency centre (which houses equipment & crew) is located on a flood plain
- Increased expectations for communication of emergency updates

Potential Future Impacts:

- Potential for increased safety risk
- Ability to restore power in an emergency
- Ability to communicate restoration times to customers

The following pages describe how Brantford Power has responded to a challenge that impacts all of their future planning.

2020 Incremental Capital Needs

As part of the OEB policies, there is an option for Brantford Power to apply for additional rate increases for discrete projects that are prudent, needed and not supported by existing rates. Looking ahead to 2020, Brantford Power has identified a project that needs more investment than the existing budget allows.

Brantford Power's Facility Relocation

Prior to its 2017 rate application, Brantford Power began to feel the pressure to explore alternatives to its current facilities arrangements.

Currently, Brantford Power's staff and equipment are housed in multiple locations across Brantford, all of which are rented from the City of Brantford. While operating as a fragmented organization is less than ideal, Brantford Power in its efforts to be prudent with its expenditures and as a good steward of electricity ratepayer dollars, has made the best of this arrangement.

As the City of Brantford contemplates its own accommodation challenges, the buildings Brantford Power currently occupies and shares with the City have either been divested of, or identified for possible repurposing. As such, the current situation is no longer sustainable for the utility to operate.

At the time of its 2017 rate application, Brantford Power did apply to include a forecast cost for its facility relocation. However, as the original facility relocation plan was not viable due to external factors, Brantford Power removed this request and **the facility relocation was not included in 2017 rates.**

Now, after a nearly four-year rigorous process, Brantford Power believes it has found the optimal solution to its facility relocation that will allow Brantford Power to serve the Brantford community at the levels it is accustomed to for generations to come, as well as minimize the customer bill impact.

This facility relocation – which is subject to customer feedback and OEB approval – could result in an increase of $2.06 to $2.57 per month on the distribution portion of your electricity bill.

The remaining few pages of this workbook with focus on exploring how Brantford Power developed its preliminary relocation plans, as well as gather your feedback on how you believe the utility should proceed.

Brantford Power’s Relocation Plans

The utility’s current arrangement

Current Arrangement

At present, Brantford Power rents or leases three buildings from the City of Brantford:

400 Grand River Avenue is home to Brantford Power’s operations, stores/inventory, and vehicle garage. They share this location with Brantford Transit.

84 Market Street is the office space for the finance, administration and engineering departments. This location is also shared with the City of Brantford.

220 Colborne Street is where Brantford Power’s customer care, billing, settlement, and conservation services are based. They share this location with the City of Brantford.

Why does this need to change?

The City of Brantford has sold 220 Colborne to Wilfrid Laurier University and they are in the process of repurposing the other two locations that Brantford Power currently occupies. In 2016, the City of Brantford notified Brantford Power that the three current facilities may not be available in the medium to long term. In 2018, the City gave Brantford Power official notice that the existing leases will not be renewed.

So, Brantford Power has no choice – they have to move.

Brantford Power's Relocation Plans

Customer feedback

Having spent decades spread across three separate locations, Brantford Power realized there were several challenges with that arrangement. These challenges were taken into account when Brantford Power was trying to decide what would be the best option for relocation.

Below are some of the challenges Brantford Power identified with operating out of multiple locations. Please identify which ones you feel warrant moving to a single location.

	Yes	No
Missed opportunities for operational efficiencies caused by having related departments located in different buildings.	☐	☐
Employees often need to travel between 3 locations to attend meetings, have key discussions, and to access inventory, or vehicles.	☐	☐
Challenges to building a cohesive corporate culture and improving employee engagement in order to retain key, skilled employees.	☐	☐
Space and configuration constraints that limit the ability to for employees within the same department to be located together.	☐	☐
Limited meeting room availability with only one meeting room available at most locations.	☐	☐
Meeting rooms at each location are shared with other (non-Brantford Power) parties and may be unavailable when needed and/or for long periods of time.	☐	☐
There is no meeting room large enough to hold all Brantford Power employees. Therefore, training and/or corporate business meetings need to be held off-site, requiring travel and additional costs.	☐	☐
400 Grand River Ave. is the Emergency Response Centre for Brantford Power, however, it is on a flood plain which poses a risk, as evident with the Spring 2018 flooding.	☐	☐
While 400 Grand River Ave. represents the best option for the Emergency Centre, it has limited space to operate as a central command centre for all employees and other emergency personnel.	☐	☐
Some managers have responsibilities at multiple locations, requiring travel and duplication of some costs such as office furniture, parking spaces, etc.	☐	☐
The combination of <u>all of the issues listed above</u> warrants relocation.	☐	☐

Brantford Power's Relocation Plans

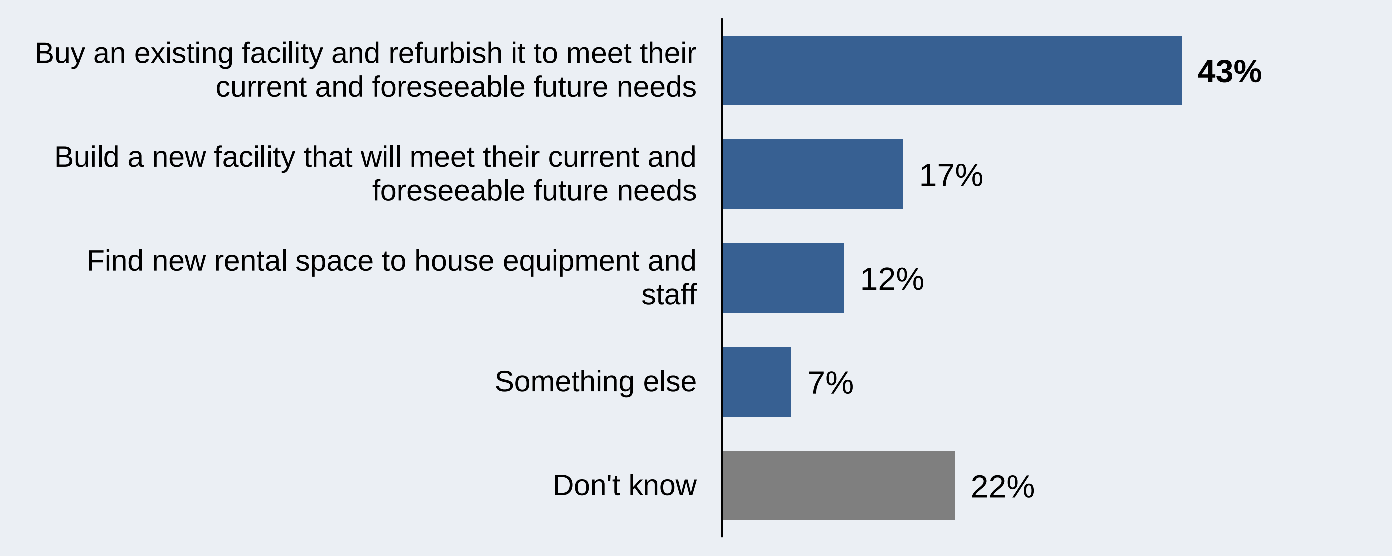
Timeline of events

2014	Brantford Power identifies medium to long- term risk for existing leasing arrangements, begins to plan for a facility relocation.
November 2014	Brantford Power works with a qualified third party to assess its facility requirements: lot size; internal and external equipment and vehicle storage space; office space; meeting rooms and other specialty spaces. The consultant applied a recognized standard of assumptions in determining the space requirements specific to Brantford Power's number and type of employees and its operational requirements. In addition to the recommended ranges of each type of space identified by this consultant's report, Brantford Power adds additional criteria to the requirements for its new facility including location within Brantford, appropriate pricing, and relatively quick availability of space.
February 2015	Working with a qualified commercial real estate consultant, Brantford Power begins to assess the options available for its facility relocation, with a preference for existing buildings which would be available more quickly than a new-build option. Brantford Power and its consultant review dozens of properties, including existing buildings for sale and for lease, as well as empty land, and new lease developments. None of the existing options meet all of Brantford Power's criteria, with most options not meeting the lot size, warehouse space and office space ranges.
March 2015	Brantford Power selects one existing property, which would meet most (but not all) of its requirements if refurbished, and actively pursues this option for some time, while still investigating new options available on the commercial real estate market.
February 2016	Brantford Power consults its customers through a work book on its proposals for the next five-year period, including the proposal to purchase and refurbish a new building. The customer feedback outlines a general understanding of Brantford Power's circumstances with respect to the facility relocation, and a customer preference for a purchase and rebuild option as well as feedback that Brantford Power should work with qualified third parties in its relocation.
January 2017	Having exhausted negotiations on the already existing property which had begun in 2015, Brantford Power purchases and empty lot on Garden Avenue.
Early 2017	Brantford Power and its neighbouring utility, Energy+, which serves the City of Cambridge, the Township of North Dumfries and Brant County, begin discussions regarding the potential to enter into a shared space agreement which would result in cost and service advantages to each utility's customers.
March 2017	With the help of third party consultants, selected and retained through open, competitive processes, Brantford Power begins the design of a new building which will be occupied by Brantford Power's full employees and equipment, some of Energy+'s operations, and an affiliate of Brantford Power's, which operates the brands Enersure and NetOptiks. The objectives of the design are to provide a functional, durable facility which will allow Brantford Power to serve its customers with a view to mitigating customer rate impacts.
2017-2018	Throughout 2017, Brantford Power worked with qualified professionals to determine its detailed needs and develop an architectural design. Brantford Power has also gone to market to obtain the best financing plan and rate available.

What Brantford Power Customers Said in 2016

In 2016, as part of their rate application to the OEB, Brantford Power undertook a customer consultation that involved focus groups, an online workbook survey and a telephone survey. In the online and telephone surveys, Brantford Power asked customers for their input on which relocation option they should pursue.

At the time, 43% of residential customers interviewed in the telephone survey believed that Brantford Power should **buy and refurbish** a facility to meet their future needs.



However, after this survey had already been completed, and the results shared with the OEB, it turned out that – due to circumstances beyond the utility's control – the option of purchasing and refurbishing an existing building was no longer an option for Brantford Power. As a result, Brantford Power and Energy+ began discussing the possibility of a **shared space agreement**. By sharing the new building with Energy+ (the electricity utility that serves Cambridge, North Dumfries and Brant County), Enersure and NetOptiks, Brantford Power is anticipating several benefits:

- **Reduced fixed costs** associated with the new building, which will mitigate the rate impact to customers.
- **Potential for reductions to operating costs** through shared services with Energy+.
- **Potential for improved customer service** in terms of restoring power after outages and reducing emergency response times.

What is Being Proposed?

Brantford Power has entered into an agreement that will see the utility operate a shared facility with Energy+, NetOptiks and Enersure.

As previously mentioned, this shared facility will both help mitigate costs as well as improve customer service for Brantford Power's customers compared to investing in its own relocation.

What other options did Brantford Power explore?

With limited suitable existing properties or vacant land in the City of Brantford, the utility believes that it has selected both the most cost-effective and efficient relocation option.

The new location will allow Brantford Power quick access to key transportation arteries such as Hwy. 403, for easy access to its customers.

Brantford Power estimated that the utility's "stand-alone" building costs would be in the range of **\$2.7M-\$3.2M higher** than the current shared proposal.

- One great example of the sharing mechanism is the cost of the land—the purchase price for the current lot would have been the same with or without tenants. However, by sharing with Energy+ and NetOptiks/Enersure, Brantford Power will pass on a portion of the land cost to its tenants, lowering the impact to ratepayers.

6. Do you support or oppose Brantford Power entering into a joint agreement to operate a shared facility?

□ Strongly support
□ Somewhat support
□ Somewhat oppose
□ Strongly oppose
□ Don't know

Customer Feedback
Brantford Power's relocation plans

7. How well do you feel you understand the reasons for Brantford Power's relocation?

- ❑ Very well
- ❑ Somewhat well
- ❑ Not very well
- ❑ Not well at all
- ❑ Don't know

8. How would you rate the urgency of Brantford Power's need to relocate?

- ❑ Very urgent
- ❑ Somewhat urgent
- ❑ Not very urgent
- ❑ Not at all urgent
- ❑ Don't know

9. Does Brantford Power's plan to relocate to a single building seem unreasonable to you?

- ❑ No, it seems reasonable

If the plan seems unreasonable to you, please tell us why in the space provided below.

10. Do you support or oppose Brantford Power's plan to share the new building with Energy+, Enersure and NetOptiks?

- ❑ Strongly support
- ❑ Somewhat support
- ❑ Somewhat oppose
- ❑ Strongly oppose
- ❑ Don't know

11. What do you think the impact of Brantford Power's relocation into a shared new facility will be on customers?

- ❑ Better customer service
- ❑ No impact
- ❑ Worse customer service
- ❑ Don't know

Expected Capital Cost and Bill Impact

Breaking ground at the site of the new building is expected to take place in 2018. Brantford Power anticipates that occupancy will occur in late 2019 or early 2020.

An additional $19 million in capital will be required to cover Brantford Power's portion of the building costs, based on most recent estimates.

Brantford Power's proposal to the OEB for the costs to be recovered from Brantford Power customers will be limited to the costs of the building related to Brantford Power's requirements for serving its customers.

In other words, Brantford Power customers will <u>not</u> be subsidizing Energy+, Enersure or NetOptiks customers.

Residential Bill Impact

As a result of Brantford Power moving into a new facility, effective January 1, 2020, the average residential household will be paying an **estimated additional $2.06 to $2.57 per month**.

Customer Feedback

Rate impact of Brantford Power's proposed relocation

12. Considering what you know about the plans for Brantford Power's relocation and its impact on your organization's rates, which of the following best represents your point of view?

- ❑ The proposed rate increase is reasonable and I support it
- ❑ I don't like it, but I think the proposed rate increase is necessary
- ❑ The proposed rate increase is unreasonable and I oppose it
- ❑ Don't know

13. Why did you choose your response to question 12 above?

14. Based on what you had read, seen or heard previously, and the information shared with you tonight, how satisfied are you that Brantford Power considered all options available to them before moving forward with the new facility, shared space arrangement?

- ❑ Very satisfied
- ❑ Somewhat satisfied
- ❑ Somewhat dissatisfied
- ❑ Very dissatisfied
- ❑ Don't know

Customer Feedback
Final Thoughts

Thank you for participating. Brantford Power values your feedback.

Overall Impression: What did you think about the workbook?

Volume of Information: Did **Brantford Power** provide too much information, not enough, or just the right amount?

Content Covered: Was there any content missing that you would have liked to have seen included?

Outstanding Questions: Is there anything that you would still like answered?

Suggestions for Future Consultations: How would you prefer to participate in these consultations?

Customer Consultation Report

2017 Rate Application Review

Prepared for:

Brantford Power Inc.
P. O. Box 308
Brantford, Ontario
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Customer Consultation Report

2017 Rate Application Review

April 25, 2016

This report has been prepared by Innovative Research Group Inc. ("INNOVATIVE") for Brantford Power Inc. ("Brantford Power").

The conclusions drawn and opinions expressed are those of the authors.

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INNOVATIVE
RESEARCH GROUP

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Introduction

About this Consultation

Innovative Research Group Inc. (INNOVATIVE) was commissioned by Brantford Power to help the utility design, collect feedback and document its customer engagement and consultation process as part of the development of Brantford Power's 2017 Rate Application Review, which incorporates both capital infrastructure and operational plans.

Brantford Power's 2017 Rate Application Review is a key element of its next distribution rate application. The outcome of this application will determine Brantford Power's electricity distribution rates for next year and will help set the pace of spending over the next 5 years.

The Ontario Energy Board's new "consumer-centric" approach to rate applications contained in the *Renewed Regulatory Framework for Electricity (RRFE)* requires Local Distribution Companies (LDCs) to demonstrate services are provided in a manner that responds to identified customer needs and preferences[1]. Distributors are required to provide an overview of customer engagement activities that they have undertaken with respect to its plans and how customer needs and preferences have been reflected in the distributor's application. This initiative sought to bring customers directly into the process of finding the right balance between cost and reliability in Brantford Power's 2017 Rate Application Review.

This process of identifying and reacting to customer needs and preferences towards Brantford Power's system plan development and execution, as it relates to rate applications, is new to all of Ontario's LDCs. There are no established practices and there are a number of options available to engage with customers. The following section explains how we approached this engagement.

Approach to Meaningful Customer Engagement

It is our experience at INNOVATIVE that engaging customers in meaningful consultation can be a challenge. The reality of most consultation processes is that they start out aiming to collect the views of the average person, but end up collecting the views of organized advocacy groups.

Many customers feel they don't know enough to contribute to a public consultation. Others fear the combative nature of some public processes or prefer not to risk offending friends and neighbours by taking positions on issues that are sometimes controversial. Moreover, many customers simply do not pay attention and remain unaware of particular consultations that they would participate in if they had have been aware.

Running a consultation on the Brantford Power's 2017 Rate Application Review has an additional challenge – customers' lack of familiarity with the distribution system; including how it is funded, regulated and the nature of its challenges. This is well documented in Ontario Energy Board research and in INNOVATIVE's own experience.

[1] OEB Renewed Regulatory Framework for Electricity Sections 2.4.2, 5.0, and 5.0.4.

Considering both the challenge of engaging a representative group of customers and the challenge of lack of knowledge, we developed a process built on five key principles:

1. Ensure all Brantford Power customers have an opportunity to be heard.
2. Use random-sampling research elements to ensure a representative sample of customers are engaged.
3. Create open voluntary processes that allow anyone who wants to be heard an opportunity to express themselves.
4. Focus on fundamental value choices. Look for questions that ask people to choose between key outcomes rather than focus on the technical questions of how to reach those outcomes.
5. Create an opportunity for the public to learn the basics of the distribution system so they can provide a more informed point of view.

Since this was the first time Brantford Power so explicitly engaged customers in the development of their distribution system planning, a specific effort was made to collect participant comments on the process itself.

Customer Consultation Overview

Based on the principles outline above, INNOVATIVE worked with Brantford Power staff to design a multifaceted customer engagement program which included a combination of qualitative and quantitative research elements. This consultation was designed to engage various rate classes and collect feedback on preferences and priorities as they relate Brantford Power's 2017 Rate Application Review.

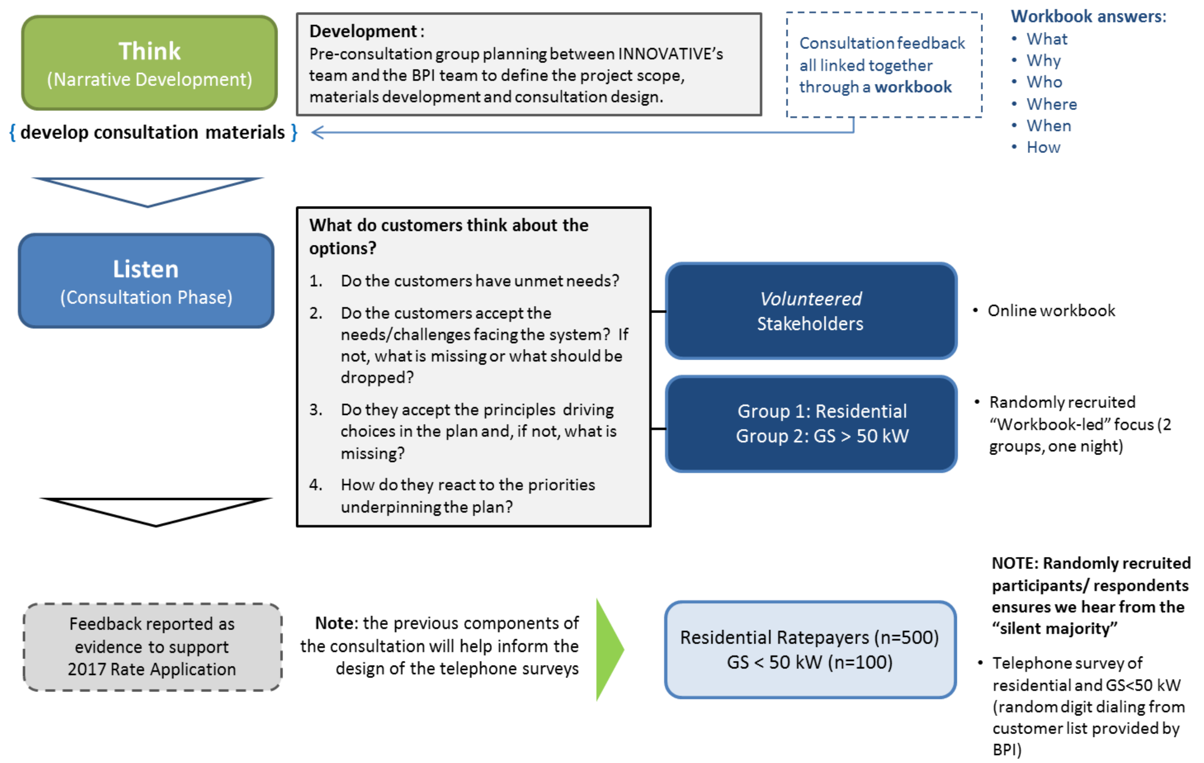
The consultation encompassed five core elements of customer engagement.

1. **General Service and Residential Consultation Groups:** This qualitative phase of the consultation was designed to educate customers, assess their preferences and priorities, gauge reaction to proposed rate changes, and ultimately inform the quantitative phases of the consultation. The groups were randomly recruited and held in Brantford. A workbook was used to provide the participants with core information about both the provincial and local electricity system, and Brantford Power's proposed capital investment and operating spend to maintain system reliability, as well as the rate impact for each respective rate class. Participants were provided incentives in recognition of their time commitment.
2. **Online Workbook**: The online workbook was promoted through print and online advertising with local print media outlets, on-bill messaging, e-billing notification emails, as well as Brantford Power's website. This phase of the consultation was available to any Brantford Power customer who wanted to participate.
3. **Random Telephone Surveys**: INNOVATIVE conducted telephone surveys with residential and general service (GS < 50kW) customers to provide a quantitative assessment of key aspects of the system plan. Customer lists for both respondent groups were provided by Brantford Power and the sample was randomly selected by INNOVATIVE.

There were three stages in developing and implementing Brantford Power's customer consultation:

- **Think**: The first stage was to develop the core background material and key questions for the workbook. INNOVATIVE and Brantford Power worked together to review the utility's system plan, capital investments and OM&A spending. Potential questions were identified that would enable customers to share their needs and preferences. Then a workbook was developed that would provide the information needed to enable customers with varying levels of knowledge to find answers to those questions.
- **Listen**: The second step was to determine the range of views held by the public regarding the system plan through the more qualitative elements of the process. This included holding two customer discussion groups using randomly recruited samples of residential and General Service customers.
- **Quantify**: The third step was quantitative – a randomly recruited telephone survey of residential and General Service customers. Randomly recruited surveys allow for generalizable conclusions that can be applied to the broader population of Brantford Power customers. The design of the surveys was in part informed based on the feedback from the qualitative research previous qualitative research components.

Customer Engagement Stages



Workbook Development

As we noted earlier, a key challenge in obtaining customer feedback on Brantford Power's rate application is the lack of knowledge customers have regarding Ontario's electricity system and Brantford Power's role as the local distributor within the system. Brantford Power's proposed distribution system plan, capital investment plan and OM&A budget are all very detailed and extensive documents that use technical language. Our challenge was to briefly cover these key issues and frame meaningful questions about customer needs and preferences.

Development of the consultation workbook began in late 2015. INNOVATIVE provided a framework for the workbook, which contained background information on the rate application process and the provincial electricity system. All content specific to Brantford Power was provided by the utility.

The final consultation workbook had five distinct chapters:

1. **What is this Consultation About?** The purpose of the section was to inform readers of where this consultation fits in the context of electricity planning in Ontario.
2. **Electricity 101**: This section described how Ontario's electricity system works and the players involved in operating and regulating the electricity system as it relates to Brantford Power's customers.
3. **Brantford Power's Distribution System Today**: This section detailed the structure and key elements of Brantford Power's distribution system.
4. **Pressures on the Distribution System**: This section described the various challenges facing Brantford Power's distribution system and provided an overview of recent and current initiatives to manage these challenges. This section also included information on cost drivers and provided an overview of both historical and forecasted capital and operating spending between 2012 and 2021.
5. **What will Brantford Power's Plan Cost Customers**: This section detailed the estimated bill impact of the plan on the average customer in the rebase year and provided forecasted bill impacts for the following four years.

Although customer experience and familiarity with the electricity sector varied, the same basic workbook was used in all qualitative customer engagements. The references to bill impact were varied to reflect the details of that specific rate class (either residential or GS less than 50 kW). As the customers went through the consultation workbook they were prompted with questions relating to system reliability, system challenges, and preferences on the direction of Brantford Power's proposed system plan, capital investment and operating spend.

Another key element of the workbook was the questions. In developing the questions, we looked for those that could also work on the telephone, without requiring all of the information in the workbook.

The *needs* questions are relatively straight-forward. We started with a basic satisfaction question and then asked an open-ended question about how Brantford Power could improve its services. We let customers discuss whatever topics they wanted to with no boundaries. Later in the workbook we probed satisfaction with the number and duration of outages and probed the impacts of those outages.

***Preferences* take a bit more effort as they require educating customers so they can make an informed trade-off between competing options; typically, between maintaining system reliability and cost implications**. Here, we were looking for value choices rather than technical issues. Key topics for preferences included:

- What should the balance be between system reliability and rate impact?
- What should Brantford Power's priority be when planning its level of investment in replacing aging infrastructure?
- How important is system modernization to customers?
- Should Brantford Power be playing a bigger role in CDM program delivery?
- Should Brantford Power invest in a new facility to house all staff and equipment?

The final substantive question asked about the cost of the plan and the outcomes it planned to achieve. Sometimes this question is asked with a simple support or opposes response scale, but we found that this type of scale does not effectively capture customer responses. Instead, we gave customers three options as well as a "don't know" option:

- The rate increase is reasonable and I support it
- I don't like it, but I think the rate increase is necessary
- The rate increase is unreasonable and I oppose it
- Don't know

The workbook concluded with a final set of five questions to assess the workbook and consultation process itself.

The workbook for residential customers can be found in the **Appendix** of this report.

Executive Summary

The following section provides the detailed findings on the needs and the preferences of Brantford Power's General Service and residential customer base. In this section, we provide a high level overview of Brantford Power customers' needs and preferences.

The overview includes feedback from customers who participated in the *qualitative stage* of the consultation where we explored the range of issues related to Brantford Power's rate application, as well as feedback from another 602 customers who responded to *quantitative* surveys where we documented the incidence of *needs* and *preferences* across the customer population.

Customer Needs & Preference

Continued delivery of high quality services

Almost all Brantford Power customers are satisfied with the job the utility is doing at running the electricity distribution system. This pattern was consistent across both residential and General Service under 50 kW rate classes in all phases of the customer consultation.

Overall Satisfaction across Consultation Activities

Q. *Thinking specifically about the services provided to you and your community by Brantford Power, overall, how satisfied are you with the services that you receive from Brantford Power?*

Response	Directional (Focus Groups)		Directional (Online Workbook)	Generalizable (Telephone Surveys)	
	General Service	Residential	Customers	General Service	Residential
Very satisfied	1	2	12	39%	45%
Somewhat satisfied	2	3	13	46%	41%
Neither satisfied nor dissatisfied	1	0	2	3%	4%
Somewhat dissatisfied	1	0	1	3%	5%
Very dissatisfied	0	0	0	5%	2%
Don't know / Refused	1	0	0	5%	3%
TOTAL	**n=6**	**n=5**	**n=28**	**n=100**	**n=502**

When we asked what Brantford Power can do better to improve services, most customers were either satisfied and had nothing to suggest or simply didn't know how the utility could improve services. However, among those who did have suggestions, comments focused almost exclusively on lowering rates.

This paradox of *lower rates* while seeking *improvements in power quality and reliability* is the key dilemma the consultation sought to explore and better understand.

Reliability of Service

The consultation focused deeper on the question of power service interruptions. In both the qualitative and quantitative phases of the consultation, information about the system's current average level of reliability was provided to customers. The consultation collected feedback on satisfaction with the current level of reliability, Brantford Power's efforts to address reliability and impact of power outages.

The qualitative consultation phases explored the impacts of outages on customers, acceptable frequencies, and duration of outages. Those findings are detailed in the following section, in the qualitative phases of the customer consultation.

The telephone surveys built on the qualitative feedback and asked questions about customer preferences on the trade-off between cost and reliability.

A majority of residential (68%) and General Service (64%) customers had experienced at least one outage in the 12 months leading up to the survey, with most outages lasting less than an hour. Asking respondents to think back to their most recent power outage:

- Well over half (64%) of residential respondents said the outage caused a *minor inconvenience*, while 27% said it caused *no inconvenience at all*. The most recent power outage was a *major inconvenience* for 8% of residential customers.
- This question was posed slightly differently to General Service customers. A third (34%) reported the most recent outage to have had a *minor cost* to their business, while 46% said it had *barely any cost, just a bit of inconvenience.* The outage had a *major cost* to 20% of businesses.

When it comes to addressing power outages, a majority of residential and General Service customers want to see spending focused on maintaining the current number and duration of outages that are experienced.

Customer preferences on addressing the <u>number</u> of power outages:

- A minority (16%) of residential customers think Brantford Power should spend what is needed to <u>reduce</u> the number of power outages, while half (50%) think they should spend what is needed to <u>maintain</u> the current level. Only 15% state that Brantford Power should accept more power outages in order to keep customer costs from rising. One-in-five (19%) *don't know* what Brantford Power should do address the number of outages.
- General Service customers respond similarly on how to address the number of outages: 15% think that Brantford Power should spend what is needed to <u>reduce</u> the number of power outages and 53% say they should spend what is needed to <u>maintain</u> the current level. Again, only a small minority (12%) believe that Brantford Power should accept more power outages in order to keep customer costs from rising. Again, one-in-five (19%) *don't know* how they feel.

Customer preferences on addressing the <u>length</u> of power outages:

- Almost seven-in-ten (68%) of residential customers think Brantford Power should spend what is needed to either reduce (14%) or maintain (52%) the length of power outages. Only

21% think that Brantford Power should accept longer power outages to help minimize customer costs from rising.

- Similarly, General Service customers think that Brantford Power should spend what is needed to reduce (19%) or maintain (57%) the length of power outages. 13% think that Brantford Power should accept longer power outages to help minimize customer costs from rising.

Capital Investment Plan

System Renewal and System Service: Survey respondents were informed of Brantford Power's proposed capital investment required to maintain system reliability and then asked to think about reliability in terms of bill impact.

- Half (50%) of residential customers and 51% General Service customers believe that Brantford Power should invest in aging infrastructure to maintain system reliability, even if it means their bills may increase.
- Over 3-in-4 customers in both groups (79% residential; 76% General Service) think the benefits of new technology are important enough to be a priority for Brantford Power.

General Plant: One of Brantford Power's major capital investments in its 2017 Rate Application is its proposed $15 million facility relocation. Throughout the consultation, customers were provided with the benefits of relocations (as perceived by the utility) and the cost implications of both a new-build option and a refurbishment option as well as the impact of maintaining the status quo of renting multiple facilities.

From the statistically significant survey, respondents provided the following feedback:

- Nearly 2-in-10 (17%) of both residential and General Service customers feel that Brantford Power should <u>build a new greenfield facility</u> that will meet their current and foreseeable future needs, while approximately 4-in-10 (43% or residential and 39% of General Service) believe Brantford Power should <u>buy an existing facility and refurbish it</u> to meet their current and foreseeable future needs.
- Those who think Brantford Power should find new rental space to house equipment and staff range between 12% among residential customers and 22% with General Service customers.

OM&A Spending Plan

An LDC's OM&A spending is largely set prior to its OEB rate application - largely by previously negotiated union labour contracts and regulated infrastructure maintenance requirements. As such, there are few areas in which the rate application consultation process can meaningfully assess customer preferences on Brantford Power's operating budget. The few areas where Brantford Power can adjust its OM&A spending, to meet customer needs and preferences, are its communications, marketing, and customer service delivery budgets.

Promoting CDM programs was one of the few concerns that surfaced in the qualitative portion of Brantford Power's customer consultation when input on OM&A was requested. In both the focus groups and the online workbook, a limited group of customers voiced concerns with how much Brantford Power was doing to help customers better manage their electricity consumption.

While commonly known within the industry, one of the most cost effective ways for a utility to reduce its required investments in the distribution system is through increasing customer uptake of conservation and demand management programs. As such, we asked a representative sample of Brantford Power customers in the telephone survey component of the consultation:

- if they have ever participated in a Brantford Power promoted CDM program;
- what their likelihood of participating in a CDM program would be in the future, and;
- how good or poor a job the utility is doing at promoting CDM programs.

Here is what Brantford Power customers said about Brantford Power's CDM programming and communications efforts.

- A majority of Brantford Power customers do <u>not</u> participant in CDM programs. Roughly 4-in-10 customers (41% residential and 36% General Service customers) believe they currently or have in the past participated in conservation programs;
- When asked, a majority of customers say they would participate in conservation programs that would help them to reduce their electricity consumption (74% residential and 73% General Service).
- Customers were asked to rate how well a job Brantford Power is doing at providing information on available tools and programs that can help manage customer electricity consumption.

  Among residential customers, 8-in-10 (81%) feel that a good job is being done, while only 14% feel that the utility is doing a poor job.

  General Service customers feel less informed than residential customers. Only 64% of General Service customers feel that Brantford Power is doing a good job of providing their businesses with information on available tools and programs that can help them better manage electricity consumption. Three-in-ten (28%) General Service customers feel the utility is doing a poor job at providing their businesses with information on CDM.

Customer Reaction to Proposed Rate Increase

Social Acceptance of a Rate Increase

Asking customers whether they support or oppose a rate increase puts many participants in a difficult spot. It is clear that many customers have an issue with the idea of "supporting" a rate increase. While they do not want or like a rate increase, they are often not opposed to a rate increase. In fact, many feel a rate increase is needed. As such, we created a response for these customers: "I don't like it, but I think the rate increase is necessary".

Other participants had no problem in expressing outright support for a rate increase. The statement we provided for them is "The rate increase is reasonable and I support it".

When we refer to the combination of these two groups – I don't like it but it's necessary and I support the rate increase – we refer to the level of "**social acceptance**".

Referring to the generalizable results from the telephone surveys, 65% of residential customers accept Brantford Power's proposed rate increase, while 68% of General Service customers accept the proposed rate increase.

Q: Considering the cost of Brantford Power's proposed plan, would you say …

Response	Directional (Focus Groups)		Directional (Online Workbook)	Generalizable (Telephone Surveys)	
	General Service	Residential	Customers	General Service	Residential
The rate increase is reasonable and I support it	-	3	6	20%	28%
I don't like it, but I think the rate increase is necessary	4	2	12	48%	37%
The rate increase is unreasonable and I oppose it	2	-	8	27%	29%
Don't know / Refused	-	-	2	4%	6%
Social Permission	**4/6**	**5/5**	**18/28**	**68%**	**65%**
TOTAL	**n=6**	**n=5**	**n=28**	**n=100**	**n=502**

Impact on Vulnerable Customers

A majority of the most financially vulnerably customers provide social permission on Brantford Power's proposed rate increase.

As commonly observed[2] in many Ontario communities, a majority of Brantford Power customers feel a "financial pinch" when it comes to the current impact of their electricity bills. When asked if electricity bills have a material impact on household or business finances, a majority of customers agree that the cost of their electricity bill has a major impact on their finances and requires them to do without other important priorities or business investments.

- 55% of residential customers agree that "*The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities*";
- While 67% of GS customers agree that "*The cost of my electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.*"

Customers accept the proposed spending and investment plan presented by Brantford Power and its accompanying rate increase as an unfortunate necessity of maintain system reliability as seen throughout Brantford Power's customer consultation, there is no simple answer to electricity utility spending and investing from the customer's perspective. Rate increases are undesirable, but lower reliability is clearly unacceptable and a prudent yet proactive approach to system maintenance appears to be understood and accepted by customers.

[2] Source: Innovative Research Group; publicly reported OEB Rate Applications; customer consultations under the RRFE framework.

Focus Group Consultation

Summary

General Satisfaction:

General Service participants reported varying levels of satisfaction with the service they receive from Brantford Power ranging from *very satisfied* to *somewhat dissatisfied*. Generally, their satisfaction was directly related to their experience with, and the severity of impact of, power quality issues such as blips and surges. Residential customers rate their satisfaction highly; all reported that they were at least *somewhat satisfied*.

System Reliability:

General Service participants have a wide array of experiences in regards to reliability. These participants were more concerned with brief power interruptions than longer outages. Depending on the type of business, the smallest power interruption could result in short losses of productivity, or in a manufacturing setting, thousands of dollars worth of damages, hours of lost productivity, and potential safety concerns. No General Service participant felt an outage lasting more than one hour was reasonable.

Residential participants had no complaints about the reliability of the service they receive. Many could not recall a recent outage lasting any length of time. They also acknowledged that certain interruptions, such as accidental damage to a pole, are beyond Brantford Power's control, and they accept them as only a minor inconvenience. Further, all but one participant would be willing to pay more to maintain the current level of reliability.

Facility Relocation:

Overall, General Service participants prefer exploring existing facility alternatives over building a new facility. Having everything under one roof was not deemed to be necessary. Renting was seen positively from an operational perspective, and one participant felt that supporting local landlords would equate to contributing back to the community.

Residential participants were divided between building a new facility and exploring the more cost effective option. Those in support of a new building noted the efficiencies of having everything under one roof, and the benefits of designing a facility to meet Brantford Power's exact needs. They acknowledged that Brantford Power provides an essential service, and the cost implications were not deemed to be too severe. Others found either option to be acceptable provided that the plan is the most cost effective, and current and future needs are guaranteed to be met.

Social Acceptance of Plan:

Almost every participant in both groups felt that Brantford Power's proposed plan is going in the *right direction*, with the exception of two participants from the General Service group who *didn't know*. The majority of participants don't like the idea of an increase but understand its necessity. Three participants from the Residential group supported the increase outright, while two General Service participants opposed it.

In both groups, there was an understanding of the costs involved in maintaining the system into the future, particularly given the amount of growth on the City of Brantford's horizon. The amount of the increase was generally seen to be nominal and reasonable.

The following table illustrates these findings.

Q: Considering what you know about the local distribution system, which of the following best represents your point of view?

Response	GS	RS	COMBINED
The rate increase is reasonable and I support it	0	3	3
I don't like it, but I think the rate increase is necessary	4	2	6
The rate increase is unseasonable and I oppose it	2	0	2
Don't know	0	0	0
Total	6	5	11

Note: "GS" = general service less than 50 kW customers, while "RS" = residential customers.

Methodology

About the General Service and Residential Customer Consultation

INNOVATIVE was engaged by Brantford Power to conduct General Service and Residential customer consultation sessions designed to identify the needs and preferences of customers as they relate to the utility's proposed spending on the distribution system.

The consultation sessions were held in Brantford on February 8th, 2016. A total of 11 General Service and Residential customers participated in these consultation sessions.

General Service under 50 kW Rate Class	6 participants
Residential Rate Class	5 participants

Recruiting Consultation Participants

General Service customers in the under 50 kW rate class were randomly selected from customer lists and then screened by telephone for appropriateness as session participants. These customers qualified for the consultation if they manage or oversee their business' electricity bill. This was to ensure that they were at least somewhat knowledgeable of their electricity costs and could have an informed discussion on the impact of the proposed rate increase.

Residential customers were screened to ensure they are the person in the household that has primary or shared responsibility for paying the electricity bill.

All customer lists were provided to INNOVATIVE by Brantford Power.

An honorarium of $100 was provided to all General Service and $80 to all Residential customers who participated in the consultation sessions.

All consultation sessions were video recorded to verify participant feedback and verbatim quotes.

Consultation Session Structure

The consultation sessions were structured around the themes contained in the workbook that was developed by INNOVATIVE and Brantford Power staff in early February 2016.

The workbook themes included the following:

1. What is this Consultation About?
2. Electricity 101
3. Brantford Power's Distribution System Today
4. Pressures on the Distribution System
5. What the Plan Means for You

At the start of the sessions, the facilitator gave an overview explaining the purpose of the consultation and why Brantford Power is seeking feedback from General Service and Residential customers. No Brantford Power employees were present in the room during the focus groups.

After explaining the purpose of the consultation, hardcopy workbooks were distributed to act as a session guide and for participants to record their answers to the questions contained within.

The facilitator then led the participants through the workbook section by section to ensure they understood the information and to answer any questions about the content.

When it came to the questions within the workbook, participants were asked to fill in their answers independently. The facilitator then led a group discussion on the answers participants provided and what the various issues meant for them or their businesses.

While the consultation was largely based on this structure, group discussions arose naturally as participants explored the workbook. Questions and comments were addressed by the moderator, and depending on the topic (i.e. whether or not it fell within the scope of this consultation), participants' impressions were further probed.

Hardcopy workbooks were collected from the participants at the conclusion of each consultation session.

Each consultation session ran for approximately 2 hours.

Informing the Consultation Process

In addition to identifying customer needs and preferences as they relate to the proposed distribution system plan, feedback collected from this phase of the consultation was used to inform the design of the online and telephone survey consultation phases of Brantford Power's customer engagement program.

NOTE: Results contained within this report are based on a limited sample and should be interpreted as directional only. **This is not a statistically significant poll.**

Participant Feedback

The following sections highlight the general feedback from each consultation group.

General Service under 50 kW Rate Class

To put this consultation in context, the participants were first brought up to speed about the electricity system as a whole, and introduced to the various means by which consumer feedback is collected. They were introduced to Ontario's Long Term Energy Plan, Regional Planning undertaken by the IESO, and informed that this consultation would be centred on Distribution Planning.

This section also provided the moderator the opportunity to educate participants on how the electricity system is regulated. One participant noted that Brantford Power was a monopoly and that customers are at the mercy of the distributor when it comes to setting rates. The moderator responded to this with a brief explanation of the OEB and its responsibilities. Further, it was noted that this consultation is in fact part of the evidence Brantford Power must submit to the OEB as part of its rate application process.

It came as a surprise to many that Brantford Power's portion of their electricity bill only accounts for 17% of their total bill, and that there are many other aspects to which their bill is allocated. The explanation of this gave perspective to several of the participants.

> *That's what I never knew – why hydro is still expensive even when I'm not using it. Now when you explain all these parts, I understand where it's coming form.*

They were also introduced for the first time to the proposed rate increase that Brantford Power is projecting, and where Brantford Power envisions their rates to be in 2021.

After further exploration of the electricity system as a whole, and the assets and services Brantford Power is responsible for, participants were asked about their familiarity with the various parts of the electricity system. None of the participants felt that they were *very familiar and could explain the details of Ontario's electricity system to others,* while three of the participants felt they were *somewhat familiar, but could **not** explain all the details.*

Following the introductory section however, almost all participants felt that given what they had read thus far, Ontario's electricity system had been explained to them *very well* – only one participant indicated *somewhat well*.

General Satisfaction

General Service customers have experiences with the Distribution System as varied as their businesses. While none of the participants indicated they were *very dissatisfied*, their responses covered the rest of the spectrum – one respondent was *very satisfied* and two were *somewhat satisfied*. Satisfaction was rated from a power quality perspective. That is, participants whose businesses are most affected by surges and power quality issues, reported the least satisfaction. This will be discussed further in the coming sections of this report.

System Reliability

In terms of outages, General Service customers had varied experiences with reliability. In the last year, three of six had experienced only one outage; and one participant had experienced each of three, two, and zero outages. Before responding, the question was asked what constituted an outage, and the moderator clarified that an outage is characterized by a power interruption lasting longer than one minute. Outages as defined did not seem to be a serious concern as half the group felt two outages a year is reasonable, while the other half felt that one is reasonable. Further, in terms of duration of outages the group was divided in feeling that outages lasting less than 15 minutes, to less than an hour are appropriate.

> *I've had at least three. Last summer, it went down and came back on, and then you think everything's giggles again, but then it went down again. And that's hours [of lost productivity]. I wouldn't accept more outages.*

Participants were divided in terms of the balancing act between reliability and the cost of running the system. One participant *would be willing to accept more and longer power outages if that meant there would be a decrease to their distribution rates*; while two participants *would be willing to pay a bit more to maintain the current level of reliability.* The remaining participants, however, either *didn't know* or left this question blank. Being of a business mindset, they had difficulty choosing one option without more specific information. There was some acknowledgment that investing in the system could benefit over the long-term, but without more detailed figures participants found it difficult to say.

> *I don't want a higher bill, but I don't want more outages either.*

> *I think what makes that question unfair is that there are no numbers. If it's say, $1 a month then okay no problem, but if you're going to double it, I don't know if that's worth it. It's a cost benefit thing. It's like the ice storm. It cost a pile to put that extra good stuff in but what was the cost of down time when you couldn't work for three days or more. So you save that and it's worth having spent the extra money. It's an investment over a long period.*

Impact of Outages

The impact of outages to General Service customers varies depending on their daily operations, however there was consensus that power quality issues impact their businesses. In an office setting, blips result in network connectivity issues, and involve restarting the system and potentially losing some work. This led one participant to outfit their office with surge protectors.

> *The other day there was a power surge and we had to do the whole reboot.*

> *Maybe it's the area. We're on Henry St. The computers shut down so we've gone and got the power surge battery backup. It's not a monthly basis, but it happens enough that we've had to do something about it. It's on the back end of an industrial area so maybe that's why.*

In a more industrial setting the consequences of power quality issues are more severe. When systems are interrupted, safety protocols come into effect and it can take hours to have production back up and running. Further, there is always risk of damage to the product or equipment. One participant noted that some of his equipment has electric magnet safety features that are disabled by blips, and interruptions pose a serious safety concern.

> *We're over on Elgin and experience the same thing. It's a real kick in the teeth. It'll set you back a half hour. You got six or eight guys, you know, that's four hours. If it browns out for a second everything shuts down. You gotta reset the whole process and you might have to replace broken or damaged tools.*

Additionally, if the power is out for a longer duration it becomes an issue of lost productivity. Management has to make the decision whether to shut down operations for the day, or wait for the power to come back on.

> *If it's down for a couple hours at a time, during the afternoon, how long do we stick around and wait for this to come back on?*

Improving Service of the Local Distribution System

Aside from addressing power quality issues, participants had only minor suggestions for improving the system. One participant mentioned wanting access to his meter while another preferred when water and hydro was on the same bill.

> *I don't think there is [a way to improve service]. The only thing is that the meter is locked up. I'd like to be able to look at it and make sure what they're charging is correct.*
>
> *It was a pain when they removed the water and hydro. Now I get several bills. That's a royal pain.*

Facility Relocation

The overarching concern regarding facility relocation is for Brantford Power to have a strong business case. While there was debate over the specific course of action, the need for Brantford Power to do their due diligence was constant.

Some participants didn't feel concrete in their understanding of the steps Brantford Power was taking to ensure that the relocation plan is as informed as possible. They wanted to make sure outside consultants had been hired, a cost-benefit analysis had been done, and all options had been explored. Half either said don't know or didn't answer the question in the workbook.

> *They need to engage other services and analysis. Do more research and make sure this is well informed.*
>
> *These guys are in the business of giving us hydro. They're not in the building business and they are not in the real estate business. What Brantford Power should do is engage someone. They've got to do some consultation.*

Participants in support of renting or refurbishing were most vocal in their views. They saw the value of renting in terms of savings, efficiencies and contributing back to the community. One participant felt that there were no real efficiencies to be had in a one-building facility. Comments from three individual participants are highlighted below.

> *If they're renting they're also helping other people, like landlords. So their money is going back into the system and helping out other businesses. Whereas, to build a new facility, there's no cheap way of doing that. And there are so many existing facilities – to me it's either between renting or taking an existing facility and fixing it up to meet their needs.*
>
> *I have a problem with non-for-profits owning a facility. Especially companies like this that don't have a capital reserve – Why not rent the place? It goes into your operating costs, you know what it is year after year after year. You go building a new facility, spending millions of dollars, then you've still got to operate it.*
>
> *I think it's far more fiscally responsible to buy a facility and refurbish it. Also "all under one roof?" – Why does the billing department have to be at the truck repair facility? They got nothing to do with each other.*

Only one participant was in favour of building a new facility that will meet Brantford Power's current and foreseeable future needs.

> *There's efficiency to be had in one building facilities.*

Capital Investment and Operating Budget

Participants were asked to comment on the balancing act between reliability and the cost of running the system. Only one participant was willing to accept more and longer power outages in order to keep the cost of their bills from rising. Three participants however were dissatisfied with the choices they were given and either indicated *don't know* or refused to answer.

Regarding vehicles, tools and IT systems, all participants who answered the question felt that while Brantford Power should be wise with its spending, it is important that its staff have the equipment and tools they need to manage the system efficiently and reliably.

In terms of projects focusing on replacing aging equipment, three participants did not feel they had sufficient information to give an opinion. These participants wanted more detailed information about the costs involved with replacing such equipment, and Brantford Power's concrete plan for managing these costs. Of those who did answer, one participant felt that *Brantford Power should invest what it takes to replace the system's aging infrastructure to maintain system reliability, even if that increases their monthly electricity bill by a few dollars over the next few years.* Two participants would rather see Brantford Power *lower its investment in renewing the system's aging infrastructure to lessen the impact of any bill increase, even if that means more or longer power outages.*

One participant in favour of investing what it takes, was of the opinion that proactive maintenance is more cost efficient, and a better idea in the long-term.

> *Biggest thing is preventative. It costs more to fix it after so it's easier to maintain things.*

Cost Drivers

Upon reading the section on cost drivers, all participants felt they understood at least somewhat well the cost drivers that Brantford Power is responding to (2 *very well;* 4 *somewhat well*).

In terms of managing these cost drivers, four participants felt that Brantford Power is doing a good job, and only one felt that they are doing a poor job. When asked how Brantford Power could manage these drivers more effectively, this group offered few suggestions for areas they deemed in need of improvement. Yet, there was some suggestion that field staff could be managed more effectively.

> *They need to manage the team on job sites more efficiently.*

Further, when asked how satisfied they are with the efforts Brantford Power has made to find efficiencies and cost savings in the distribution system, the majority of participants are *somewhat satisfied.*

Proposed Plan and Rate Impact

Overall, participants felt that Brantford Power is going in the right direction, and the process of consultation was appreciated.

> *I think this kind of thing is good, to get feedback. I think they're doing their due diligence.*

In terms of the rate increase, only two participants were in opposition. Most participants don't like the idea of an increase but acknowledged that it is necessary to maintain the system.

> *We never like anything going up. When I gather my ten bills it's not much fun to look at. But common sense tells me that if you want something to run right, you have to invest. The amount doesn't seem like a great deal [of money], so I don't think it will break any of us. We never like to see anything go up, but the future always goes up. If it has to go up, it has to go up.*

Residential Rate Class

Prior to the consultation, familiarity with Ontario's electricity system was relatively low; three participants were *somewhat familiar*, while the others reported a lower level of familiarity. After reading through the introductory section however, all participants felt that Ontario's electricity system had been explained to them at least *somewhat well*.

General Satisfaction

General satisfaction among residential participants is quite high. Three participants indicated in the workbook that they were *somewhat satisfied* with the service that they receive, while two were *very satisfied*. There was not a complaint to be heard by these participants.

> *The lights come on when I flip the switch. I'm pretty happy.*

Improving Service of the Local Distribution System

When asked how the system could be improved, participants had no major concerns or suggestions. The discussion turned to how reliable the service is, and how infrequent power outages are. When the power does go out the impact is minimal and power is restored very quickly.

> *No, I'm pleased with the service.*
>
> *I live in an older part of town and it's usually pretty good. When someone smokes a hydro pole it's not the hydro's fault. It's usually back on pretty quick.*
>
> *We had a squirrel short himself out and shut the neighbourhood down, but that was no big deal.*

System Reliability

In terms of system reliability, residential participants are also quite happy; almost all (4) had experienced zero outages in the year prior.

> *I can't even think of the last time it went out for any substantial time.*
>
> *My hydro flickered off last week and it was back on instantly.*
>
> *When they ask if you're happy with the service and the reliability – I've never really thought about it because the electricity has always been there. With only several exceptions, like the ice storm.*

Some did experience very brief interruptions, but they were not deemed a concern, as all but one participant indicated that outages lasting between one and two hours to be reasonable. However in the discussion, participants gave a much more lenient timeline before an outage becomes an inconvenience.

> *To me it's an outage if it's inconvenient – after several hours. Five hours would be a problem.*
>
> *I think if it went off for more than twelve hours we'd be upset, but it's never been off that long.*

Four of the five participants would be willing to pay a bit more to maintain the current level of reliability. There was acknowledgment that the cost of managing such a system is apt to rise over time, and that this is to be expected. This sentiment was particularly strong for one participant with young children at home.

> *I would pay more to maintain the current level of reliability. Things cost more every year. Costs go up; everyone understands that.*

If the power goes out my life's a-stoppin'; I have to go to a motel. I would pay more to improve reliability. I've got young kids in the house and it's inconvenient for me – especially being a single mom on low income. I have very low income in my house but I would still sacrifice for a reliable system.

Customer Experience and Expectation

None of the participants had ever found it necessary to contact Brantford Power for any reason. The discussion turned again to their level of satisfaction with the system reliability and how quickly power is restored in the event of an outage. One participant appreciated the outreach they received from customer service.

I don't think I've ever called them. If it was as unreliable as my internet, I'd be on the phone with them all the time, but I've never had an issue with hydro.

The only time I can recall is when a transformer was shorted out by a racoon. The power was back on in maybe an hour. It was sort of unreal how fast it was – that they could get the equipment and switch it out.

I got a call at work saying that my power was off, then "Oh it's back on never mind." Just the call was nice.

Facility Relocation

When asked how Brantford Power should manage the relocation of its facilities, participants were divided between building a new facility and exploring the most cost effective option, whichever that may be. The efficiency of housing all operations in one location and the ability to ensure the facility is tailored to Brantford Power's exact needs are important to those who support building a new facility.

It makes more sense to have it all under one roof.

I would say build one, because when you get into refurbishing something and trying to make it meet your needs, sometimes that can turn out to be more expensive than starting out with a blank slate and building what you know are your needs.

For these participants, the cost of building a new facility is not a deterrent to maintaining a necessary service.

I agree [with building a new facility]. You know you're going to depreciate over 50 years. It's an essential service, you need the best of everything.

$15.4 million over 50 years. It's not like we're going to get slammed with it over the next couple years. It's balanced out.

Despite two participants having indicated in the workbook that Brantford Power should buy an existing facility and refurbish it, this option did not come up in the discussion. Rather, there was agreement that the most cost effective solution would be the most appropriate (a response option that was not provided in the workbook). While one participant had some initial trepidation, it was agreed that as long as the facility would be able to meet current and future needs, either option is viable.

It would depend on what you need in terms of renovating an existing building. I don't know what their particular needs might be and how unique their needs might be. I don't know if they'd be able to move into a building and renovate it to meet their needs. Not knowing that, frankly I don't know which to choose.

Either as long as it meets their needs and as long as in ten years they don't go, "Oh, we need another new facility."

Go with the more cost efficient solution, whichever it might be.

Capital Investment and Operating Budget

When it comes to investing in vehicles, tools, and IT systems, participants unanimously felt that *while Brantford Power should be wise with its spending it is important that its staff have the equipment and tools they need to manage the system efficiently.* They acknowledge that time is money, and having the proper resources is necessary to effectively managing the system.

Working for the municipality, I know what it's like to have stuff that breaks every single day. You're constantly fixing – that's downtime. It's costing you more in the long run. In the long run it's more efficient.

You mentioned before, when it comes to finding a break they don't have to drive up and down three blocks looking for it. The crew knows where it is before they leave the depot and can go right to it.

Further, participants also unanimously agreed that *Brantford Power should invest what it takes to replace the system's aging infrastructure to maintain system reliability, even if that increases their monthly electricity bills by a few dollars over the next few years.*

Cost Drivers and Finding Efficiencies

After reviewing the workbook section on cost drivers and finding efficiencies, almost all participants felt they understood the cost drivers Brantford Power is responding to at least *somewhat well* – two felt they understood *very well*, while one *didn't know.* Similarly, all participants except one who *didn't know* felt that Brantford Power is doing at least a *good* job of managing these drivers.

None of the participants felt that any of the expenditures outlined in the workbook were unreasonable, and almost all felt at least *somewhat satisfied* with the efforts Brantford Power has made to find efficiencies and cost savings in the distribution system.

Proposed Plan and Rate Impact

After reviewing the workbook in its entirety, every participant indicated that they feel Brantford Power's investment plan seems to be going in the right direction. Further, they positively rated the job Brantford Power is doing when it comes to planning for the future (3 *good;* 2 *very good*).

In regards to the proposed rate increase, none of the participants were in opposition. Two participants didn't like the idea of a rate increase but acknowledged that it is necessary; the rest supported the increase outright.

Those who didn't like the increase but felt it necessary cited the growing community as a reasonable justification of the increase, in addition to the aging infrastructure.

Who wants to pay more money? But I understand where it's coming from and it's manageable.

The community is growing so a small increased rate is understandable. Plus cost of living across the board goes up.

I think it's unavoidable. The aging infrastructure and Brantford's population growth will put more pressure on the system. So it's unavoidable really.

There is acknowledgment of rising costs and the necessity of reliable equipment among those who fully support the increase. For these participants, a well-managed and dependable system is paramount, and an increase in their monthly bills to achieve this is well worth it. One participant was even pleasantly surprised with the nominal increase.

> *It is reasonable to expect a modest nominal increase due to rising fixed costs, and impending capital expense needs.*
>
> *To get reliable power we would need reliable equipment and upgrading costs money*
>
> *I believe that it is reasonable, and I want a utility that provides dependable service.*
>
> *I was actually surprised. Maybe it was electioneering or what have you but I was thinking we had these massive increase in rates coming but this doesn't seem like an outrageous amount.*

How Could the Consultation Process be Improved?

Overall, the participants felt the consultation process was well thought out and informative. The information provided was comprehensive, easily understood, and informative. They also appreciated the opportunity to provide feedback in a meaningful way. No one had suggestions on how to improve the process.

> *I think it was easy reading.*
>
> *It was easy for a lay person to understand. It was well laid out.*
>
> *It was a good amount of information. You didn't hand us a book that was too thick and full of technical terms.*
>
> *I think they should continue doing it. It makes you think, as residents, that they value your opinion.*

Questionnaire Results (Workbook)

The following tables are the tabulations of participant feedback to questions in the workbooks, which were returned at the end of each consultation session.

Note: “GS” = general service less than 50 kW customers, while “RS” = residential customers.

1. Before this consultation, how familiar were you with the various parts of the electricity system, how they work together, and which services Brantford Power is responsible for?

	GS	RS	TOTAL
Very familiar and could explain the detail of Ontario's electricity system to others	-	-	-
Somewhat familiar, but could not explain all the details of Ontario's electricity system to others	3	3	6
Have heard of some of the terms and organizations mentioned in this workbook, but knew very little about Ontario’s electricity system	2	1	3
Aside from receiving a bill from Brantford Power, I knew nothing about Ontario’s electricity system	1	1	2
TOTAL	6	5	11

2. Given what have read so far, how well do your feel Ontario’s electricity system has been explained to you?

	GS	RS	TOTAL
Very well	5	3	8
Somewhat well	1	2	3
Not very well	-	-	-
Not well at all	-	-	-
Don't know	-	-	-
TOTAL	6	5	11

3. Generally, how satisfied are you with the service you receive from Brantford Power?

	GS	RS	TOTAL
Very satisfied	1	2	3
Somewhat satisfied	2	3	5
Neither satisfied nor dissatisfied	1	-	1
Somewhat dissatisfied	1	-	1
Very dissatisfied	-	-	-
Don't know	1	-	1
TOTAL	6	5	11

5. In 2015, the average Brantford Power customer experienced one power outage per year. Do you recall how many outages you experienced in the past year?

	GS	RS	TOTAL
None	1	4	5
One	3	1	4
Two	1	-	1
Three	1	-	1
Four	-	-	-
More than four	-	-	-
Don’t know	-	-	-
TOTAL	6	5	11

6. How many power outages do you feel are reasonable in a year?

	GS	RS	TOTAL
No outage is acceptable	-	-	-
One	3	2	5
Two	3	3	6
Three	-	-	-
Four	-	-	-
Five or more	-	-	-
Don't know	-	-	-
TOTAL	6	5	11

7. What do you feel is a reasonable duration for a power outage?

	GS	RS	TOTAL
No outage is acceptable	-	-	-
Less than 15 minutes	2	1	3
15 to less than 3- minutes	2	-	2
3- minutes to less than 1 hour	2	-	2
1 hour to less than 2 hours	-	4	4
2 hours or more	-	-	-
Don’t know	-	-	-
TOTAL	6	5	11

8. No distribution system can deliver perfectly reliable electricity service. There is a balancing act between reliability and the cost of running the system. Please select what statement comes closest to your point of view.

	GS	RS	TOTAL
I would be willing to accept more and longer power outages if that meant there would be a decrease to my distribution rates on my electricity bill	1	-	1
I would be willing to pay a bit more on my distribution rates to maintain the current level of reliability	2	4	6
I would be willing to pay much more on my distribution rates to improve the level of reliability I currently receive from Brantford Power	-	-	-
Don't know	1	1	2
Missing Value	2	-	2
TOTAL	6	5	11

9. In terms of Brantford Power's facility relocation, what option do you think your utility should pursue?

	GS	RS	TOTAL
Build a new facility that will meet their current and foreseeable future needs	1	3	4
Buy an existing facility and refurbish it to meet their current and foreseeable future needs.	2	2	4
Stick with the status quo and find new rental space to house equipment and staff	-	-	-
Something else	-	-	-
Don't know	1	-	1
Missing value	2	-	2
TOTAL	6	5	11

11. As a company, Brantford Power needs vehicles and tools to service the power lines and IT systems to manage the system and customer information. Which of the following statements best represents you point of view?

	GS	RS	TOTAL
Brantford Power should find ways to make do with the equipment and IT systems it already has.	-	-	-
While Brantford Power should be wise with its spending, it is important that its staff have the equipment and tools they need to manage the system efficiently and reliably.	4	5	9
Don't know	-	-	-
Missing value	2	-	2
TOTAL	6	5	11

12. With regards to projects focused on replacing aging equipment in poor condition, which of the following statements best represents your point of view?

	GS	RS	TOTAL
Brantford Power should invest what it takes to replace the system's aging infrastructure to maintain system reliability, even if that increases my monthly electricity bill by a few dollars over the next few years.	2	5	7
Brantford Power should lower its investment in renewing the system's aging infrastructure to lessen the impact of any bill increase, even if that means more or longer power outages.	1	-	1
Don't know	-	-	-
Missing value	3	-	3
TOTAL	6	5	11

14. How well do you feel you understand the cost drivers that Brantford Power is responding to?

	GS	RS	TOTAL
Very well	2	2	4
Somewhat well	4	2	6
Not very well	-	-	-
Not well at all	-	-	-
Don't know	-	1	1
TOTAL	6	5	11

15. How would you rate the job Brantford Power is doing to manage these cost drivers?

	GS	RS	TOTAL
Very good	-	2	2
Good	4	2	6
Poor	1	-	1
Very poor	-	-	-
Don't know	1	1	2
TOTAL	6	5	11

17. How satisfied are you with the efforts Brantford Power has made to find efficiencies and cost savings in the distribution system?

	GS	RS	TOTAL
Very satisfied	-	2	2
Somewhat satisfied	4	2	6
Not very satisfied	-	-	-
Not at all satisfied	-	-	-
Don't know	2	-	2
Missing value	-	1	1
TOTAL	6	5	11

19. From what you have read here and what you may have heard elsewhere, does Brantford Power's investment plan seem like it is going in the right direction or the wrong direction?

	GS	RS	TOTAL
Right direction	4	5	9
Wrong direction	-	-	-
Don't know	2	-	2
TOTAL	6	5	11

2-. How would you rate the job Brantford Power is doing when it comes to planning for the future?

	GS	RS	TOTAL
Very good	-	2	2
Good	5	3	8
Poor	1	-	1
Very poor	-	-	-
Don't know	-	-	-
TOTAL	6	5	11

21. Considering what you know about the local distribution system, which of the following best represents your point of view?

	GS	RS	TOTAL
The rate increase is reasonable and I support it	-	3	3
I don’t like it but I think the rate increase is necessary	4	2	6
The rate increase is unreasonable and I oppose it	2	-	2
Don’t know	-	-	-
TOTAL	6	5	11

Online Workbook

Summary

Most of the 28 workbook respondents think favourably on Brantford Power's brand, its infrastructure plans and the proposed rate increase.

Respondents claim to understand the system and are satisfied with their service.

- Most of the 28 respondents surveyed are familiar (19/28) with Brantford Power's role and all respondents felt the system was explained well.
- Almost all (25/28) of the customers surveyed are satisfied with their service. When asked for suggested improvements, respondents brought up improved communication with its customers, system reliability and reduced costs.

Respondents likely to pay more for reliability.

- Nearly half (13/28) of customers would be willing to pay a bit more to improve reliability but only five of the 28 respondents would pay "much more" to improve reliability.
- Most Brantford Power customers experienced one outage or less and most of the customers (18) felt that 1or 2 outages were a reasonable number per year.
- A slight plurality (13/28) thought a reasonable duration for an outage would be "30 minutes or less".

"Refurbish, don't build" and invest in aging infrastructure despite costs.

- Almost half (12) of respondents think Brantford Power should buy and refurbish an existing facility. Seven respondents think Brantford Power should build a new facility and six prefer to stick with the status quo and find new rental space for equipment and staff.
- Most (21/28) workbook respondents think Brantford Power should invest in equipment and tools to manage the system while just seven thought it should make do with the status quo.
- In weighing investment versus cost, half (14/28) of respondents think Brantford Power should invest in its aging infrastructure despite bill increases whereas 11 respondents think it should reduce its investment to keep bills lower.

Respondents self-report a good understanding of cost drivers, support Brantford Power's efforts to find efficiencies.

- All respondents report they understand the cost drivers facing Brantford Power and a strong majority (22/28) think it's doing a good job to manage these costs.
- Three-in-four (21/28) respondents are satisfied with Brantford Power's efforts to find efficiencies in the distribution system.

Permission granted among respondents, investment plan "headed in right direction".

- Most (18/28) of respondents feel that Brantford Power's investment plan is on the right track and that Brantford Power is doing a good job planning for the future (19/28).
- A majority of respondents (18/28) accept the proposed rate increase. Just eight respondents out of 28 would oppose it.

NOTE: This is not a statistically significant poll. Results contained within this report are based on a non-representative, volunteer sample and are intended for exploratory research only.

Graphs and tables may not always total 100% due to rounding values rather than any error in data. In addition, sums are added before rounding numbers.

Methodology

A Background on the Online Workbook

INNOVATIVE collected participant feedback on behalf of Brantford Power in the form of an online workbook. Before each section of questions, customers reviewed a series of audiovisual materials that included links to informative videos. In total, customers answered 22 core questions as well as five feedback questions about the survey itself.

The Brantford Power Workbook divided into five key sections:

- "What is this Consultation About?"
- "Electricity 101"
- "Brantford Power's Distribution System Today"
- "Pressures on the Distribution System"
- "What will Brantford Power's Plan Cost Customers?"

The first section "What is this Consultation About?" explains how Brantford Power is collecting feedback on its 2017 to 2021 investment and spending plan. It outlines the consultation process, customer billing, how the rate application process works and also how critical customer feedback is to informing Brantford Power's rate application and distribution plan. This section is purely descriptive, designed as background for the customer and includes no questions.

The second section "Electricity 101" explains Brantford Power's role in Ontario's electricity system as a distributor as well as a broad overview of how Brantford Power manages its assets. Baseline questions on system familiarity and satisfaction are included as well as a follow-up question on suggested improvements.

The third section "Brantford Power's Distribution System Today" outlines Brantford Power's record on system reliability and explains the operating and capital expenditures involved in local distribution. Respondents are asked questions on expected and actual length and frequency of outages and attitudes on cost vs. reliability.

"Pressures on the Distribution System", the fourth section in the online workbook, examines the key pressures on the distribution system and how Brantford Power manages its capital investment based on cost drivers such as reliability, service requests, support capacity delivery, system efficiency, mandated compliance, obsolescence, aging equipment and business support costs. In addition, Brantford Power outlines its current facility challenges and outlines the costs and benefits of constructing new facilities versus acquiring and renovating existing facilities. Questions in this section focus on attitudes regarding infrastructure repair and facility relocation.

The final section “What Will Brantford Power’s Plan Cost Customers?” outlines the bill impact for residential and business customers of its increased distribution rates. Questions in this section include perceptions of Brantford Power’s investment plan and the “permission question”: whether or not customers will support or oppose the proposed rate increase.

Throughout each section, Brantford Power has included additional open-ended questions to probe customers, digging deeper on key issues such as customer satisfaction, perceptions of the current investment strategy and rate permission.

Additional questions at the end ask specific feedback on the survey itself relating to overall impression, breadth and depth of information covered in the workbook and suggestions for future consultations.

Field Dates:

The workbook was accessible online for Brantford Power customers from February 24, 2016 to March 28th, 2016.

Promoting the Online Workbook:

Brantford Power promoted the workbook through a number of methods:

- Advertised on the homepage banner of www.BrantfordPower.com
- An extensive print and online advertising and social media campaign
- E-billing email notification messages with a link to the workbook
- On-bill messaging

Below are the results for its Q1 print and online advertising campaign from Brickworks Communications, Inc:

Campaign / Media	Format(s)	Circ	Position	Planned Imps	Actual Imps	Clicks	CTR
001 Q1Campaign							
Print - Brantford							
Brant News	1/2pg, 4C	48,869	pg 21				
Branford Expositor	1/2pg, 4C	13,000	A5 (only ad on the pg 2 spread)				
Brant News	1/4pg, 4C	48,869	pg 4				
Branford Expositor	1/4pg, 4C	13,000	A7				
Digital - Brantford							
www.brantnews.com	Standard Display			20,000	20,469	36	0.18%
www.brantfordexpositor.ca	Standard Display			100,000	100,003	176	0.18%

Overall, the online campaign appeared to drive 212 visits to the website (not the survey itself).

According to Brickworks, the CTR (click-through rates) outperformed the industry average of 0.07% and Metroland average of 0.17%.

In total, the workbook had 674 page visits, 267 partial completes (at least reached the “about” page) and 28 total completes.

While the online campaign appears to have been successful in click-throughs, this did not translate into a large number of completes. Based on INNOVATIVE's previous online workbook consultations, one possible explanation for this may be a lack of financial incentive provided to potential respondents.

Publishing the Workbook Online

INNOVATIVE hosted the workbook at the following URL: *www.BrantfordPowerWorkbook.com*. This website prevented Brantford Power customers from filling out questions more than once and saved progress as they went, allowing them to leave and return to the workbook to finish at a time of their choosing.

The personal information of Brantford Power customers was kept anonymous and confidential on INNOVATIVE's secure business servers. INNOVATIVE does not ever provide links to personal information submitted on Brantford Power's website.

Validating Customer Responses:

Anyone who answered a question in the workbook was tagged with an identification number based on both their postal code and their response as either a Brantford Power residential or business customer. This was then validated against a file provided by Brantford Power of all customer postal codes; those deemed invalid were removed from the final sample. In addition, IP addresses were tracked to ensure respondents were unique and human.

Respondent Profile

Overall, 26 residential and 2 business customers completed the workbook for a total of n=28 completes. Note that open-ended response n-sizes may vary. Due to the small sample size overall, the following analysis will focus on all customers as a whole and will not delve further into demographics (rent vs. own, responsibility for bill, residence type, number in household) and firmographics (work area, monthly spending).

Respondent Feedback

The following sections will examine the feedback from 26 residential and 2 business customers who completed the workbook. (Since only 28 people in total finished, results are reported as n-size only and categories in some questions have been combined as needed.)

Familiarity and Satisfaction

This first section explores respondents' familiarity with the distribution system, perceptions of how the system is explained, and satisfaction and suggested areas of improvement for Brantford Power.

Figure 1: Understanding of Electricity System

Q: Before this consultation, how familiar were you with the various parts of the electricity system, how they work together, and which services Brantford Power is responsible for?

A strong majority of respondents (19/28) self-reported as familiar with Brantford Power's role in the electricity system. Roughly a third (9/28) stated they "heard of some of the terms and organizations, but knew very little" and none of the customers reported they "knew nothing" about Ontario's electricity system.

- Both Business Customers surveyed (2/28 total) felt they were "somewhat familiar" with Brantford Power and its role in the electricity system.

Figure 2: Explanation of Electricity System

Q: Given what you have read so far, how well do you feel Ontario's electricity system has been explained to you?

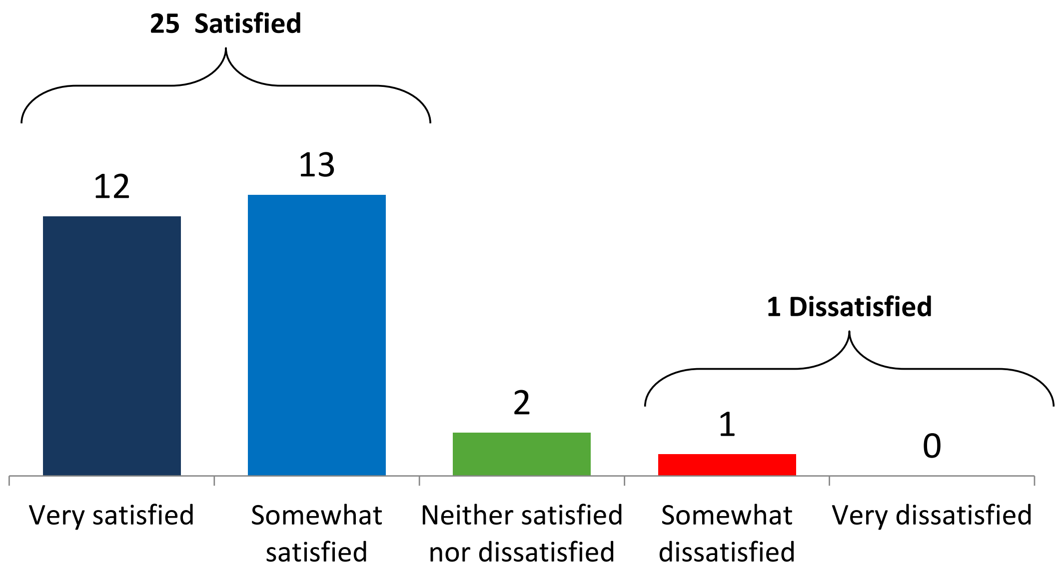
All respondents felt the system had been explained well to them based on what they had read so far with a slight majority (16/28) who thought it had been explained "very well".

- Both Business Customers (2/28 total) thought the workbook explained the system "very well".

Figure 3: Satisfaction with Service, Suggested Improvements

Q: Generally, how satisfied are you with the service you/your business or organization receives from Brantford Power?

Q: Is there anything in particular that Brantford Power can do to improve its service to you/your organization? [OPEN]



Nearly all (25/28) of the customers surveyed felt satisfied with the service they receive from Brantford Power. The remaining three customers were either neutral (2) or somewhat dissatisfied (1).

- Of the two Business Customers surveyed, one felt "very satisfied" with the service while the other had no strong feelings either way.

In the follow-up open-ended question, 12 customers responded with specific feedback, mostly focused on improved communications, reliability and cost reduction:

- *"1. Avoid outages. 2. Lower rates."*
- *"Better, more regular access to outage information through social media"*
- *"Either restore Brantford Power to it's at cost service as a public Utility or reveal how much it contributes annually to the Corporation of the City of Brantford. We are missing full transparency."*
- *"Find ways to reduce the costs as they have been increasing around 30% over the past few years…"*
- *"Include link to provincial smart meter data to see daily usage."*
- *"More information and transparency."*

System Reliability

This next section outlines customer perceptions on outage duration and frequency as well as their preferences regarding reliability versus cost.

Figure 4: Frequency of Outages in Past Year

Q: In 2015, the average Brantford Power customer experienced one power outage. Do you recall how many outages you/your organization experienced in the past year?

A slight majority (15/28) of customers experienced one outage (11) or less (4). A plurality of customers experienced two or more outages (10/28). Three respondents couldn't remember how many outages they received in the past year.

- As for the Business Customers surveyed, one experienced no outages and the other experienced four in the past year.

Figure 5: Frequency of Outages, Acceptability

Q: How many power outages do you feel are reasonable in a year?

Most respondents felt that one (10) or two (8) outages were a reasonable number per year. Less than one-in-five (6/28) felt that three to four outages would be acceptable and two couldn't give a reasonable number. Only two respondents felt that no outages were acceptable.

- Of the two Business Customers who responded, one stated that "no outages were acceptable" while the other thought two was an acceptable number.

Figure 6: Duration of Outages, Acceptability

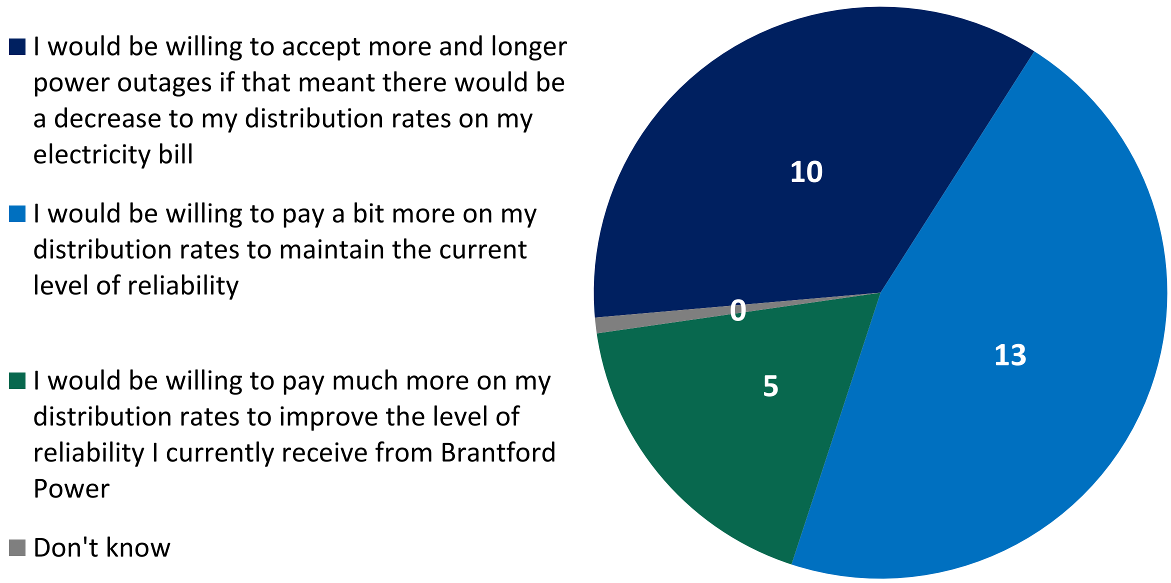
Q: What do you feel is a reasonable duration for a power outage?

A plurality of customers thought that "30 minutes or less" (13/28) would be a reasonable outage duration and more than one-in-four customers (8/28) thought between 30 minutes and an hour would be a reasonable duration for an outage. Only 6 customers felt that outages over an hour long were reasonable.

- Both Business Customers surveyed thought that "15 minutes or less" was a reasonable duration for a power outage.

Figure 7: Reliability vs. Cost

Q: No distribution system can deliver perfectly reliable electricity service. There is a balancing act between reliability and the cost of running the system. Please select what statement comes closest to your point of view.



When asked to choose between three options –accepting longer and more frequent outages to lower distribution rates, paying a bit more to maintain reliability and paying much more to improve reliability- a slight plurality (13/28) of customers would be willing to pay a bit more to improve reliability. More than a third (10/28) of surveyed customers would accept more frequent and severe outages to lower their rates. Only five of the 28 respondents would be willing to pay enough to improve reliability.

- Both Business Customers would be willing to pay more to either maintain (1) or improve (1) reliability.

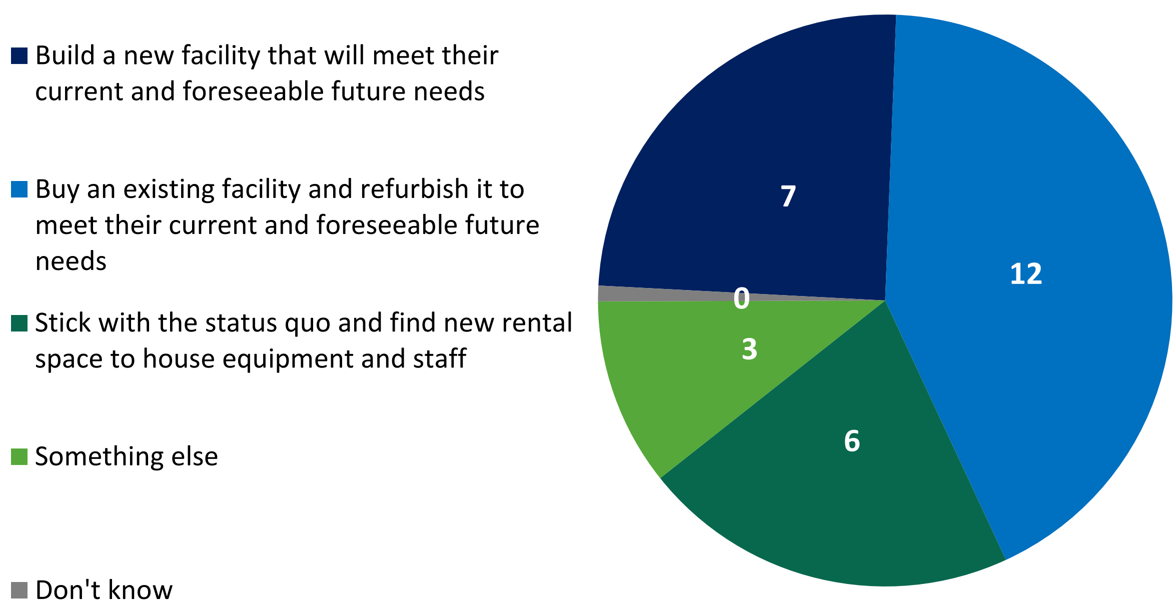
Facility Relocation and Infrastructure Investment

The third section focuses on capital investments and customer preferences on how Brantford Power should meet the challenges of facility relocation and aging infrastructure.

Figure 8: Relocation of Brantford Power Facilities

Q: In terms of Brantford Power's facility relocation, which option do you think your utility should pursue?

Q: (If "Something else") What options do you think Brantford Power should consider in addressing their facility relocation?



Respondents were asked to choose between three specific options on relocating Brantford Power's facility: to build a new one; to buy an existing facility and refurbish it; or to maintain the status quo and find new rental space for equipment and staff. An additional general option ("or something else") was provided as a choice, with the option for respondents to follow-up with their suggestion in an open-ended question.

Between the three options, a plurality (12/28) of respondents would prefer Brantford Power buy an existing facility and refurbish it. About a quarter of respondents feel that Brantford Power should either build a new facility (7) or stick with the status quo (6) and find rental space for its equipment and staff.

Three respondents felt that Brantford Power should consider "something else": one suggested the company consider long-term planning for facilities outside the city core; the second would prefer a lease over office investment; and the final response simply suggested a "merger".

- *"Before building a new consolidated facility, long term planning/decision-making must determine whether the Utility can exist as a stand-alone, or will be swallowed-up in the present climate which would reduce Distributors to 9 province-wide. If a reasonable business plan supports moving forward, build a consolidated stand-alone outside the city core."*
- *"Lease space. Do not invest in office space infrastructure. Also, tender the service aspect to an open bid to ensure we are getting competitive rates by using Brantford Hydro personnel. If not, you should adopt a new business model or outsource those costs to a more competitive third party. Can you share administrative services with other utility providers to reduce costs?"*
- *"Merger."*

Figure 9: Investment in Aging Infrastructure

Q: As a company, Brantford Power needs vehicles and tools to service the power lines and IT systems to manage the system and customer information. Which of the following statements best represents your point of view?

When asked if Brantford Power should make do with its current equipment and IT systems or if it should invest in equipment and tools to manage the system, a strong majority (21) of customers chose the latter option. Just seven respondents felt that Brantford Power should make do with its current assets.

- Both Business Customers felt that Brantford Power should make do with its current equipment and IT systems.

Figure 10: Investment in Buildings, Equipment and IT Systems

Q: With regards to projects focused on replacing aging equipment in poor condition, which of the following statements best represents your point of view?

In a follow-up statement, customers were asked whether Brantford Power should invest "what it takes to replace the system's aging infrastructure", even if means an increase to customers' electricity bills; or if they should lower their investment to "lessen the impact of any bill increase" even if that means more frequent and longer outages.

Half of respondents (14/28) would prefer Brantford Power invest in its aging infrastructure, despite bill increases while 11 out of 28 respondents think Brantford Power should reduce their investment to lessen the economic impact. Three respondents had no strong opinions either way.

- Of the two Business Customers surveyed, one felt that Brantford Power should lessen investment while the other was unsure of which option to choose.

Cost Drivers and Cost Savings

This next section examines customer understanding of the cost drivers facing their local distribution system and Brantford Power's perceived success in managing these drivers.

Figure 11: Understanding and Management of Cost Drivers

Q: How well do you feel you understand the cost drivers that Brantford Power is responding to?

Q: How would you rate the job Brantford Power is doing to manage these cost drivers?

All respondents self-report that they understand the cost drivers facing Brantford Power (7: "very well"; 21 "somewhat well").

A strong majority (22/28) of respondents think Brantford Power is doing a good job to manage these cost drivers. Just 4 in 28 think Brantford Power is doing a poor job and two respondents don't know enough to say.

- Both Business Customers feel they understand the cost drivers "very well" and are divided on whether or not Brantford Power is doing a "good" (1) or "poor" (1) job of handling them.

Figure 12: Reasonableness of Expenses

Q: Do any of Brantford Power's forecasted expenses or expenditures appear unreasonable to you? If so which areas appear unreasonable and why?

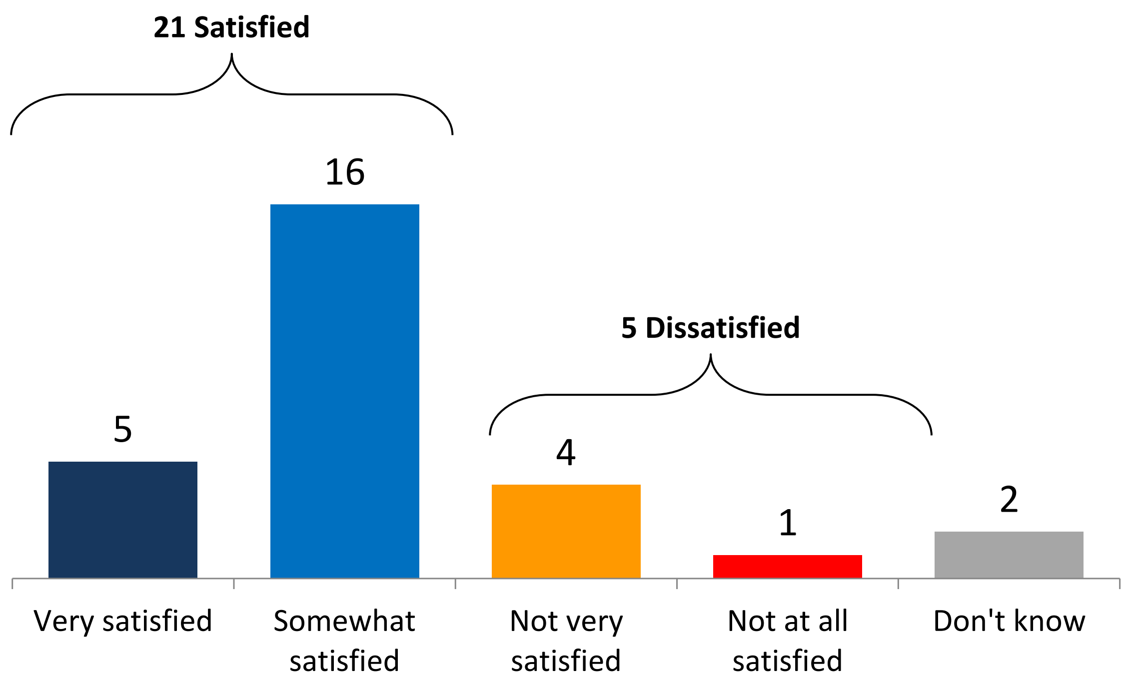
Only three respondents felt Brantford Power's expenditures appear unreasonable (and explained themselves.) Two of the three responses focused on staffing levels and related costs while the remaining comment called on Brantford Power to open its procurement competitively to worldwide providers:

- *"Anything that requires spending more money on staff and related costs should not be considered…"*
- *"How do you establish the forecasted capital expenditures? You need to source your capital from worldwide providers, not just local. You need to open your procurement to ensure the most competitive offers for all major expenditures."*
- *"Revisit staffing levels. Why are six on a job that two people could be doing?"*

Figure 13: Satisfaction with Brantford Power's Cost Savings

Q: How satisfied are you with the efforts Brantford Power has made to find efficiencies and cost savings in the distribution system?

Q: Is there anything else you think Brantford Power should be doing to find efficiencies and cost savings in the distribution system? [OPEN]



Three-in-four (21/28) respondents felt satisfied with Brantford Power's efforts to find cost savings. Only five respondents felt unsatisfied with Brantford Power's cost saving efforts and two did not know enough to say.

- Both Business Customers felt unsatisfied with Brantford Power's cost savings in the distribution system.

In a follow-up open-ended question, seven customers responded with specific ways Brantford Power could find additional efficiencies and cost savings. Some suggested alternative energy conversion while others felt Brantford Power could improve efficiencies through staffing, providing additional billing information to customers, research on infrastructure or setting up an outside audit:

- *"Complete review of staff and job-specific duties…"*
- *"Give customers daily Smart Meter data to see usage and costs. Monthly billing online is a start…"*

- *"Another way to distribute from the power generators would ultimately be beneficial. The idea of using these high-powered cables is getting too old. There has to be a better way, and I am wondering what research is going on at this time."*
- *"Invest in solar energy."*
- *"Move more to assisting customers in converting to hybrid systems such as wind/hydro, solar/hydro. Work with government-owned locations such as municipalities, school boards to add solar collectors to the buildings. Work with large businesses to do the same."*
- *"Periodically, hire an outside audit firm to evaluate current employee practices with recommendations for cost efficiencies."*
- *"…You need to look at different business models, more competition, more options to buy your power, not just Ontario Hydro. Have you looked at your own power generation, say a Co-Gen at the landfill or other options?"*

Plan for the Future and Social Permission

In the last section, customers provided feedback on Brantford Power's plan for the future and the proposed rate increase.

Figure 14: Direction of Investment Plan

Q: From what you have read here and what you may have heard elsewhere, does Brantford Power's investment plan seem like it is going in the right direction or the wrong direction?

Q: Why do you feel this way? [OPEN-ENDED]

A strong majority (18/28) of respondents feel that Brantford Power's investment plan is going in the "right direction" with only two respondents who feel it is headed in the "wrong direction". The remaining eight customers don't know enough to say.

In the follow-up open-ended, positive responses speak to "common sense", "prudent" and "proactive approach" of Brantford Power and an understanding that "higher costs are an understandable consequence of this improvement":

- *"I think this approach is needed. But we also need a much better and totally different transmission system."*
- *"It appears that good business planning and common sense are being used."*
- *"It is important that Brantford Power make use of new technology in order to improve reliability of service and overall customer experience. Higher costs are an understandable consequence of these improvements."*
- *"Looks like a pro-active approach from what I understand."*
- *"Prudent planning and realistic expectations of needed maintenance and upgrades."*
- *"They have done their homework on other pros and cons."*

- *"We need to have safe and reliable equipment for employees. A central building makes sense to me."*
- *"Well-laid out plan."*

Figure 15: Planning for Future

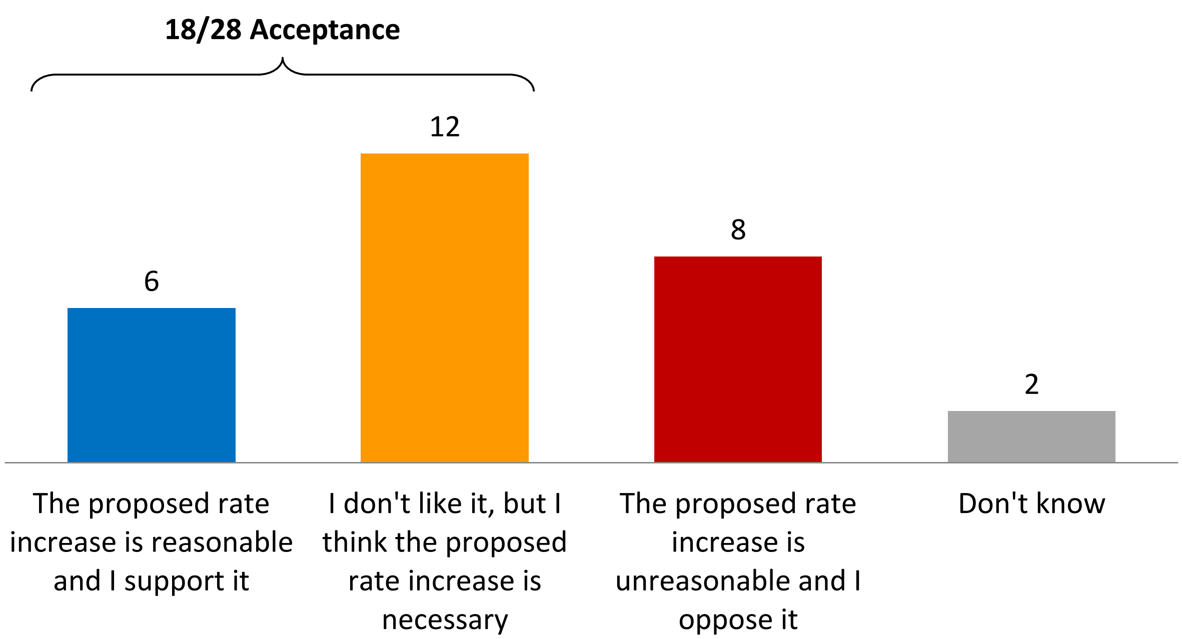
Q: How would you rate the job Brantford Power is doing when it comes to planning for the future?

A strong majority (19/28) of customers think Brantford Power is doing a good job planning for the future. Just two respondents felt Brantford Power is doing a poor job of planning and seven respondents didn't know enough to say.

Figure 16: Social Acceptance for Rate Increase

Q: Considering what you know about the local distribution system, which of the following best represents your point of view?

Q: Thinking about your answer to the previous question, why do you either support the proposed rate increase, think the proposed rate increase is necessary, oppose the proposed rate increase, or don't know?



On the permission question, most respondents (18/28) support the proposed rate increase:

- Six customers support the rate increase unconditionally;
- 12 customers don't like the rate increase, but agree it's necessary;
- Eight customers think the rate increase is unreasonable and oppose it;
- And two customers are still on the fence as to whether to support or oppose the increase.

Both Business Customers surveyed oppose (2) the rate increase.

When asked to explain their reasoning, those who support the rate increase mostly cited the need to maintain reliability for essential services. That being said, there were clear concerns about the rising cost of living and the difficulty among seniors to keep pace with rising electricity rates:

- *"Although electricity is considered an essential service, people lose the understanding that there are ongoing costs to maintain the service and improve the service as need demands."*

- *"Even though I may understand all the reasons for increases, hydro is only a portion of my household expenditures; and all increase every month, every year. As a senior, my income does not match these increases."*
- *"Full support from here, it is just the right thing to do. How would you expect your car to run, if you didn't pay attention to it?"*
- *"I am retired so I don't like more expense but as I said safety is important and one building is the way to go."*
- *"It's inevitable nothing stays the same and unfortunately I expect everything to rise as does the cost of living and hopefully paycheques and inflationary rates with pensions."*
- *"No one likes rate increases. My pension is NOT increasing in line with ANY increases by utilities, governments, groceries, etc."*
- *"It avoids a monopoly distribution in this province."*
- *"I think the proposed rate increase is necessary."*

Among those that oppose the rate increase, the main reason mentioned is cost, particularly in relation to other provinces:

- *"Costs vs. other provinces…"*
- *"I think you should have shown the rate increase over the past 5 years and not start at 2016. I don't have any faith in your ability to manage costs effectively based on past history."*
- *"Many other cost savings could be achieved such as cost of staff and benefits. Better management of resources."*
- *"Ontario has the highest hydro rates in the country. As a senior living on a fixed income I dread the arrival of the hydro bill in my mailbox. Every month the bill increases even though we try to use our appliances according to the low peak rate times, it doesn't seem to matter…"*
- *"Use the debt retirement charge to lower everyone's bills and we would be a little happier…"*

Feedback on the Workbook Design

After completing the workbook, respondents were asked five questions about the survey itself:

- *Overall Impression: What did you think about the workbook?*
- *Volume of Information: Did Brantford Power provide too much information, not enough, or just the right amount?*
- *Content Covered: Was there any content missing that you would have liked to have seen included?*
- *Outstanding Questions: Is there anything you would still like answered?*
- *Suggestions for Future Consultations: How would you prefer to participate in these consultations?*

14 of the 28 respondents completed all the feedback questions.

Overall impression from the open-ended responses was quite positive: it was "interesting", "well-designed", "very thorough", and "well-presented". Only a few respondents provided negative feedback, one stating it was "too much like a sales pitch".

- *"Interesting, well-thought out, informative."*
- *"Asked a lot of questions, but could have gone deeper."*

- *“Excellent survey- well-designed.”*
- *“Glad we were offered the opportunity.”*
- *“Good, informative, but too long.”*
- *“Very informative.”*
- *“This sounded too much like a sales pitch to justify what you want to do.”*
- *“Very thorough, clear and well-presented.”*

As for the volume of information in the workbook, opinion was mixed. Some thought it was a bit “too much”, others thought it was just enough to inform them.

- *“A bit much but not overdone - very close to right - for me!”*
- *“A little too much.”*
- *“Amount is necessary to inform consumers.”*
- *“Enough and right amount.”*
- *“Enough for the average user.*
- *“Lots of technical info but I did understand some or most of it.”*
- *“Maybe a little too much.”*
- *“Possibly too much information for the average customer.”*

Most of the 14 respondents did not think anything was missing from the workbook. Those that did cited “smart meter discussion”, “cost management and containment” and “annual profits to the city.”

- *“A discussion about smart meters and the time of day rates.”*
- *“Cost management and containment. What are you doing differently to improve your cost control and reduce burden on your customers…”*
- *“Don't think so.”*
- *“No.”*
- *“No, not really.”*
- *“Why smart meter data is not provided currently.”*
- *“Yes -annual profits to the city.”*

Some outstanding questions listed by respondents include “renewable energy strategy as it relates to local future supply”, “smart meter data” and research to plan beyond 2021.

Finally, on “Suggestions for Future Consultations”, respondents thought it could be done by “email”, “focus group” or were satisfied by this method.

- *“Email”*
- *“Include a focus group of informed citizens to review survey results.”*
- *“Same way.”*
- *“This is best for me but not all people. Paper addressed in the mail I understand is way too expensive but perhaps a modified version in a paper bill could be included or requested for by a resident.”*
- *“This method seems to be satisfactory.”*

Customer Telephone Surveys

Telephone Surveys
among Residential and GS Customers

PURPOSE: To obtain statistically significant quantitative feedback on the proposed system plan spending and assess reaction to customer opinions obtained from the previous research phases

Summary

This section summarizes the telephone survey results of 502 residential (RS) and 100 General Service (GS) customers.

Familiarity and Satisfaction

- Almost seven-in-ten residential (68%) and General Service customers are familiar with Brantford Power.
- The large majority of both residential (86%) and General Service (85%) are satisfied with the service they receive from Brantford Power.
- Lowering rates was the most commonly suggested improvement for both residential (35%) and General Service (37%) customers.

Electricity Bill Knowledge

- Around one-in-three (32% residential; 27% General Service) were familiar with the percentage of their electricity bill that is remitted to Brantford Power before taking part in this survey.
- Half (48%) of residential and the majority (57%) of General Service customers say that the proportion of their bill allocated to Brantford Power is reasonable.

System Reliability

- Residential customers most commonly experienced one outage in the year prior (22%). Of those who did experience an outage, half (50%) report that the most recent outage lasted less than 15 minutes.
    - The plurality (29%) of General Service customers report having no outages in the year prior. Of those who did experience an outage, three-in-ten say that it lasted *less than 15 minutes* (30%) or *15 minutes to less than 30 minutes* (29%).
- In terms of impact, the plurality (64%) found the last outage that they had experience to be a minor convenience, while 27% found it to be no inconvenience at all.
    - The plurality (46%) of General Service customers say that the most recent outage *barely any cost to their business, just a bit of inconvenience*; one-third say it *had a minor cost to their business*.
- Satisfaction with system reliability, determined by the different measures, is quite high.

    - *The reliability of your electricity service as judged by the number of power outages you experience*: 90% residential; 92% General Service.
    - *The amount of time it takes to restore power when power outages occur*: 87% residential; 80% General Service.
    - *The quality of power delivered to you as judged by the absence of voltage fluctuations that can result in the flickering or dimming of lights*: 87% residential; 80% General Service.
- Half (50%) of residential and 53% of General Service customers feel that Brantford Power should *spend what is needed to maintain the current level of outages.*
- 52% of residential and 57% of General Service customers feel that Brantford Power should *spend what is needed to maintain the current length of unexpected outages*.

System Challenges & Priorities

- Half (50%) of residential customers and general Service Customers (51%) feel that Brantford Power should invest what it takes to replace the system's aging infrastructure to maintain system reliability.
- 79% of residential and 76% of General Service customers feel that it is important for Brantford Power to invest now in modernizing the grid.
- Two-in-five (41%) residential and 36% of General Service customers currently participate in a Brantford Power conservation program. Higher consumption customers are more likely to currently participate in a program.
- 74% of residential and 73% of General Service customers say they are likely to participate in a Brantford Power conservation program in the future.
- Four-in-five (81%) residential and 64% of General Service customers think that Brantford Power does a good job at providing them with information on available tools and programs that can help them manage their electricity consumption.
- Buying a new facility that will meet current and foreseeable future needs (43% residential; 39% General Service) is the most commonly suggested solution for facility relocation. This is followed by building a new facility (17%) for residential customers, and finding a new rental space to house equipment and staff (22%) for General Service customers.

Overall Assessment of Plan

Residential Acceptance: 65%

Top 3 Reasons for Willing Acceptance	
Q: And why do you say that? [Asked of residential respondents who had an opinion on Brantford Power's proposed rate increase]	
Must invest now or risk paying more later	39%
It is reasonable / $5 is fine	37%
Everything is going up / inflation	9%

General Service Acceptance: *68%*

Top 3 Reasons for Willing Acceptance	
Q: And why do you say that? [Asked of residential respondents who had an opinion on Brantford Power's proposed rate increase]	
It is necessary/system needs upgrading/need power	51%
It is not a significant increase	25%
Everything is going up	4%

Methodology

INNOVATIVE conducted two customer surveys by telephone for Brantford Power:

1. A residential customer survey conducted among **502 respondents** between March 29 and April 2, 2016.
2. A General Service customer survey conducted among **100 respondents** between March 29 and April 8, 2016.

Participants were randomly selected from customer lists provided by Brantford Power (30,629 residential records; 1736 General Service records).

- A sample of 502 residential customers is considered accurate to within ±4.3 percentage points, 19 times out of 20.
- A sample of 100 General Service customers is considered accurate to within ± 9.4 percentage points, 19 times out of 20.

The margin of error in both surveys will be larger within each sub-grouping of the samples.

Questionnaire Design

The questionnaires were designed to simulate the journey that respondents in the Workbook-led Consultation Sessions experienced. This included a combination of educating the customer, having customers reflect on their personal experience with their distribution system, and having them make value judgments on trade-offs between system reliability and bill impact.

As part of simulating the "*workbook journey*", the questionnaires were informed by and incorporated feedback from the previous phases of Brantford Power's customer engagement. This included sharing both supportive and non-supportive feedback in the survey from previous phases of Brantford Power's customer consultation as it related to Brantford Power's proposed capital investment and the associated rate increase. Wording of questions differed slightly between the Residential and General Service survey – for example, in the preambles the size of monthly bills differed between residential and General Service customers – but otherwise remained consistent.

The average survey ran at approximately 10 minutes. Both survey instruments can be found at the end of this section of the report.

Fielding the Survey

Residential (RS) Customer Survey:

For the purposes of executing the residential survey, Brantford Power provided INNOVATIVE with a confidential list containing **30,629** of their residential customers' contact information.

The contact list included only residential customers with residential telephone contact information on file and who had been a customer of Brantford Power since at least January 1, 2014. The information contained in the contact list included customer name, telephone number, FSA and total annual usage between January 1 and December 31, 2015.

Only one customer per household was eligible to complete the residential survey. Survey respondents were screened to certify that only the resident primarily responsible for paying their Brantford Power electricity bill was interviewed. This step was taken to ensure that survey respondents represented the most qualified person within a household to answer questions about their electricity bill and whether Brantford Power's proposed rate increase would have a relative impact on their bill.

Before retiring any randomly selected telephone number from the contact list, 8 attempts were made to reach a potential respondent for each unique telephone number, or until an interviewer received a hard refusal. Each night a new sample was released from the contact list to replace completed or retired numbers.

Brantford Power's residential customers were contacted by telephone between 4pm and 9pm on weekdays; between 10am and 9pm on Saturdays; and between 11am and 9pm on Sundays.

General Service Customer Survey:

The sample for the General Service survey consisted of 100 customers drawn from a confidential list provided to INNOVATIVE by Brantford Power. General Service respondents were screened to ensure they were in charge of managing the electricity bill at their organization.

General Service customers were contacted on weekdays between 9am to 4pm.

All fieldwork was conducted using INNOVATIVE's computer-assisted telephone interviewing (CATI) system.

Sample Design

The two surveys followed a stratified random sampling methodology. This is a method of sampling that involves the division of a population into smaller groups known as strata. In stratified random sampling, the strata are formed based on members' shared attributes or characteristics (in this case, customer service area or electricity usage). A random sample from each stratum is taken in a number proportional to the stratum's size when compared to the customer population. These subsets of the strata are then pooled to form a random sample.

In both surveys, residential and General Service customers were divided into quartiles based on annual electricity usage to ensure the sample had a proportionate mix of customers from low, medium-low, medium-high, and high electricity usage households.

Residential and General Service Sample Design:

Brantford Power customers were divided into quartiles based on annual electricity usage. The following table illustrates the segmentation of the residential and General Service customer survey samples by usage quartile.

Customer Type		Total Sample	Low	Medium-Low	Medium-High	High
Residential	Target	500	125	125	125	125
	Actual	502	125	126	125	126
	Difference	+2	0	+1	0	+1
General Service	Target	100	25	25	25	25
	Actual	100	20	29	32	19
	Difference	0	-5	+4	+7	-6

Sample Weights

Weights have <u>not</u> been applied to the residential sample as the stratified random samples are accurate representations of Brantford Power's actual residential customer distribution. Weights have been applied to the General Service sample based on quartiles to accurately reflect customer distribution.

Financial Flexibility

One measure noted throughout this report is "financial flexibility", also referred to as "financial strain". Financial strain was determined by agreement with a customer input statement which indicated that the cost of their electricity bill has a major impact and requires customers to do without – or put off – other investments or spending priorities. Customers who agreed with this statement (responded *strongly agree* or *somewhat agree*) were classified as financially strained. This measure was included in a cross-tabulation of the survey results. They were also asked if they feel customers are well serviced by the electricity system in Ontario.

Demographic Profile

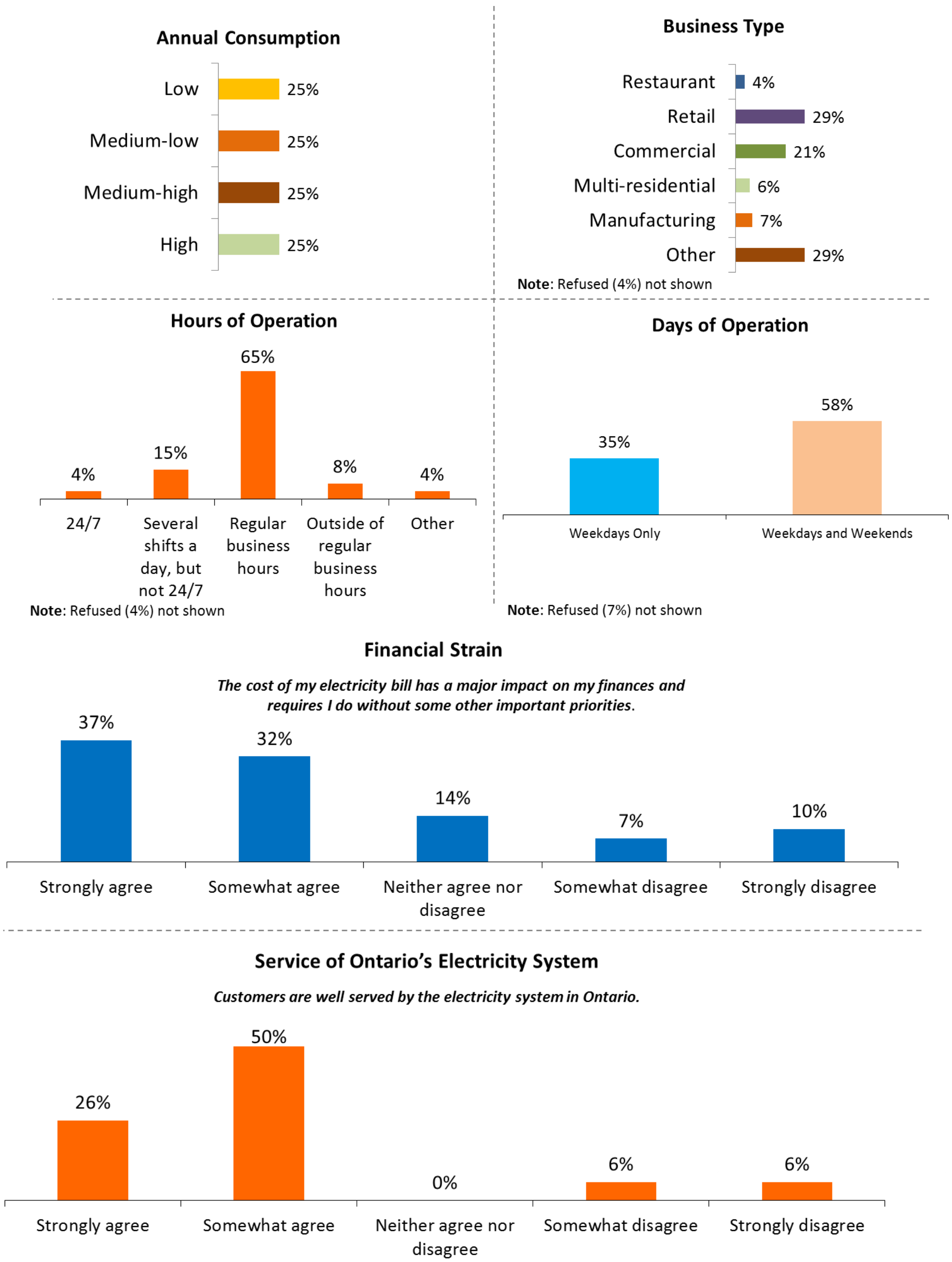
The following details the demographic characteristics of customers who completed the Residential Ratepayer Survey [n=502].

Figure A: Residential Customer Profile

Firmographic Profile

The following details the firmographic characteristics of customers who completed the General Service Ratepayer Survey [n=100].

Figure B: General Service Customer Profile



Respondent Feedback

Familiarity and Satisfaction

The first section of the survey determined customers' familiarity with Brantford Power and gauged their level of satisfaction with the service that they receive. They were also asked if anything could be done to improve service to them.

Familiarity and Satisfaction Summary

- Around seven-in-ten residential (68%) and General Service (72%) customers are familiar with Brantford Power.
- Satisfaction with the services provided by Brantford Power is high among both residential (86%) and General Service customers (85%).
- One-in-three (35%) residential customers feel that Brantford Power could improve service by reducing rates, almost the same proportion (34%) have no suggestions to offer.
- 37% of General Service customers say that Brantford Power could improve service by lowering rates, while three-in-ten (32%) have no suggestions to offer.

Preamble for Familiarity and Satisfaction Section

Prior to answering the questions in the General Satisfaction Section, customers were presented with the following preamble introducing the survey:

Below is the preamble for **residential customers**:

"To begin, I'd like to ask you some questions about your electricity service.

*Today we want to talk about **Brantford Power** and the local electricity system in your community. This is the system that takes the electricity from provincial transmission towers and brings it to your home through a network of wires, poles and other equipment that is owned and operated by **Brantford Power.**"*

General service customers were given additional introduction to ensure that their responses pertained to their experience at their organization:

*"While you may be a **Brantford Power** residential customer, for the following questions I'd like you to answer from the perspective of the **business or organization** that you represent. While we are currently surveying residential customers, you have been randomly selected from a limited sample of small business and non-residential customers and it's important we understand the unique needs and preferences of this group of customers.*

So again, please answer the following questions from the perspective of your business or organization's needs and preferences.

To begin, I'd like to ask you some questions about your electricity service.

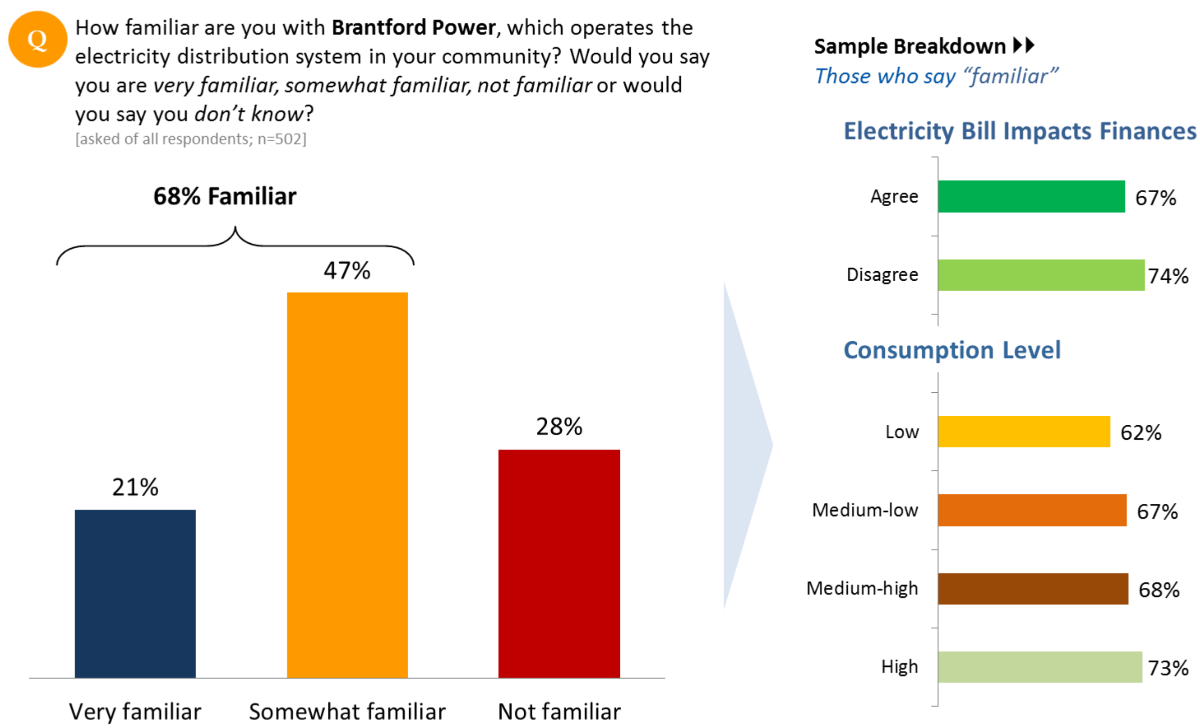
*Today we want to talk about **Brantford Power** and the local electricity system in your community. This is the system that takes the electricity from provincial transmission towers and brings it to your home through a network of wires, poles and other equipment that is owned and operated by **Brantford Power.**"*

Familiarity with Local Electricity Distribution System

The majority (68%) of residential customers are familiar with Brantford Power. Two-in-ten (21%) are *very familiar*, 47% are *somewhat familiar*, and 28% are *not familiar.*

- Those who disagree that their electricity bill impacts their finances are more familiar (74%) with the company that operates the electricity distribution system, than those who agree (67%)
- Familiarity with Brantford Power increases with electricity consumption.

Figure RS.1: Familiarity with the Local Distribution System

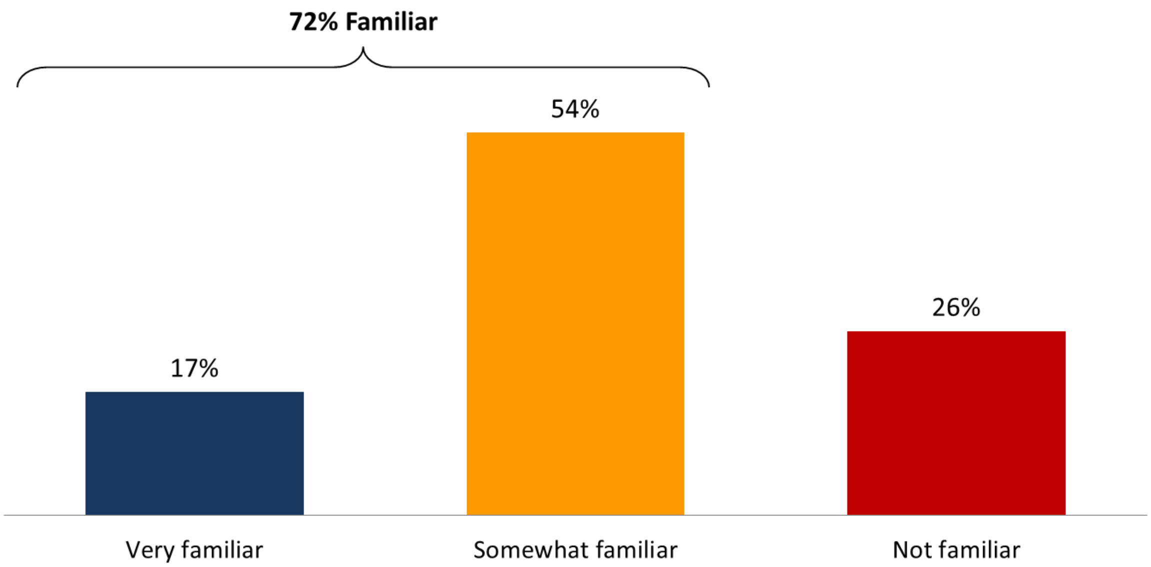


Note: 'Don't know/Refused' (5%) not shown.

Seven-in-ten (72%) General Service customers are familiar with Brantford Power. The majority (54%) are *somewhat familiar,* while 17% are *very familiar,* and 26% are *not familiar*.

Figure GS.1: Familiarity with the Local Distribution System

Q How familiar are you with **Brantford Power**, which operates the electricity distribution system in your community? Would you say you are *very familiar, somewhat familiar, not familiar* or would you say you *don't know*?
[asked of all respondents; n=100]



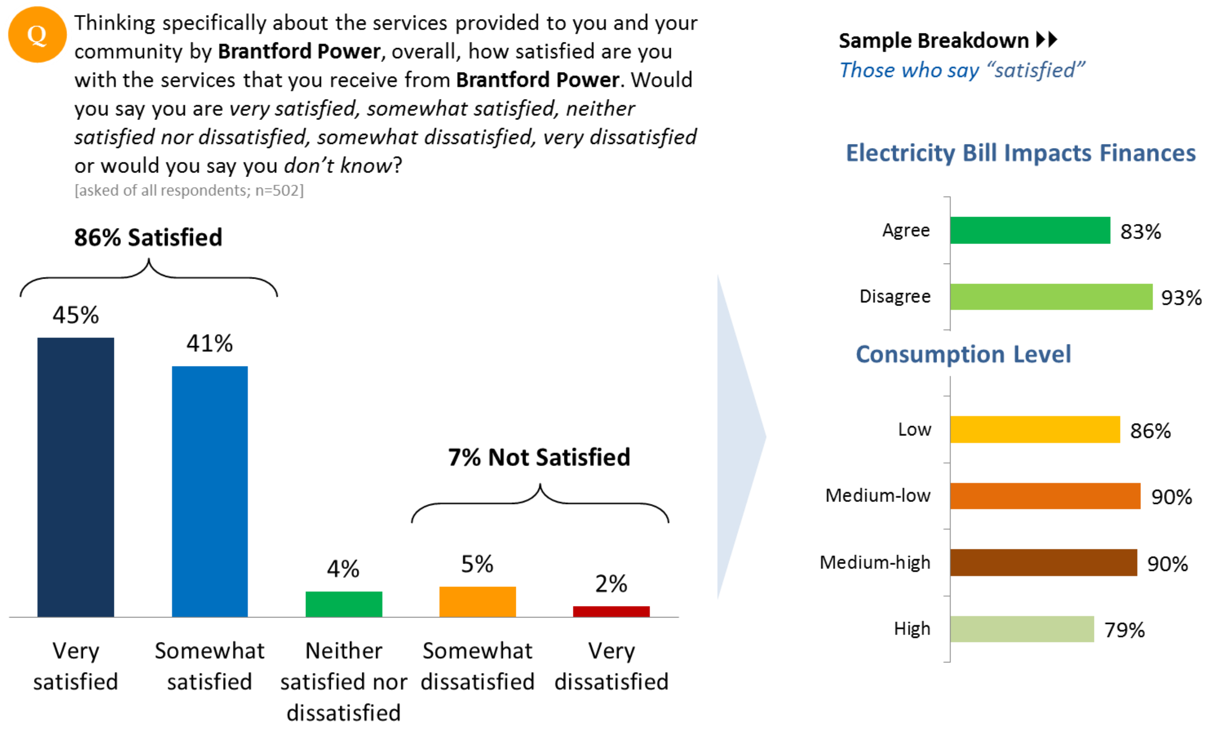
Note: 'Don't know' (2%) not shown.

Satisfaction with Services Received from Brantford Power

The majority of residential customers (86%) are satisfied with the services provided by Brantford Power. Only 7% are dissatisfied, while 4% are *neither satisfied nor dissatisfied*.

- 10% fewer customers who are impacted by their bill than those who are not are satisfied (83% agree vs. 93% disagree).
- Medium-range consumption customers are the most satisfied (90%), while high consumption customers are the least (79%).

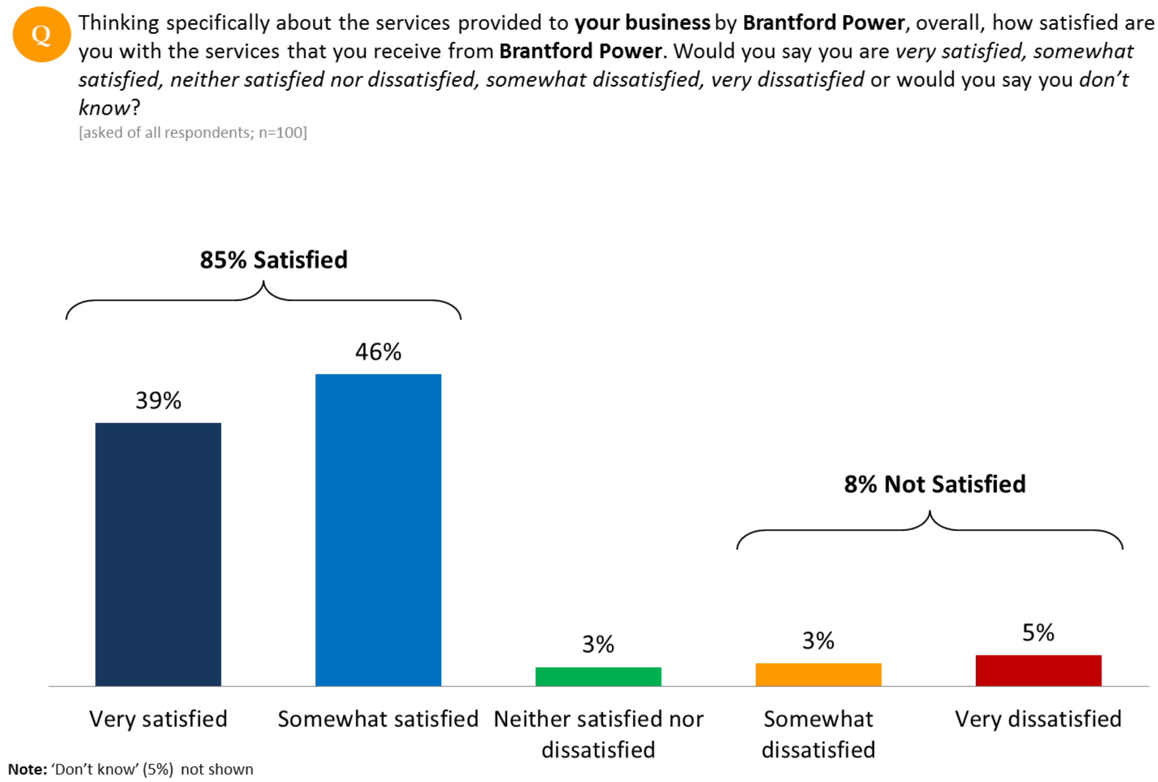
Figure RS.2: Satisfaction with Brantford Power



Note: 'Don't know/'Refused' (3%) not shown

Thinking specifically about services provided to their businesses, 85% of General Service customers are satisfied. 39% are *very satisfied* and 46% are *somewhat satisfied*. Almost one-in-ten (8%) are not satisfied.

Figure GS.2: Satisfaction with Brantford Power

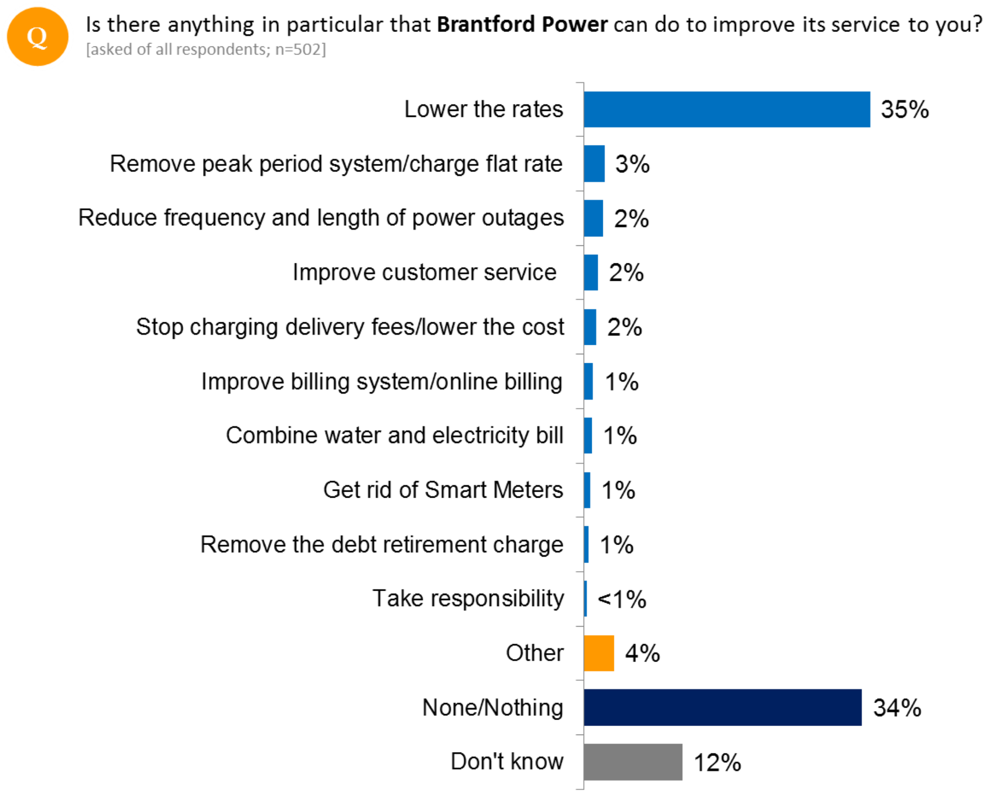


Improving Service

Customers were asked if there is anything in particular that Brantford Power could do to improve service to them. Responses to this open-ended question were coded and ranked accordingly.

The most common improvement suggested by residential customers is to lower rates (35%), however an almost identical proportion (34%) say that there is nothing that Brantford power could do.

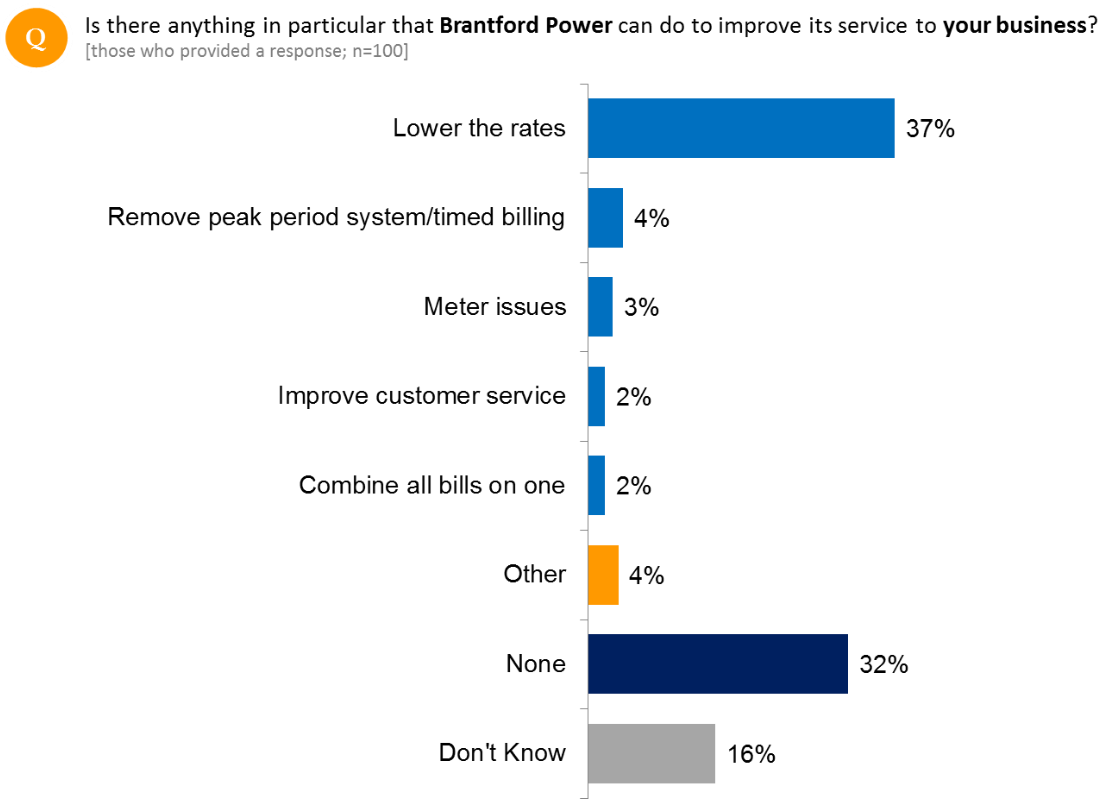
Figure RS.3: Improving Service



Note: 'Refused' (2%) not shown

The only suggestion proposed by more than 5% of General Service customers is to *lower the rates* (37%). One-in-three (32%) have no suggested improvements to offer, while 16% *don't know*.

Figure GS.3: Improving Service



Bill Knowledge and Impact

Customers were read a preamble explaining that while Brantford Power is responsible for collecting payment, 17% (residential) or 13% (General Service) of the bill is allocated to Brantford Power. They were then asked how familiar they were with how their bill is broken down, and how reasonable they felt this to be.

Electricity Bill Knowledge Summary

- One-in-three (32%) were familiar with the percentage of their electricity bill that is remitted to Brantford Power before taking part in this survey. Familiarity increase slightly with consumption.
- One-quarter (27%) of General Service customers were familiar; the majority (57%) were not.
- Half (48%) of residential and the majority (57%) of General Service customers say that the proportion of their bill allocated to Brantford Power is reasonable.

Preamble for Bill Knowledge & Impact Section

Below is the preamble for **residential customers**:

"I'd now like to talk with you about your electricity bill …

*While **Brantford Power** is responsible for collecting payment for the entire electricity bill, they retain only about **17%** of the average residential customer's bill. The rest of the bill goes to power generation companies, transmission companies, the provincial government and regulatory agencies."*

General service customers were read the following preamble:

*"I'd now like to talk with you about **your business**' electricity bill …*

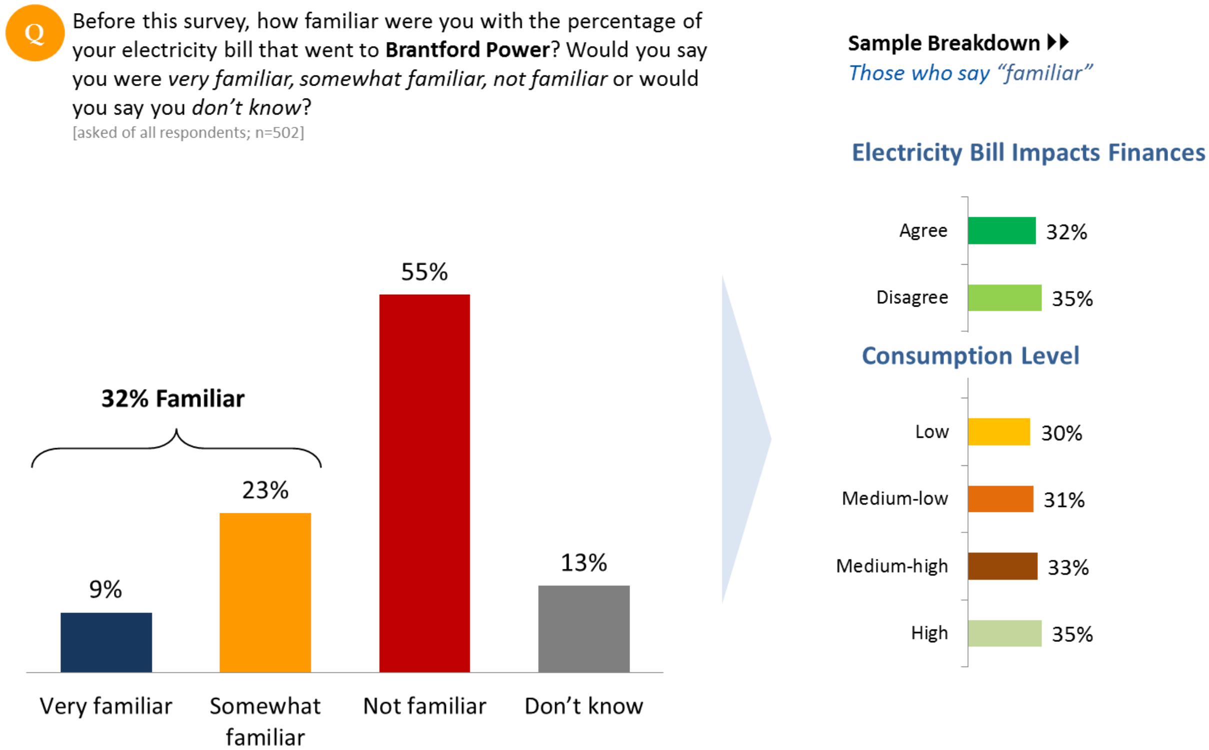
*While **Brantford Power** is responsible for collecting payment for the entire electricity bill, they retain only about **13%** of the average **General Service or small business** customer's bill. The rest of the bill goes to power generation companies, transmission companies, the provincial government and regulatory agencies."*

Familiarity with Percentage of Bill Allocated to Brantford Power

More than half (55%) of residential customers were not familiar with how much of their electricity bill went to Brantford Power prior to this survey. 23% were *somewhat familiar*, and 9% were *very familiar*.

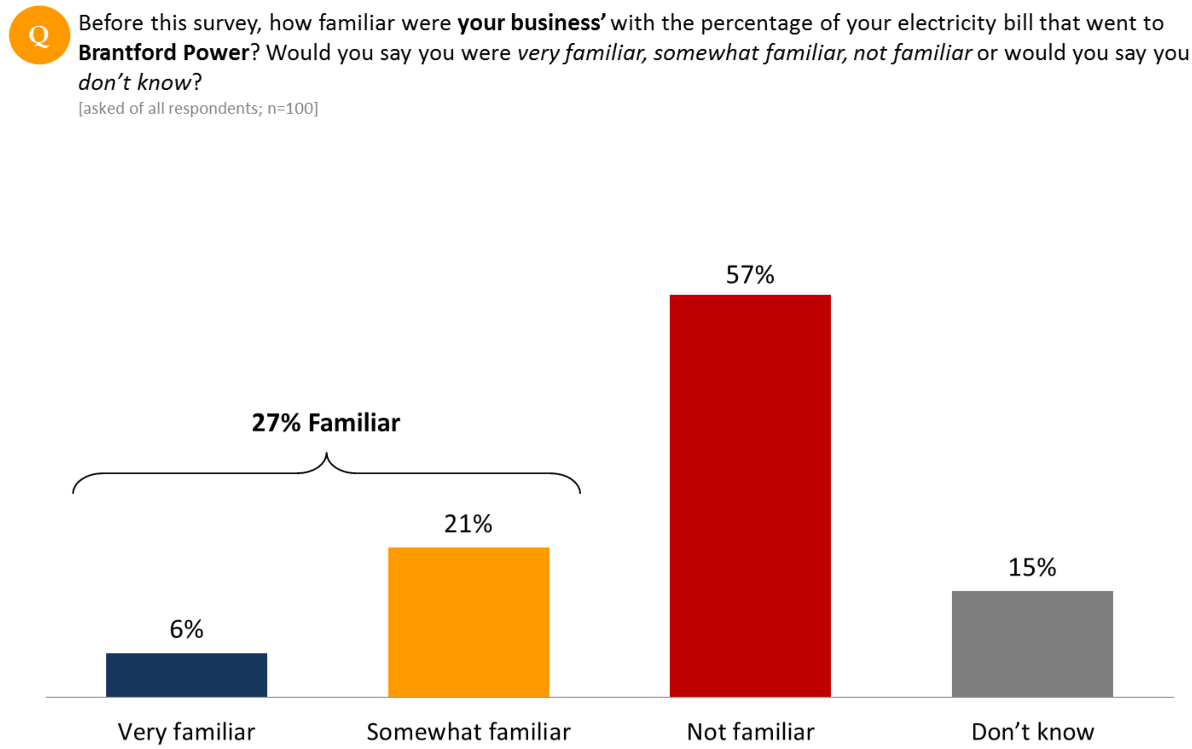
- Prior knowledge of bill allocation increases slightly with consumption from 30% (low) to 35% (high).

Figure RS.4: Familiarity with Percentage of Bill Allocated to Brantford Power



Before this survey 27% of General Service customers were familiar with the percentage of their bill that is allocated to Brantford Power. The majority (57%) were not familiar.

Figure GS.4: Familiarity with Percentage of Bill Allocated to Brantford Power



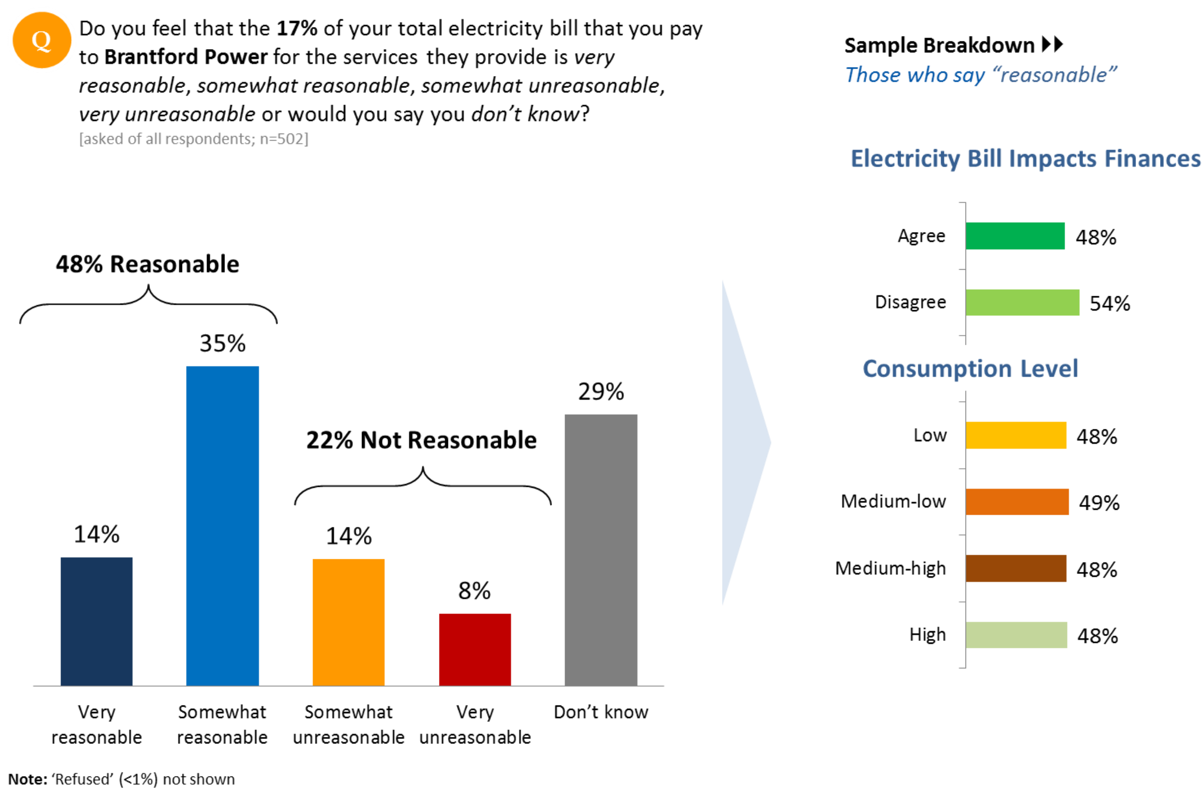
Note: 'Refused' (1%) not shown

Bill Allocation is Reasonable

Almost half (48%) of residential customers feel that it is reasonable that the 17% of their total electricity bill payed to Brantford Power is reasonable. The plurality (35%) feel that this is *somewhat reasonable,* while 14% feel that this is *very reasonable.* However, three-in-ten (29%) *don't know*, that is, they are unable to say one way or the other.

- Customers who are not financially strained (54%) are more likely to say reasonable than those who are financially strained (48%).
- There are no meaningful differences in terms of consumption.

Figure RS.4: Bill Allocation is Reasonable

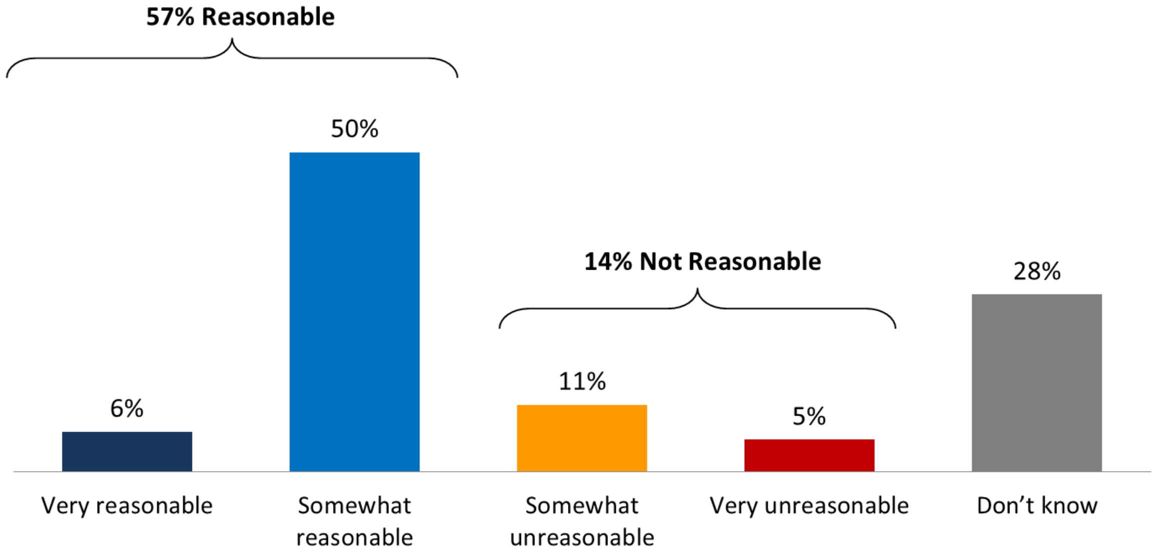


Bill Allocation is Reasonable

The majority (57%) of General Service customers feel that the 13% of their total bill they pay to Brantford Power is reasonable, 14% feel that it is not reasonable, and similar to residential customers three-in-ten (28%) *don't know.*

Figure GS.5: Bill Allocation is Reasonable

Q Do you feel that the **13%** of your total electricity bill that you pay to **Brantford Power** for the services they provide is *very reasonable*, *somewhat reasonable*, *somewhat unreasonable*, *very unreasonable* or would you say you *don't know*?
[asked of all respondents; n=100]



System Reliability

This section covers the feedback provided by customers on power service interruptions occurring over the past year. They were asked to describe the frequency and duration of outages, in addition to the impact that they have on their household or organization. This series of questions also investigates perceptions around spending, and reducing the number and length of power service interruptions.

System Reliability Summary

- Residential customers most commonly experienced one outage in the year prior (22%). Of those who did experience an outage, half (50%) report that the most recent outage lasted less than 15 minutes.
    - The plurality (29%) of General Service customers report having no outages in the year prior. Of those who did experience an outage, three-in-ten say that it lasted *less than 15 minutes* (30%) or *15 minutes to less than 30 minutes* (29%).
- In terms of impact, the plurality (64%) found the last outage that they had experienced to be a minor convenience, while 27% found it to be no inconvenience at all.
    - The plurality (46%) of General Service customers say that the most recent outage *barely any cost to their business, just a bit of inconvenience*; one-third say it *had a minor cost to their business*.
- Satisfaction with system reliability, determined by the different measures, is quite high.
    - *The reliability of your electricity service as judged by the number of power outages you experience*: 90% residential; 92% General Service.
    - *The amount of time it takes to restore power when power outages occur*: 87% residential; 80% General Service.
    - *The quality of power delivered to you as judged by the absence of voltage fluctuations that can result in the flickering or dimming of lights*: 87% residential; 80% General Service.
- Half (50%) of residential and 53% of General Service customers feel that Brantford Power should *spend what is needed to maintain the current level of outages.*
- 52% of residential and 57% of General Service customers feel that Brantford Power should *spend what is needed to maintain the current length of unexpected outages*.

Preamble for Power Service Interruptions

The following questions focused customers' experience with unexpected power outages and how they feel Brantford Power should manage such outages.

This preamble introduced the section and provided customers with the average number of outages a year. It was read to both **residential** and **General Service** customers:

"Despite best efforts, no electrical distribution system can deliver perfectly reliable electricity. As a general rule, the more reliable the system, the more expensive the system is to build and maintain.

*With that said, the average **Brantford Power** customer experiences **<u>one</u>** unexpected power outage per year."*

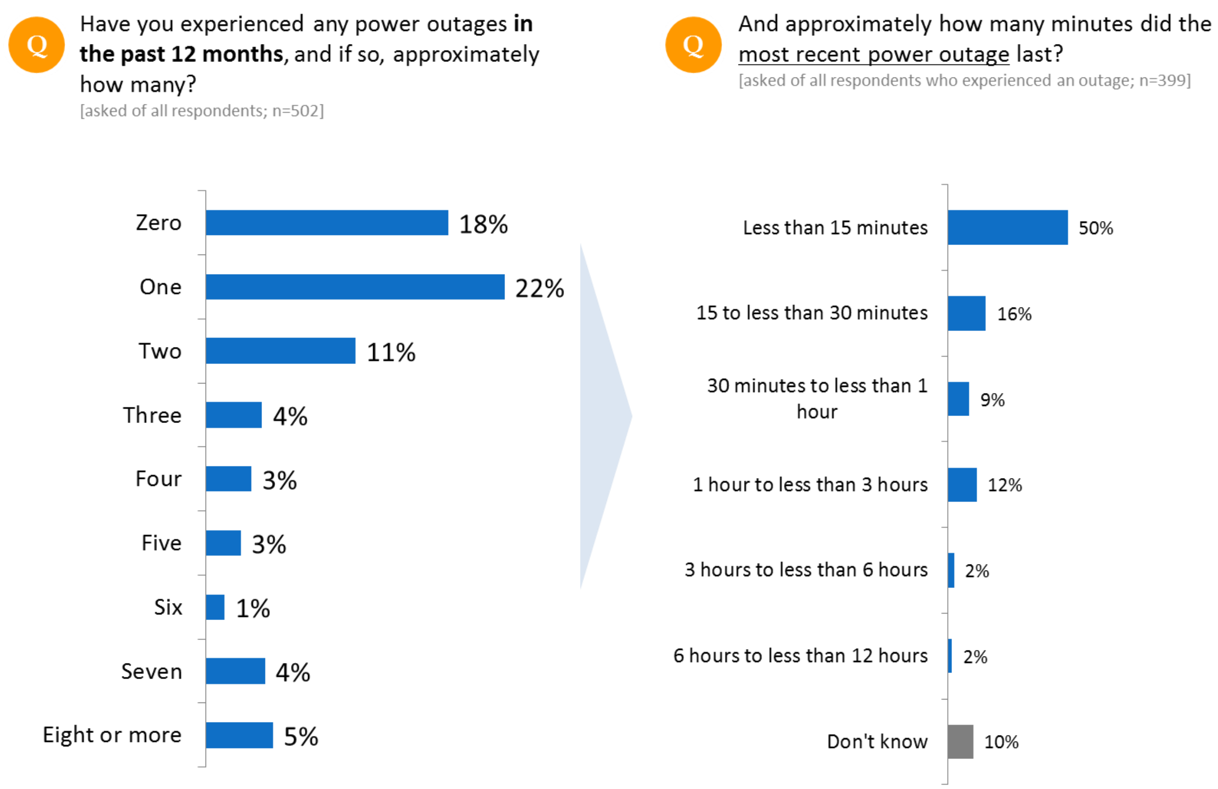
Frequency and Duration of Outages

Customers were first asked how many outages they had experienced in the past year. Those who did experience an outage were then asked how long they were without power.

A plurality of residential customers (22%) experienced one outage in the 12 months prior. Zero outages (18%) were the second most common response, followed by two outages (11%).

For half (50%) of those who had experienced an outage, the most recent one lasted *less than 15 minutes*. 16% experienced an outage lasting between 15 and 30 minutes, while 12% experienced an outage last between one and three hours.

Figure RS.6: Frequency and Duration of Outages

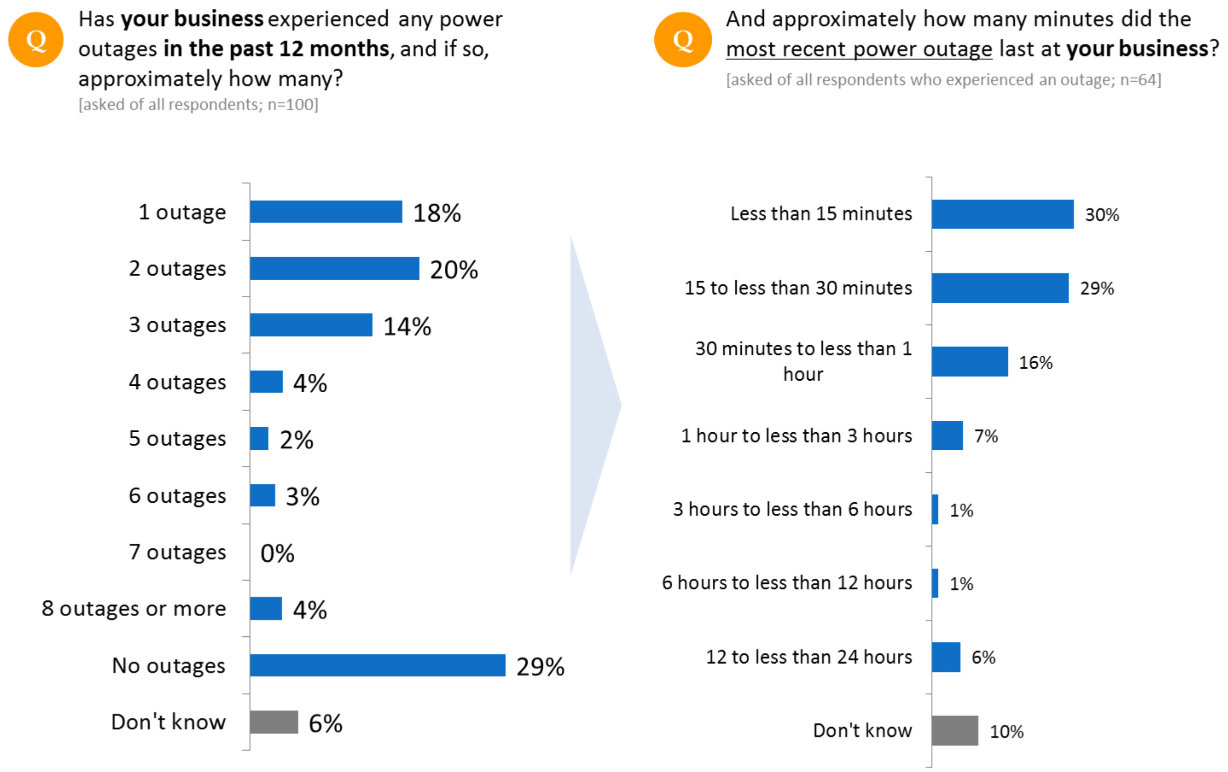


Note: 'Don't know' (5%) not shown

Three-in-ten (29%) of General Service customers report having experienced zero power outages in the twelve months prior. Two-in-ten experienced one (20%) and 15% experienced two outages.

Most commonly, General Service customers report the most recent outage at their business lasting either *less than 15 minutes* (30%), or *15 minutes to less than 30 minutes* (29%. 16% report an outage last between thirty minutes and one hour.

Figure GS.6: Frequency and Duration of Outages



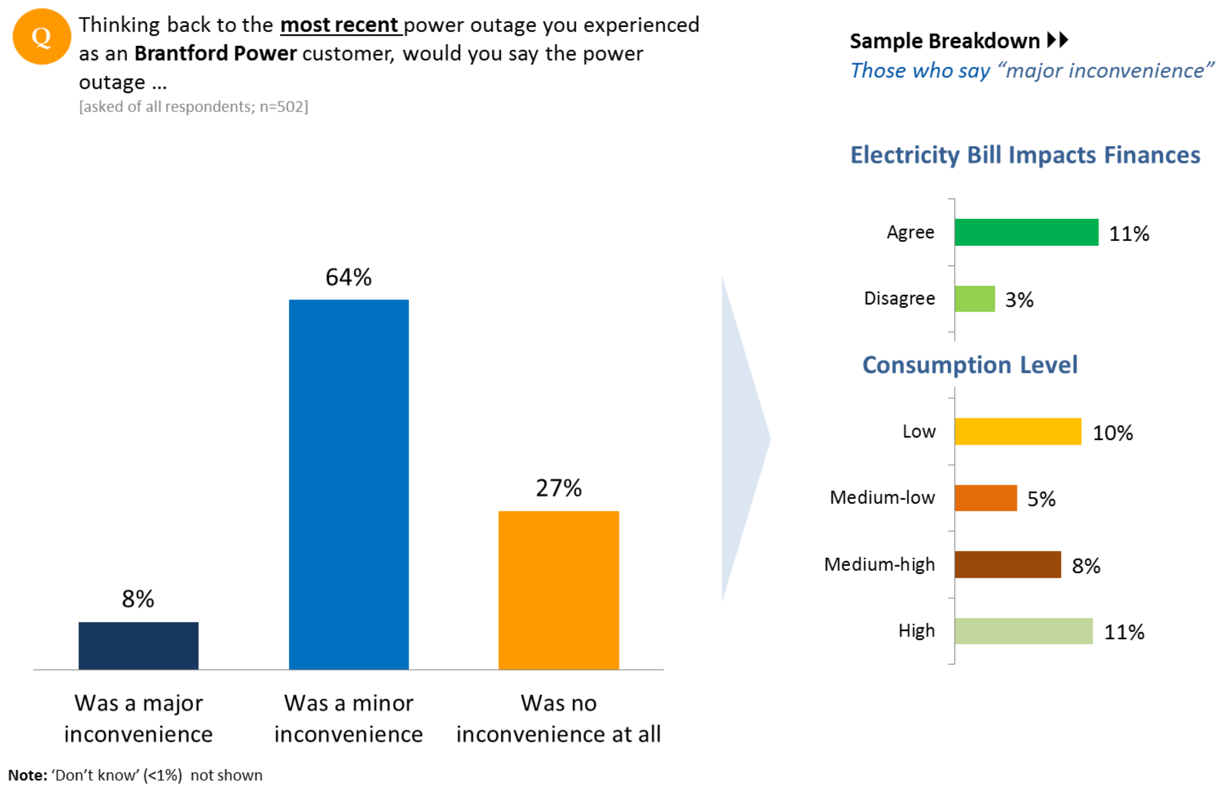
Note: 'Refused' (1%) not shown

Impact of Outages

All customers were asked to think back to the most recent outage that they had experienced, and evaluate the inconvenience it created. Two-thirds (64%) of residential customers say that it *was a minor inconvenience*, while 27% say it *was no inconvenience at all*.

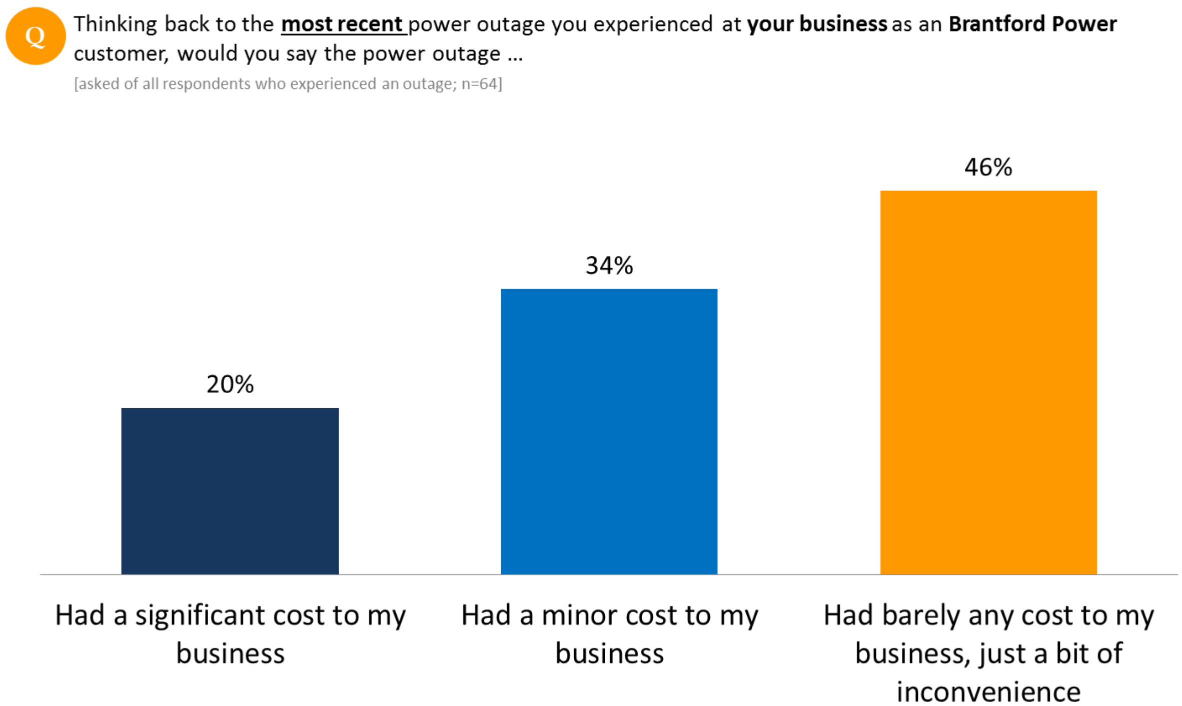
- 11% of those who are financially strained say that the most recent outage *was a major inconvenience;* this is the case for only 3% of those who are not strained.

Figure RS.7: Impact of Outages



Two-in-ten (20%) General Service customers say that the most recent outage they had experienced *had a significant cost to their business*. One-third (33%) say that it *had a minor cost to their business*, while the plurality (46%) say that it *had barely any cost to their business, just a bit of inconvenience*.

Figure GS.7: Impact of Outages



System Reliability Satisfaction

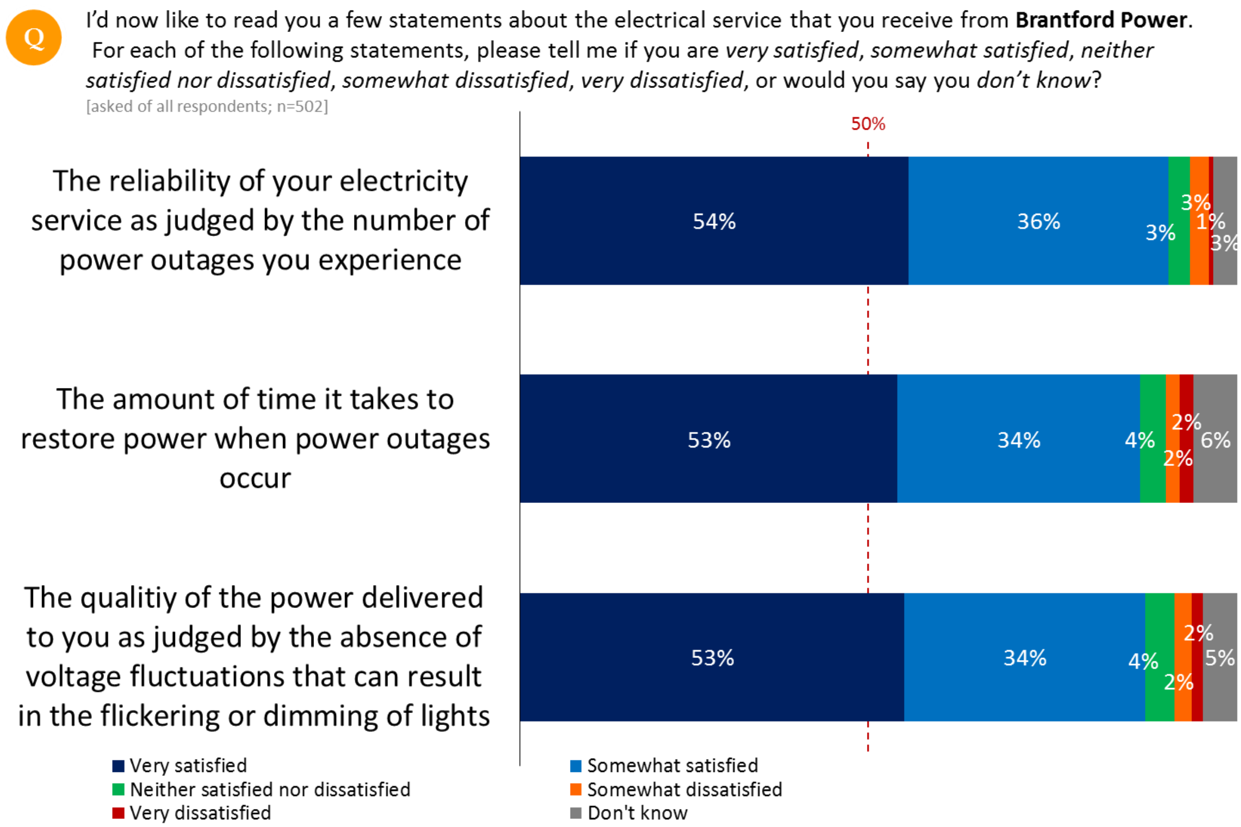
Customers were asked a battery of questions in order to determine their satisfaction with various aspects of the system reliability.

Approximately nine-in-ten (90%) of residential customers are satisfied with each measure.

When viewed in terms of the number of power outages customers experience 90% of customers are satisfied.

When viewed in terms of the amount of time it takes to restore power and the quality of power as judged by the absence of voltage fluctuations 87% of customers are satisfied.

Figure RS.8: System Reliability Satisfaction

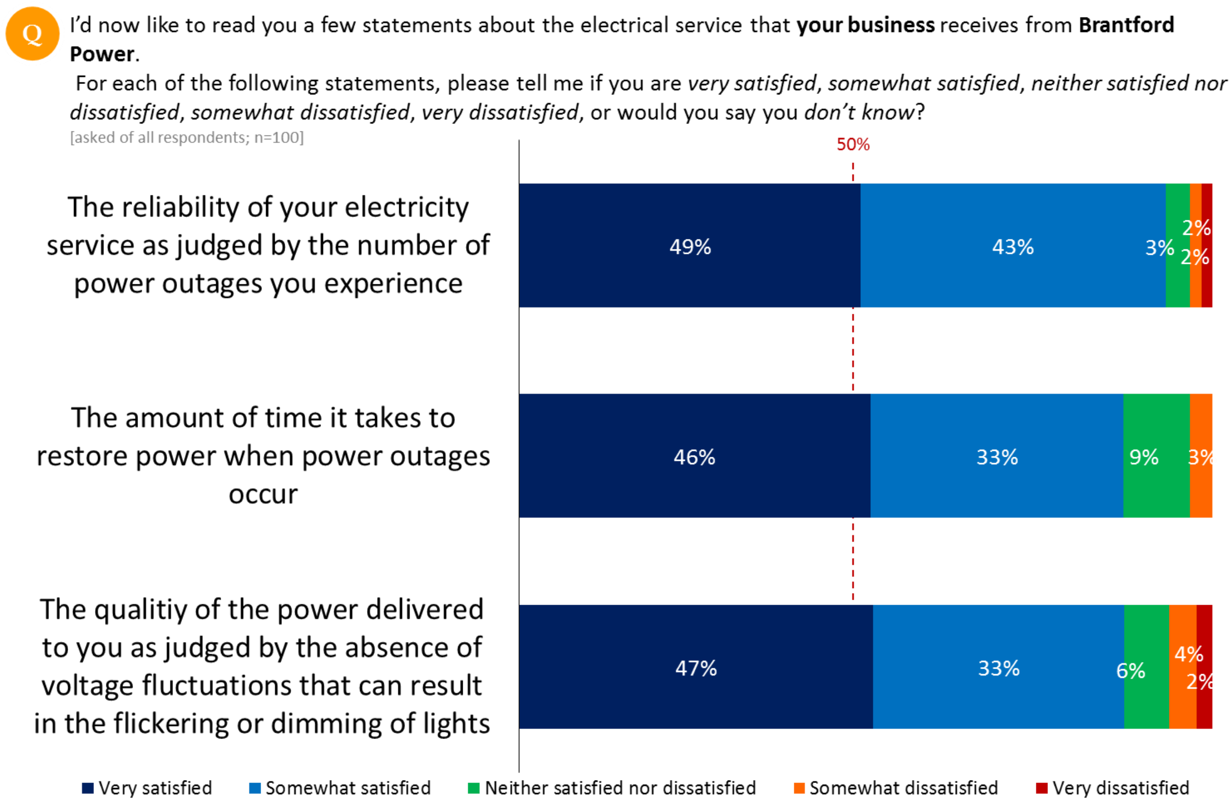


General Service customers are also highly satisfied with all three measures of system reliability.

Judging by the number of power outages they experience, 92% are satisfied with the reliability of their electricity service.

Four-in-five (80%) of General Service customers are satisfied with both *the amount of time it takes to restore power when power outages occur*, and *the quality of the power delivered to you as judged by the absence of voltage fluctuations that can result in the flickering or dimming of lights.*

Figure GS.8: System Reliability Satisfaction

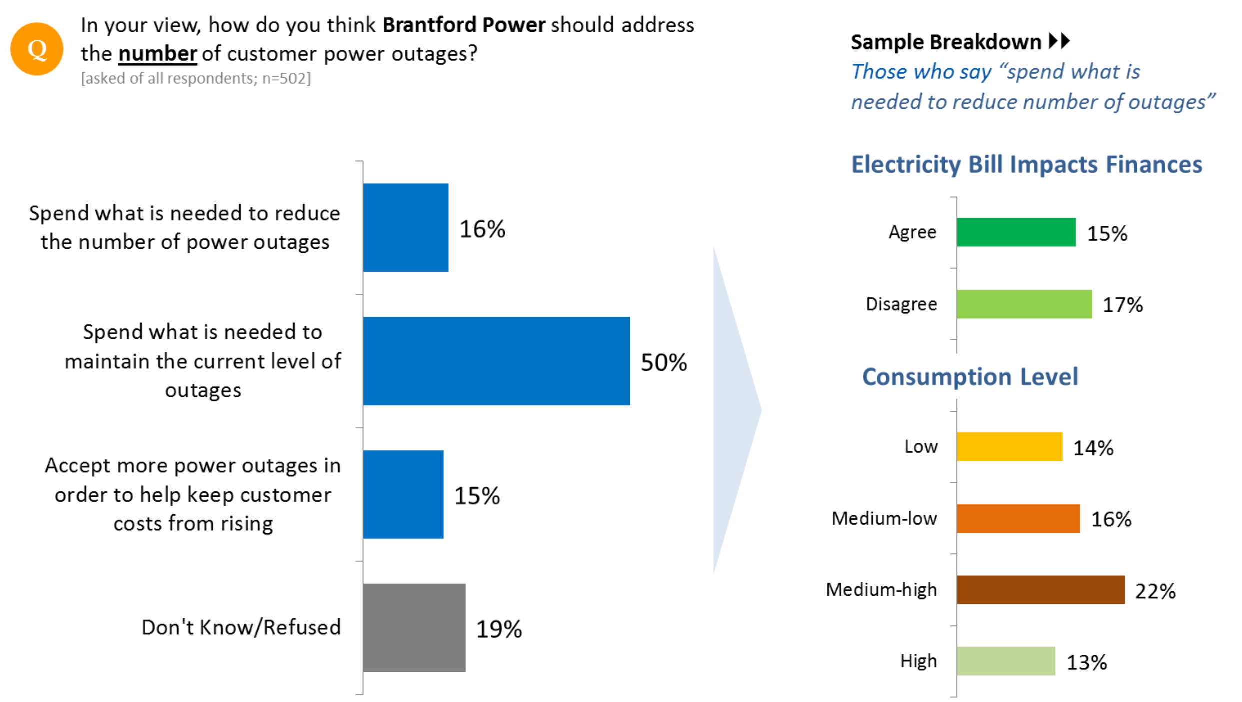


Addressing the Frequency of Power Outages

When it comes to addressing the number of outages, half (50%) of residential customers feel that Brantford Power customers should *spend what is needed to maintain the current level of outages*.

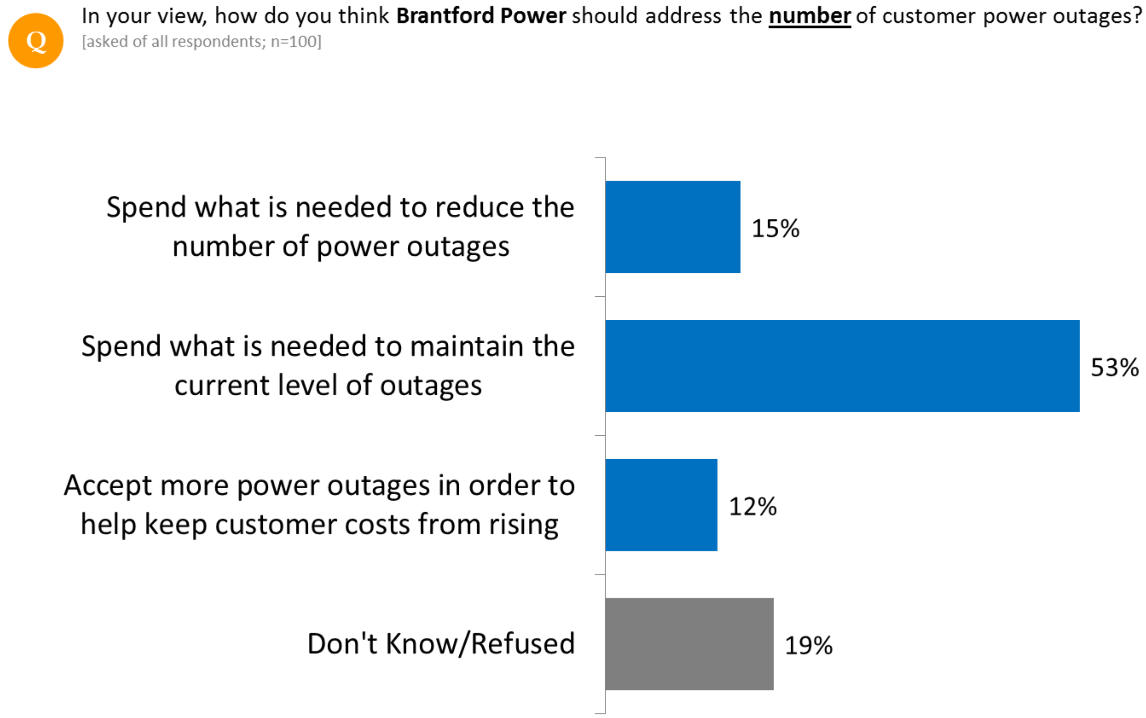
- Medium-high consumption customers are the most apt to say that Brantford power should *spend what is needed to reduce the number the number of power outages* (22%).

Figure RS.9: Addressing the Frequency of Power Outages



In order to address the number of outages, half (53%) of General Service customers feel that Brantford Power should *spend what is needed to maintain the current level of outages*. 15% feel that they *should spend what is needed to reduce the number of outages*, while one-in-ten (12%) would be willing to *accept more power outages in order to help customer costs from rising.*

Figure GS.9: Addressing the Frequency of Power Outages



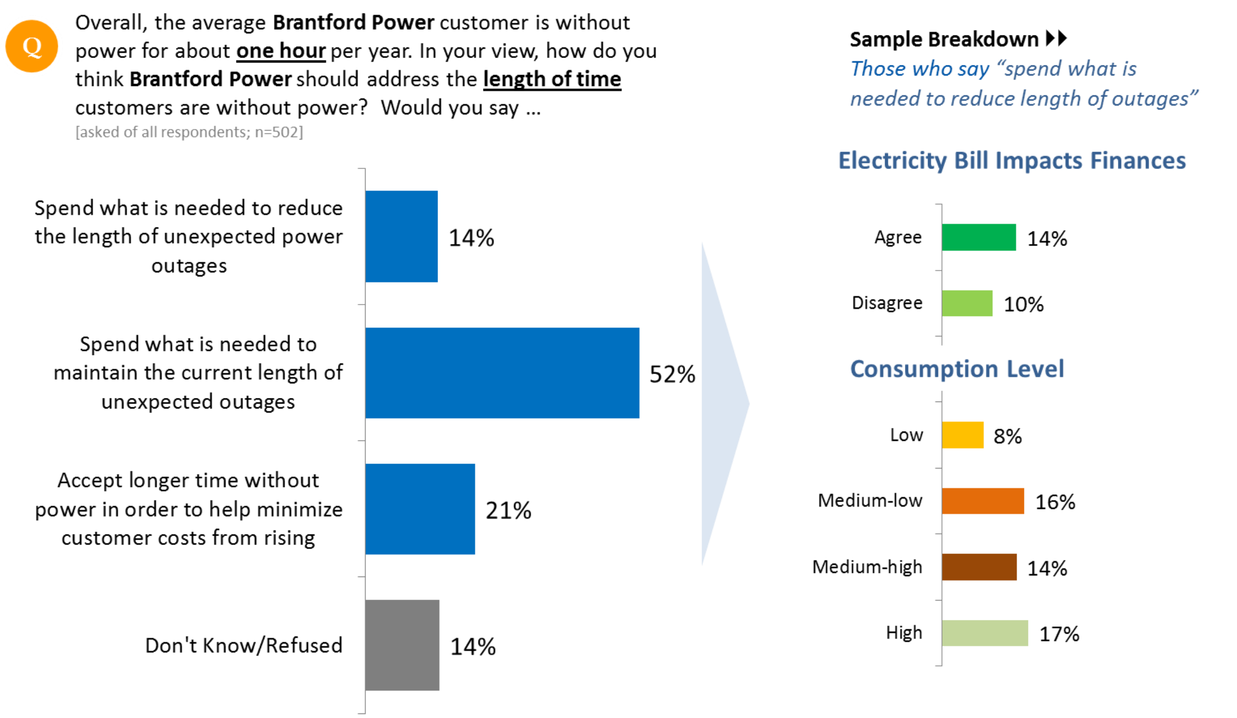
Note: 'Refused' (1%) not shown

Addressing the Duration of Power Outages

After having been informed that the average Brantford Power customer is without power for one hour, 52% of residential customers say that they should *spend what is needed to maintain the current length of unexpected outages.* Two-in-ten (21%) would *accept longer time without power in order to help minimize customer costs from rising*.

- Customers that are more impacted by their bills (14%) are slightly more apt than those who are not (10%) to say Brantford power *should spend what is needed to reduce the length of unexpected outages.*

Figure RS.10: Addressing the Duration of Outages

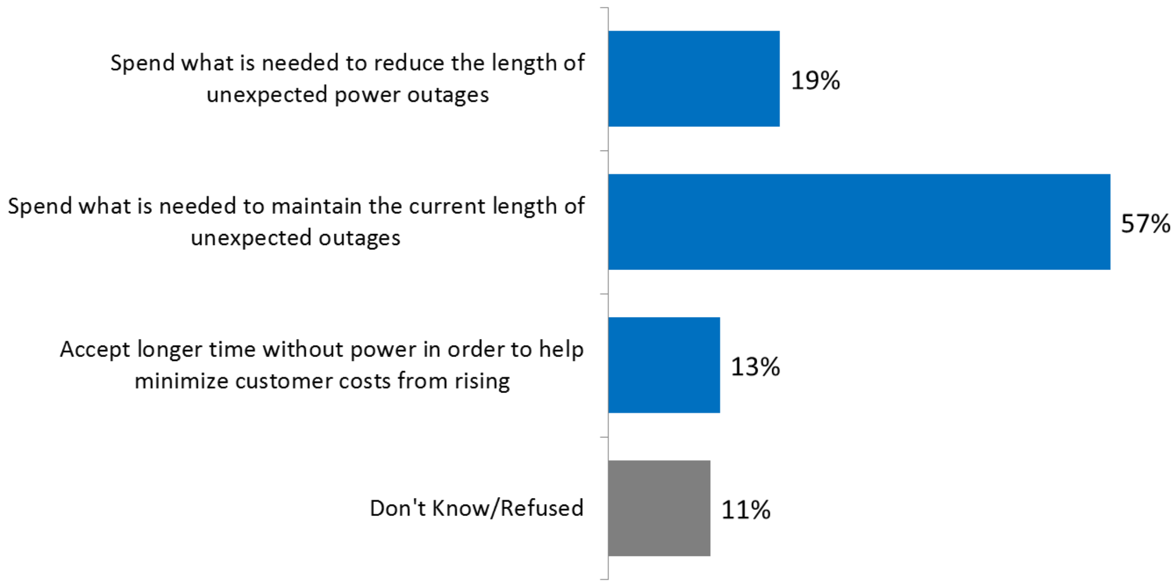


In regard to addressing the length of time customers are without power, the majority (57%) of General Service customers are in favour of maintaining the status quo. 19% would have Brantford Power *spend what is needed to reduce the length of unexpected power outages*, while 13% *would accept longer time without power in order to help minimize customer costs from rising.*

Figure GS.10: Addressing the Duration of Outages

Q Overall, the average **Brantford Power** customer is without power for about **one hour** per year. In your view, how do you think **Brantford Power** should address the **length of time** customers are without power? Would you say …

[asked of all respondents; n=100]



System Challenges & Priorities

This section explores respondents' preferences on various aspects of Brantford Power's Capital Investment plan and OM&A spending, including perspectives on conservation and demand management programs, and facility relocation.

System Challenges & Priorities Summary

Investment in Aging Infrastructure

Half (50%) of residential and General Service (51%) customers feel that Brantford Power should invest *what it takes to replace the system's aging infrastructure to maintain system reliability; even if that increases their monthly electricity bill by less than a dollar over the next few years.*

Replacing Aging Infrastructure

79% of residential and 76% of General Service customers feel that it is important for Brantford Power to invest now in modernizing the grid.

Conservation and Demand Management

Two-in-five (41%) residential and 36% of General Service customers currently participate in a Brantford Power conservation program.

Looking forward, three-quarters of residential (74%) and General Service (73%) are likely to participate in a conservation program, and 30% are *somewhat likely*.

Four-in-five (81%) residential and 64% of General Service customers think that Brantford Power does a good job at providing them with information on available tools and programs that can help them manage their household electricity consumption.

Facility Relocation

Buying a new facility that will meet current and foreseeable future needs (43% residential; 39% General Service) is the most commonly suggested solution for facility relocation. This is followed by *building a new facility* (17%) for residential customers, and *finding a new rental space to house equipment and staff* (22%) for General Service customers.

Preamble for System Challenges & Priorities Section

The following introduces the 'System Challenges and Priorities' section of the survey and was read to both **residential** and **General Service** customers:

*"While **Brantford Power** believes it has done its best to prolong the life of the assets that make up the distribution system, many of these assets are approaching the end of their useful life.*

*As part of its investment plan, **Brantford Power** is proposing a significant infrastructure replacement or renewal program. The estimated cost of this system renewal program is **<u>$3.4 million</u>** between 2017 and 2021.*

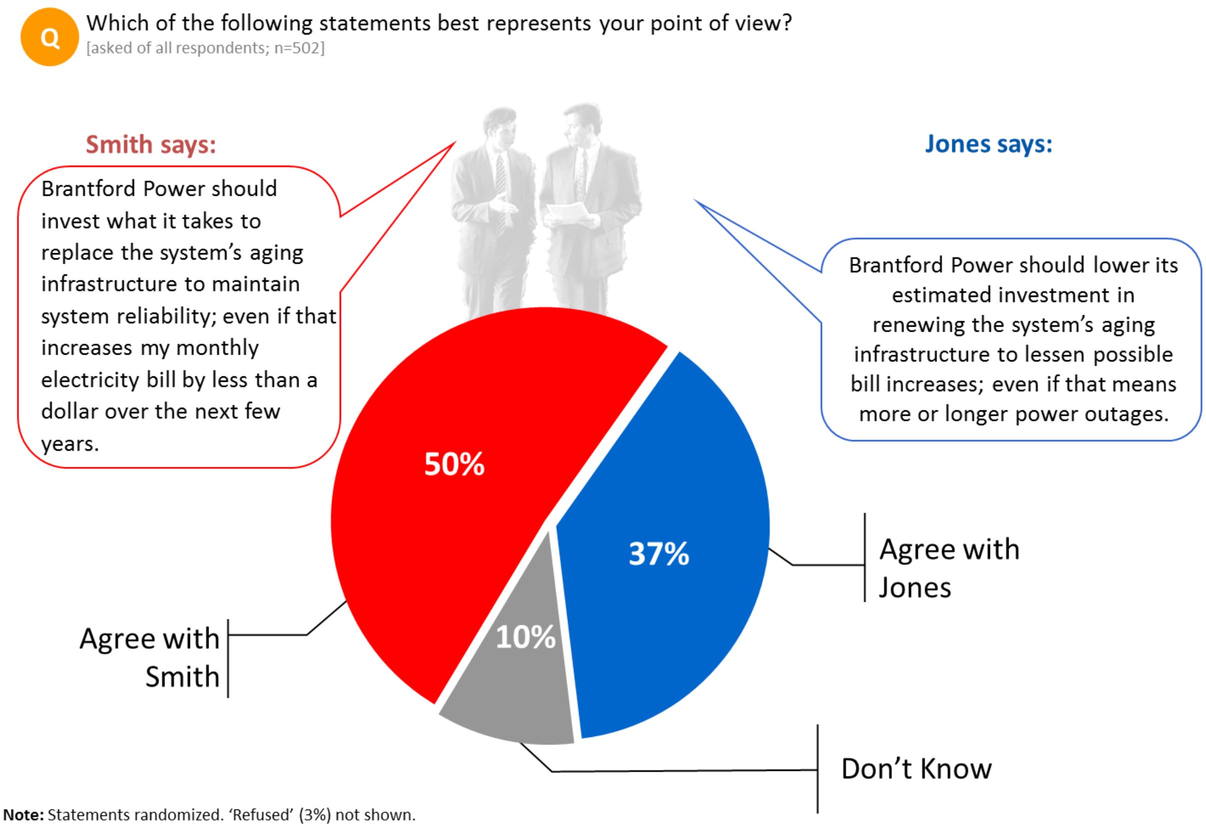
*Although this plan will allow **Brantford Power** to make the necessary investments to maintain system reliability, **<u>it will have an impact on customer bills</u>**."*

Investment in Aging Infrastructure

Half (50%) of residential customers feel that *Brantford Power should invest what it takes to replace the system's aging infrastructure to maintain system reliability; even if that increases their monthly electricity bill by less than a dollar over the next few years.*

37% feel that *Brantford Power should lower its estimated investment in renewing the system's aging infrastructure to lessen possible bill increases; even if that means more or longer power outages.*

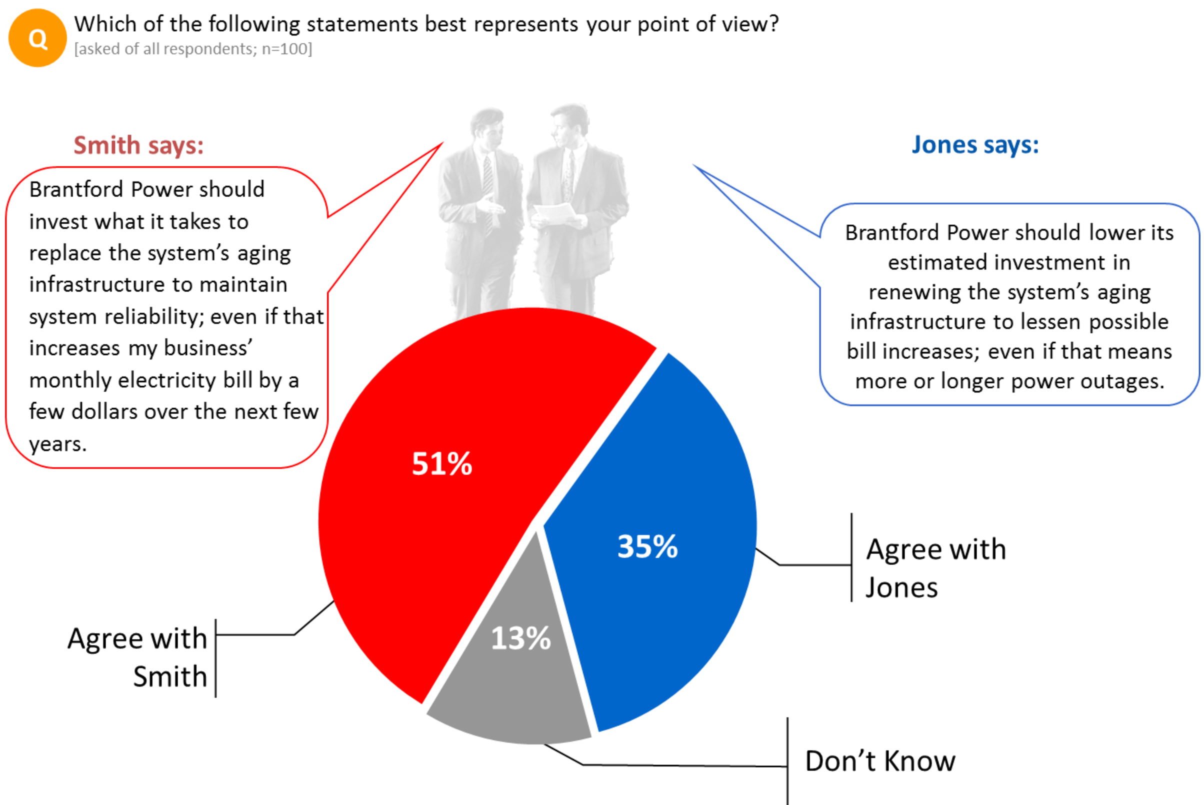
Figure RS.11: Investment in Aging Infrastructure



Note: Statements randomized. 'Refused' (3%) not shown.

Half (51%) of General Service customers feel that *Brantford Power should invest what it takes to replace the system's aging infrastructure to main system reliability; even if that increases their monthly electricity bill by few dollars over the next few years.* 35% feel that *Brantford Power should lower its estimated investment in renewing the system's aging infrastructure to less possible bill increases; even if that means more or longer power outages.* 13% say *don't know*.

Figure GS.11: Investment in Aging Infrastructure



Note: Statements randomized. 'Refused' (2%) not shown.

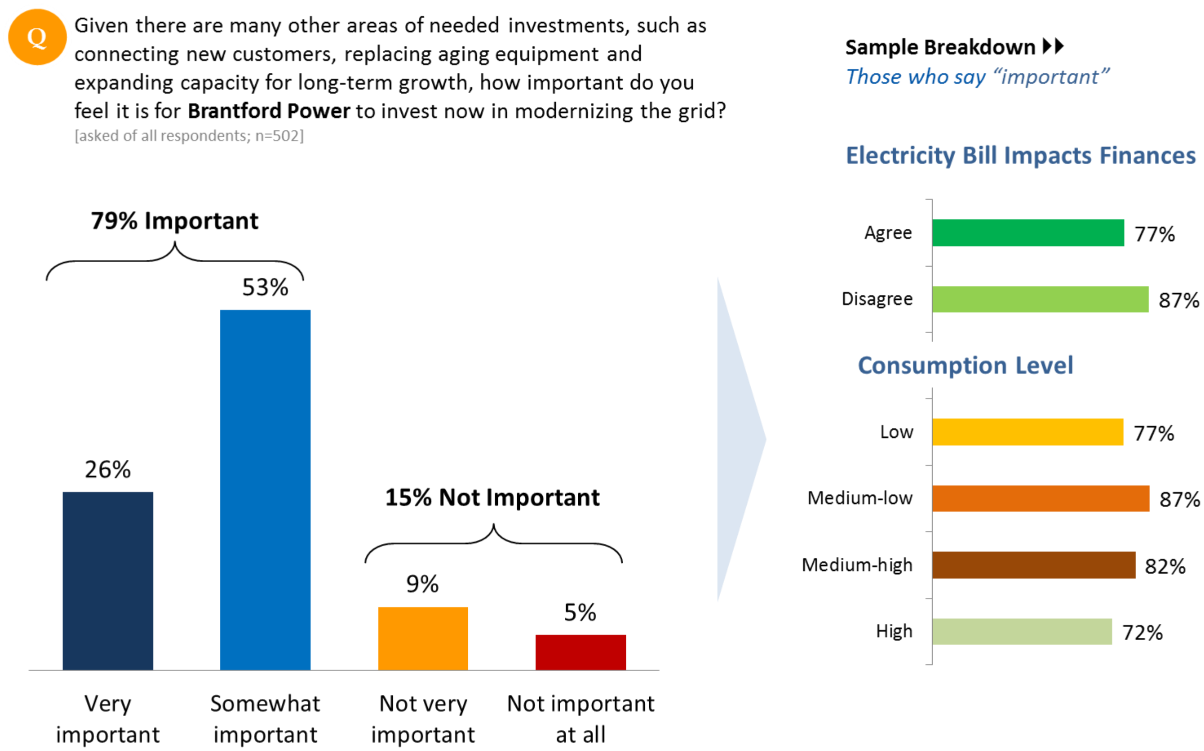
Investment in Modernization

> The following preamble introduces the question on modernizing the grid, and was read to both **residential** and **General Service** customers:
>
> *"Modernizing the grid can allow **Brantford Power** to improve reliability. Investments such as automated switches may allow **Brantford Power** to quickly identify the location of outages in order to minimize the number of people impacted by outages and to restore electricity to customers more quickly than was previously possible."*

Following this brief preamble, residential customers were asked how important they feel it is for Brantford Power to invest now in modernizing the grid. Four-in-five (79%) residential customers feel that it is important. One-quarter (26%) say *very important*, while 53% say *somewhat important*.

- High consumption customers (72%) are the least likely to say that it is important to invest now in modernizing the grid.

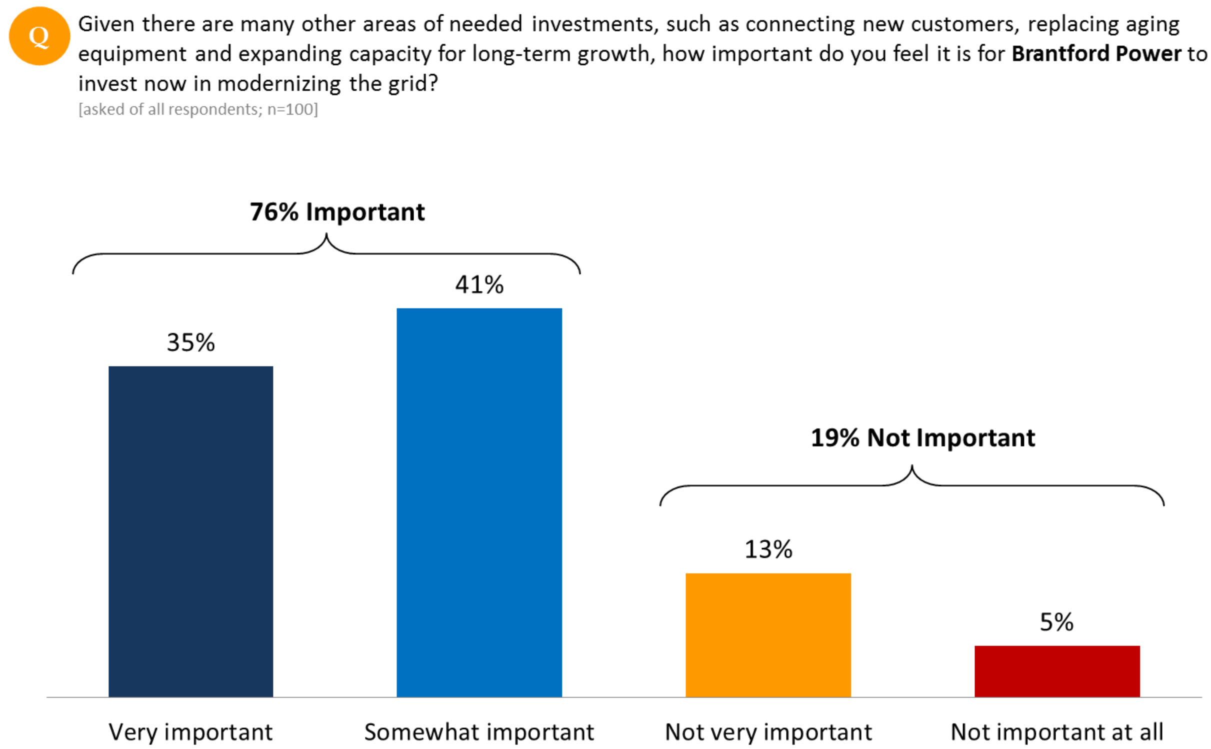
Figure RS.12: Replacing Aging Infrastructure



Note: 'Don't know'/'Refused' (6%) not shown

Three-quarters (76%) feel that it is import for Brantford Power to invest now in modernizing the grid. 35% of these say *very important,* while 41% say *somewhat important.* Two-in-ten (19%) feel that it is not important.

Figure GS.12: Replacing Aging Infrastructure



Note: 'Don't know' (4%) and 'Refused' (1%) not shown

Conservation and Demand Management

The following preamble introduces the section on conservation and demand management, and was read to both **residential** and **General Service** customers:

*"One of the most cost effective ways for **Brantford Power** to reduce its required investments in the distribution system is through customer uptake of conservation programs.*

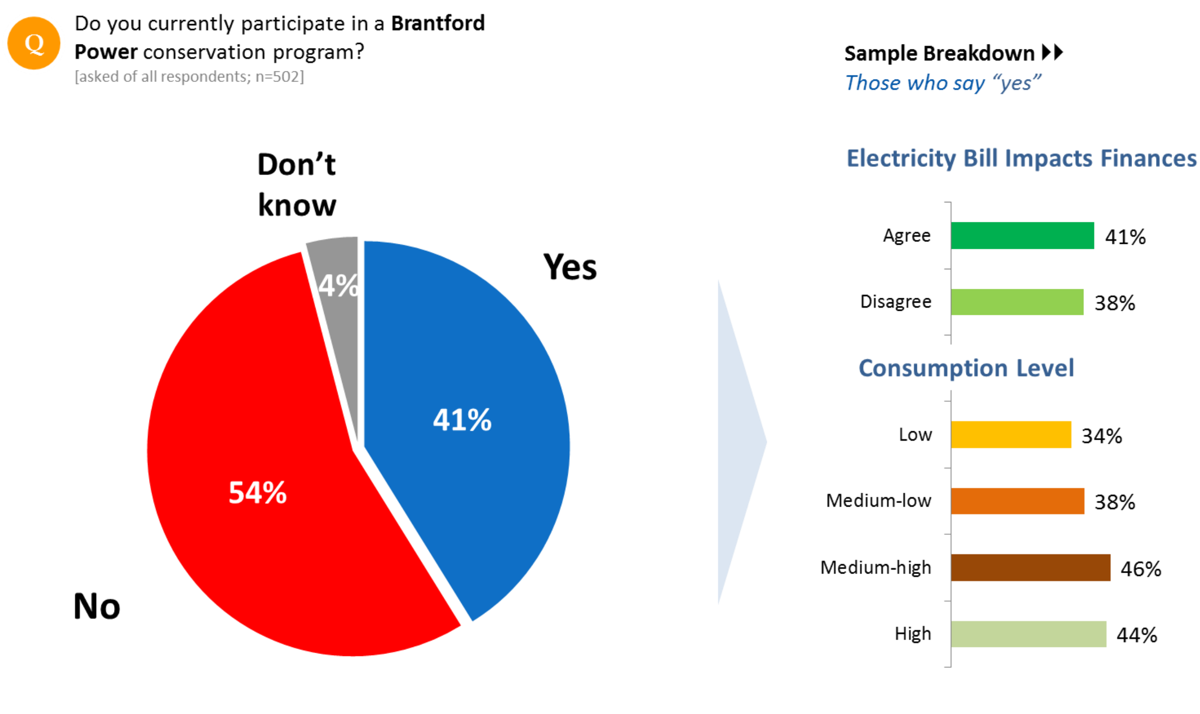
*When customers consume less electricity at peak demand times, less strain is put on the distribution system and as a result, customers save money in two ways: 1) a lower level of investment is required by **Brantford Power** to expand and maintain the distribution system's capacity to deliver electricity; and 2) customers pay less when they reduce their electricity consumption."*

Conservation and Demand Management Program Participation

4-in-10 (41%) residential customers believe they currently participate in a Brantford Power conservation program. Over half (54%) do not, and 4% don't know.

- A greater proportion of higher consumption customers (medium-high: 46%; high: (44%) than lower consumption customers (low: 34%; medium-low: 38%) currently participate in these programs.

Figure RS.13: CDM Program Participation

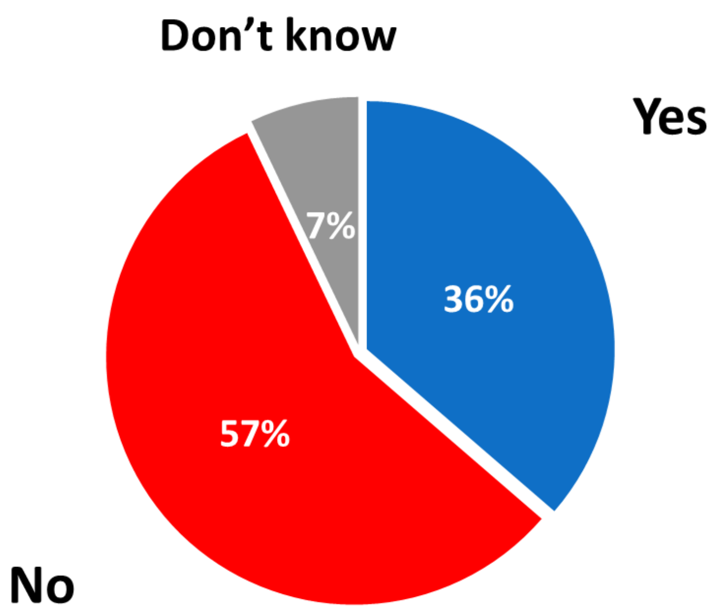


Note: 'Refused' (1%) not shown

The majority (57%) of General Service customers do not currently participate in a Brantford Power conservation program. 36% of General Service customers currently do participate, while 7% don't know.

Figure GS.13: CDM Program Participation

Has **your business** ever participated in a **Brantford Power** conservation program?
[asked of all respondents; n=100]

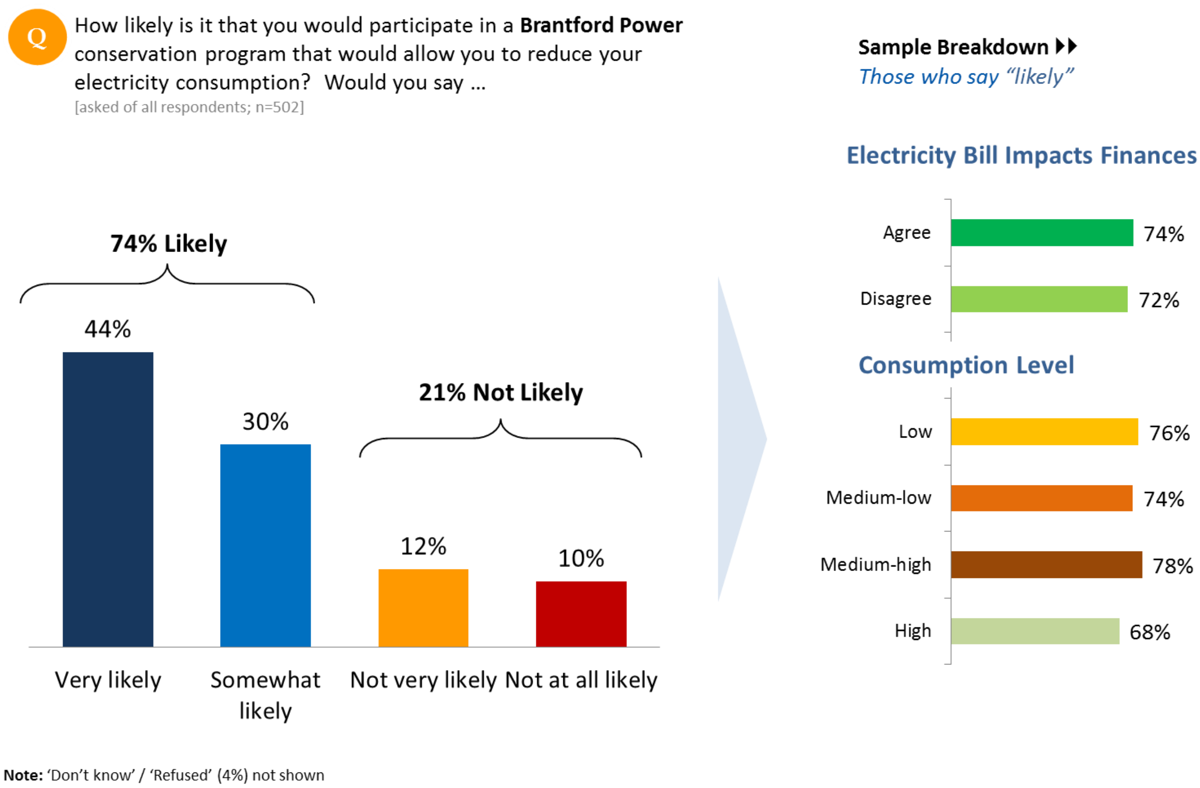


Future Conservation and Demand Management Participation

Three-in-four (74%) residential customers are likely to participate in a Brantford Power conservation program that would allow them to reduce their electricity consumption. This is broken down into 44% who say *very likely* and 30% who say *somewhat likely.* One-in-five (21%) are not likely to participate.

- High consumption (68%) customers are least likely to participate in such a program.

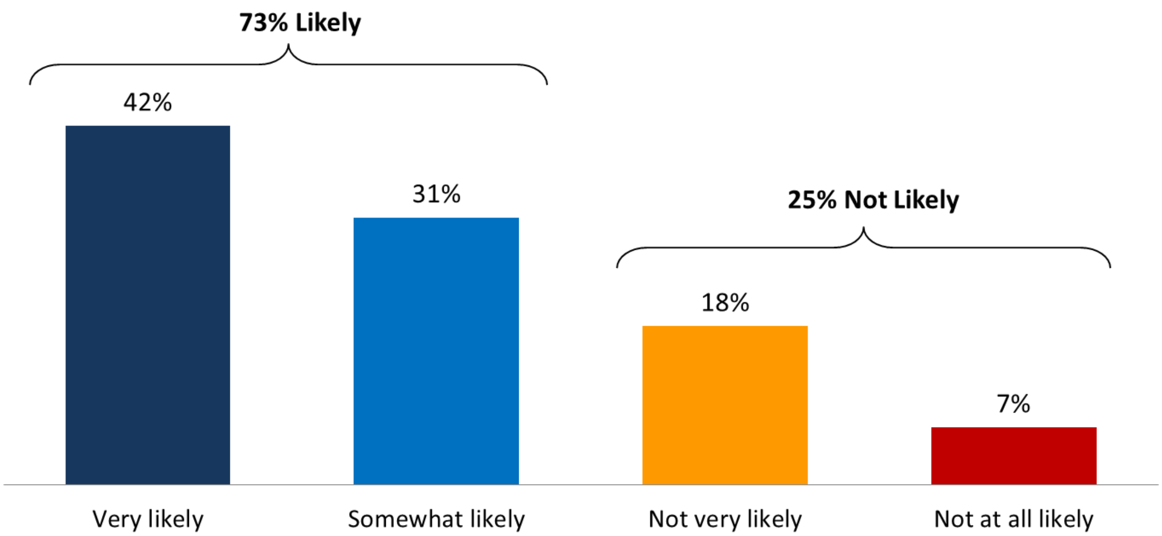
Figure RS.14: Future CDM Participation



Seven-in-ten (73%) of General Service customers say their business is likely to participate in future Brantford Power conservation programs. The plurality (42%) is *very likely*, while 31% are *somewhat likely*. One-quarter (25%) are not likely to participate.

Figure GS.14: Future CDM Participation

Q How likely is **your business** to participate in future **Brantford Power** conservation programs that could help reduce your electricity consumption? Would you say …
[asked of all respondents; n=100]

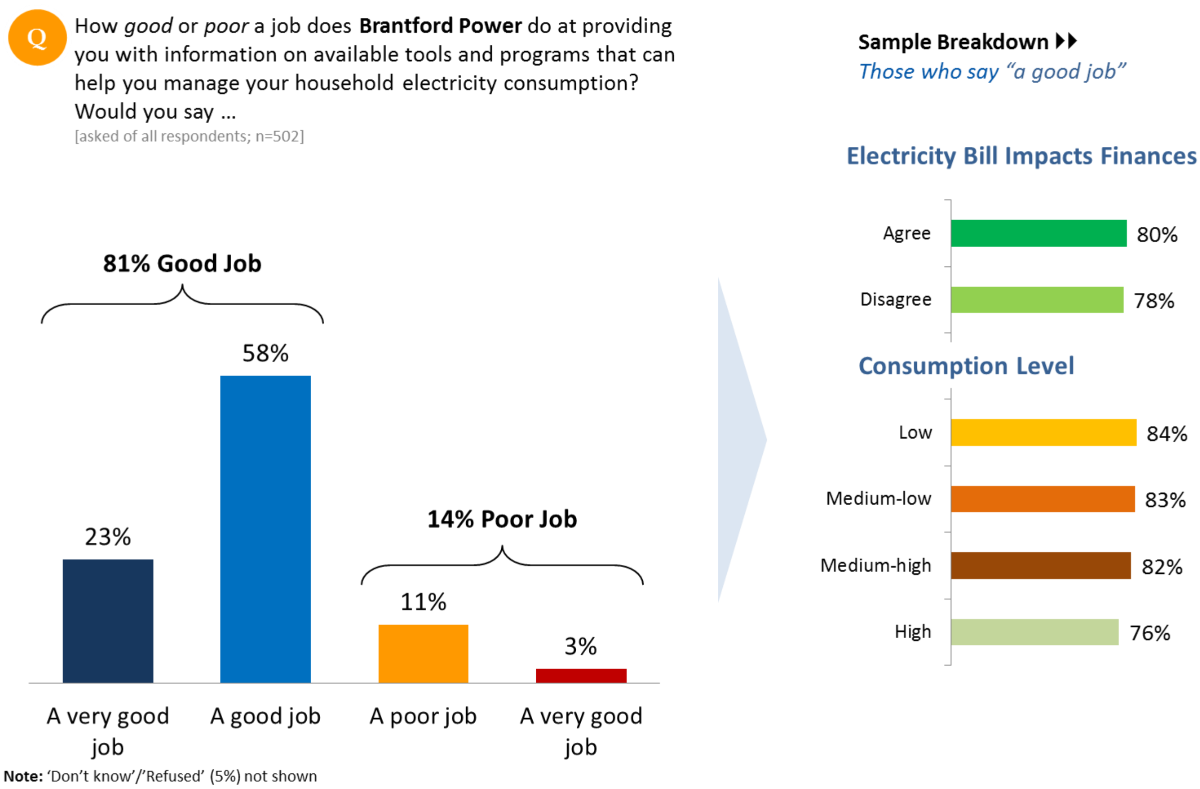


Note: 'Don't know' (2%) not shown

Providing Information on Tools and Programs

Customers were asked to rate how Brantford Power does at providing information on available tools and programs that can help manage household electricity consumption. Among residential customers, 8-in-10 (81%) feel that a good job is being done, while only 14% feel that Brantford Power is doing a poor job.

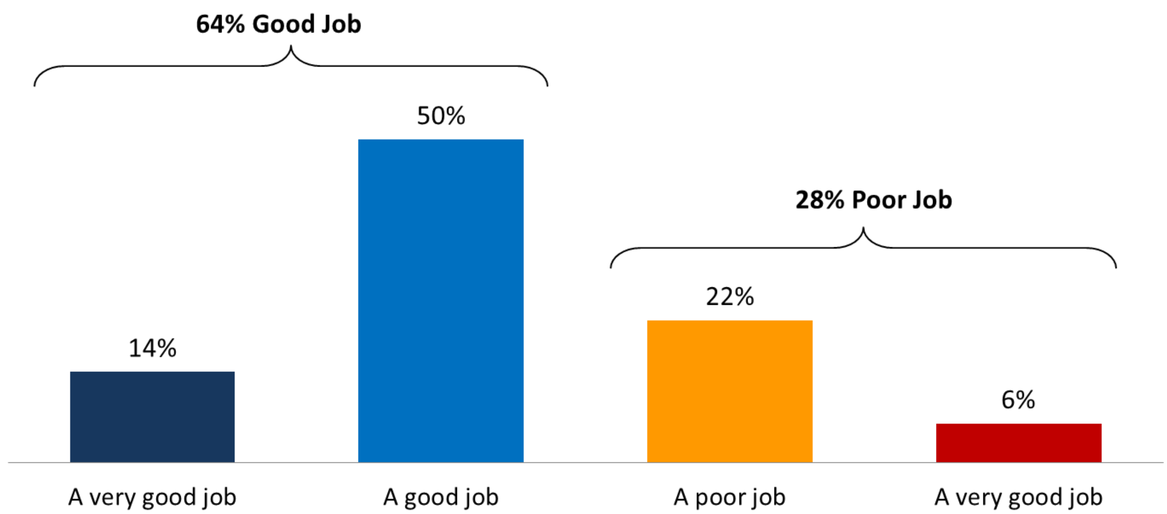
Figure RS.15: Providing Information on Tools and Programs



General Service customers feel less informed than residential customers. Half (50%) say Brantford Power is doing *a good job* and 14% say *a very good job*, for a total of 64%. Three-in-ten (28%) feel Brantford Power is doing a poor job at providing their businesses with information on available tools and programs to help them manage their organization's electricity consumption.

Figure GS.15: Providing Information on Tools and Programs

Q How *good* or *poor* a job does **Brantford Power** do at providing **your business** with information on available tools and programs that can help you manage your **organization's** electricity consumption? Would you say …
[asked of all respondents; n=100]



Note: 'Don't know' (7%) and 'Refused' (1%) not shown

Facility Relocation

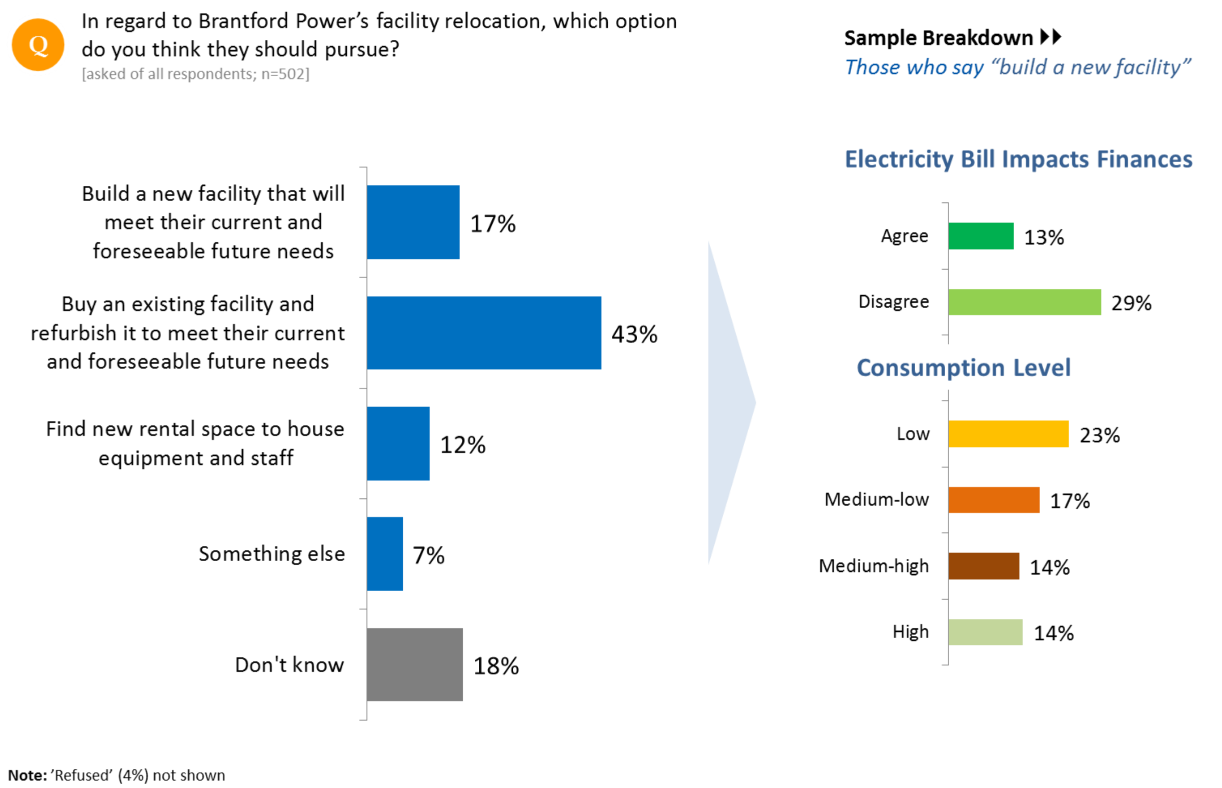
The following preamble introduces the question on facility relocation, and was read to both **residential** and **General Service** customers:

"At some point over the next 5 years, Brantford Power will have to relocate from the 3 separate buildings currently rented from the City of Brantford. Brantford Power will consider its options for a consolidated location to accommodate all of its staff and equipment. ***Brantford Power*** *has currently allocated* ***$15.4 million*** *for this facility relocation."*

Residential customers were asked which course of action they think Brantford Power should pursue in regards to their planned facility relocation. The plurality (43%) think that Brantford Power should *buy and existing facility and refurbish it to meet their current needs and foreseeable future needs.* 17% feel that it would be better to *build a new facility*, and just over one-in-ten (12%) think that Brantford power should *find new rental space to house equipment and staff*.

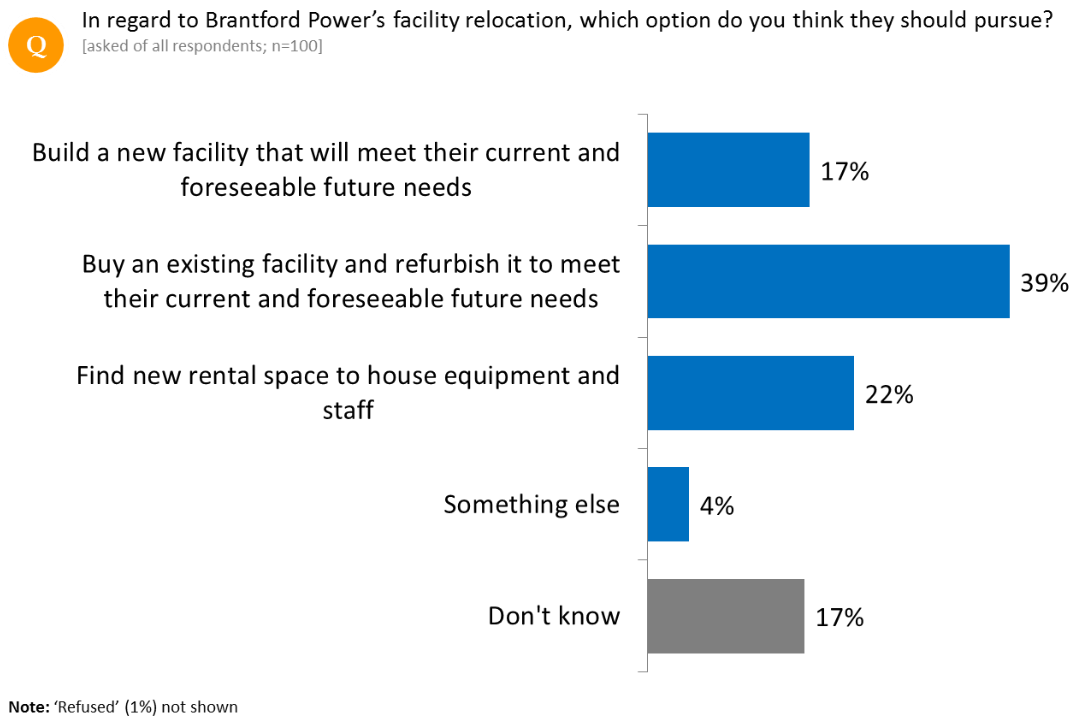
- Low consumption (23%) customers, and those who are not financially strained (29%), are most likely to say *build a new facility*.

Figure RS.16: Facility Relocation



While still divided, General Service customers are also most in favour in favour of *buying an existing facility* (39%). *Finding a new rental space to house equipment and staff* was the second most favourable option, gaining support from 22%, while *building a new facility* is support by 17%.

Figure GS.16: Facility Relocation



Reaction to Previous Customer Consultation Input

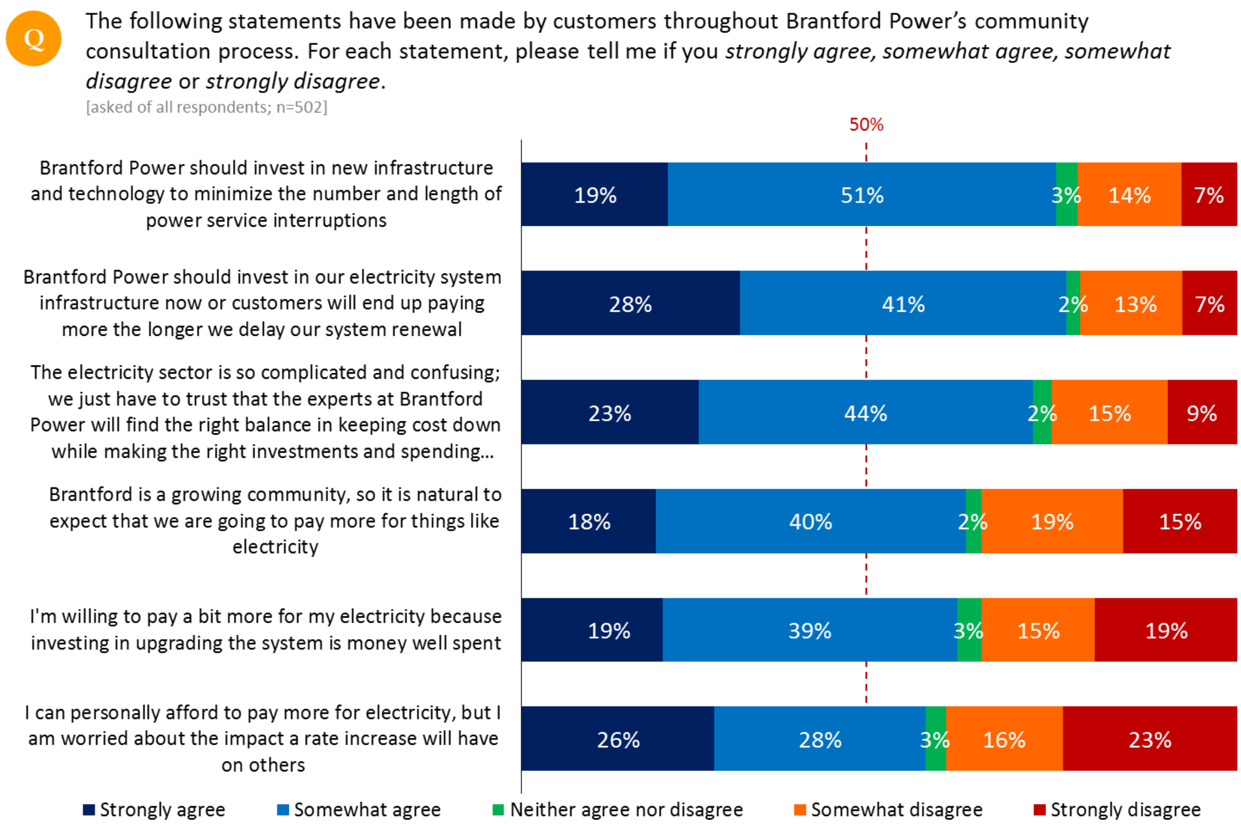
This section measures agreement with some of the key opinion statements provided by Brantford Power's customers in previous phases of the consultation. There were a total of six customer statements in the survey.

Customer Reaction Statements

The majority of residential customers agree with each of the statement.

- Customers most agree (70%) that "Brantford Power should invest in new infrastructure and technology to minimize the number and length of power service interruptions."
- The fewest customers (54%) agree that "I can personally afford to pay more for electricity, but I am worried about the impact a rate increase will have on others."
- 67% of customers feel that the electricity system is complicated and confusing and decision making should be left to the professionals at Brantford Power.

Figure RS.17: Reaction to Customer Input

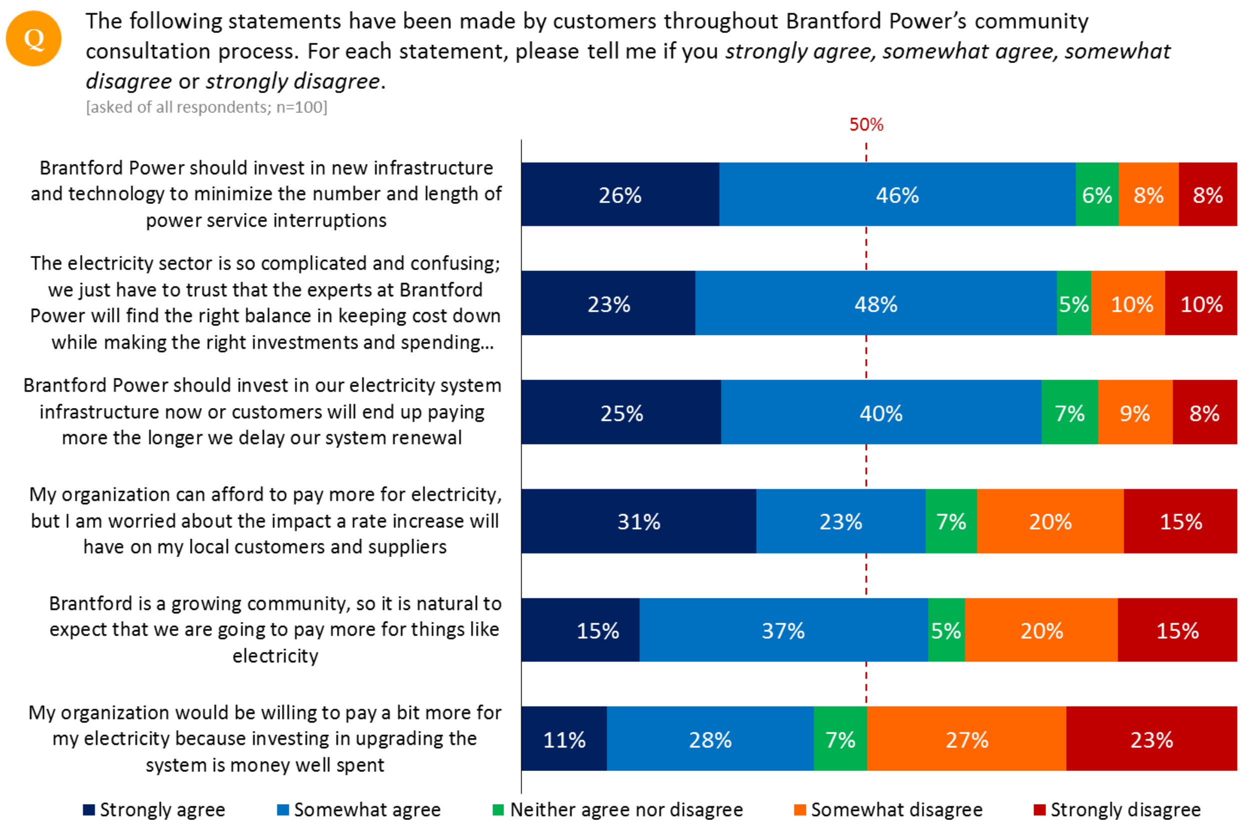


Customer Reaction Statements

The majority of General Service customers agree with five of the six statements.

- *Investing in new infrastructure and technology to minimize the number and length of power service interruptions* is the most agreed upon statement (72%).
- This is followed closely by the impression that *the electricity is so complicated and confusing* that customers have to just trust the experts at Brantford Power (71%).
- The only statement not agreed upon by the majority of General Service customers is in regard to increasing cost. 39% of General Service customers *would be willing to pay a bit more for their electricity because investing in upgrading the system is money well spent.*

Figure GS.17: Reaction to Customer Input



Assessment of Plan

In this next section, respondents were assessed on their acceptance of the plan: do they support the rate increase and why or why not? "Acceptance" refers to those who either think the rates are reasonable and support the plan or don't like the plan, but think it is necessary.

Acceptance of Rate Increase Summary

Two-in-three (65%) residential customers give permission for the proposed rate increase. 28% support the increase outright, while 37% don't like it, but think the rate increase is necessary. Three-in-ten (29%) feel that the rate increase is unreasonable and oppose it.

- Financially strained households (55%) are much less likely to support the rate increase than those that are not (84%).
- Support decreases as consumption level increase (low: 70%; medium-low: 68%; medium-high: 63%; high: 57%).

68% of General Service customers give permission for the proposed rate increase. Two-in-ten (20%) support the increase outright, and almost half (48%) don't like it but think that it is necessary

Opinions on Proposed Rate Increase

The following reasons were given by residential customers for holding their opinions:

- *The rate increase is reasonable and I support it*: Four-in-ten (39%) say it's necessary to invest in the infrastructure in order to avoid greater costs in the future.
- *I don't like it, but I think the rate increase is necessary:* 23% do not like any increase, but concede that this particular increase is necessary.
- *The rate increase is unreasonable and I oppose it:* Two-in-five (38%) say that the increase is too high and they feel that they are already paying a lot.

The following reasons were given by General Service customers for holding their opinions:

- *The rate increase is reasonable and I support it*: Half (51%) say that the increase is necessary, the system needs upgrading and power is a necessity.
- *I don't like it, but I think the rate increase is necessary:* 24% give the same reason as above, while indicating that they do not like the increase.
- *The rate increase is unreasonable and I oppose it:* 73% say that the increase is too costly and they feel that they are already paying a lot.

Financial Flexibility and Level of Acceptance

Those who are more financially impacted are less inclined to support the proposed increase.

- Overall, permission is given by just over half (55%) of residential customers whose households are financially strained, compared to 84% of those who are not.
- General Service customers are more apt to give permission regardless of their financial flexibility (68% strained; 88% not strained).

Preamble for Assessment of Plan Section

Before the Assessment of Plan questions were asked, customers were presented with the following preambles that reflect the impact of the proposed rate increase on their particular rate class:

The **residential** customer preamble read as follows:

*"**Brantford Power** believes that a **proactive** and **consistent** renewal approach is needed to maintain system performance while keeping bill impacts manageable over the longer-term. **Brantford Power's** proposed plan will spend an estimated **$22.8 millio**n on capital investments between 2017 and 2021. This includes …*

- ***$3.4 million** to replace aging infrastructure;*
- ***$9.3 million** to serve the expanding community of Brantford and connect customers to the grid;*
- ***$7.0 million** to invest in equipment and facilities needed to maintain and operate the system; and*
- ***$3.2 million** to add new technologies into the power system.*

*To fund this plan, **Brantford Power** is proposing the **average residential customers' rate increase by approximately $1.14 per month** on the distribution portion of their bill over the next five years. So, in five years, by 2021, the average residential household will be paying an estimated **$5.68 more per month** on the distribution portion of its electricity bill."*

General service customers were read the following preamble:

*"**Brantford Power** believes that proactive renewal and consistent maintenance is needed to maintain system performance, while keeping the impact on customer bills manageable over the long-term. Between 2017 and 2021, **Brantford Power's** proposed plan will see it …*

- *spend an estimated **$54.6 million** on on-going maintenance and the operation of the distribution system; and*
- *invest an estimated **$22.8 million** in new equipment and infrastructure priorities that will help ensure system reliability.*
- *To fund this plan, **Brantford Power** is proposing the **average General Service or small business customers' rate increase by approximately $1.35 per month** on the distribution portion of their bill over the next five years.*

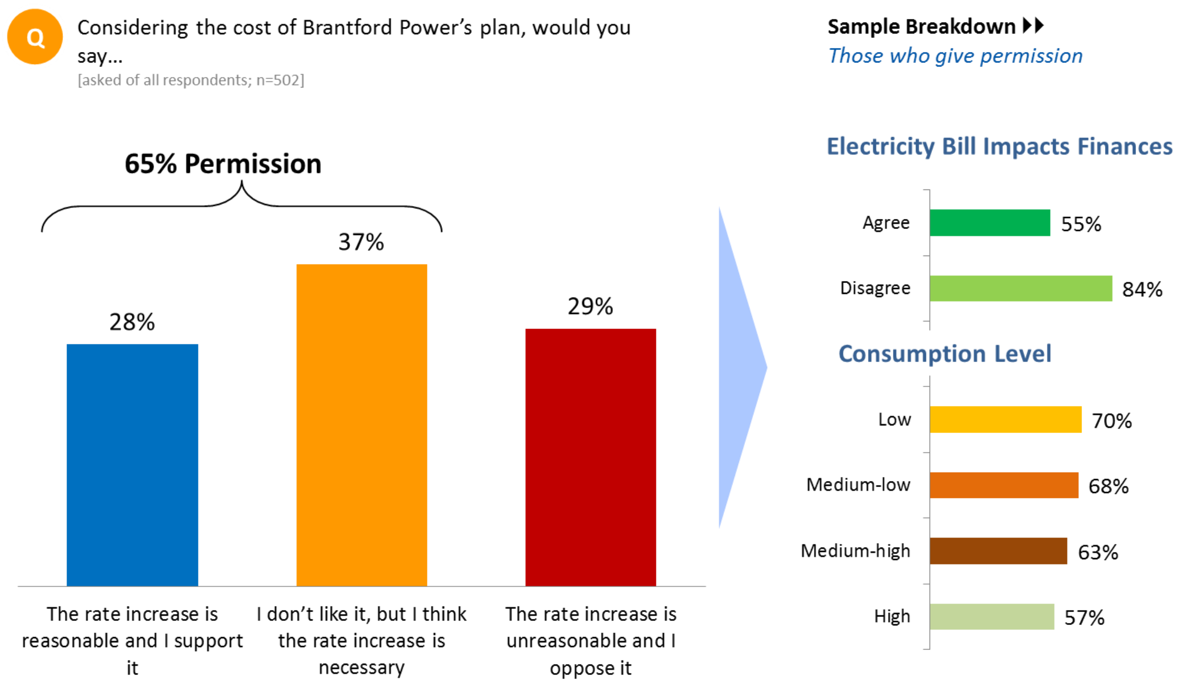
*So, in five years, by 2021, the average small business will be paying an **estimated $6.74 more per month** on the distribution portion of its electricity bill."*

Acceptance of Rate Increase

After having been read the preamble and considering the cost of Brantford Power's plan, 65% of residential customers give permission for the proposed rate increase. 28% say *the rate increase is reasonable and support it* outright, while 37% *don't like it, but think the rate increase is necessary.* Three-in-ten (29%) oppose the rate increase.

- Those who are not financially strained (84%) are much more likely to support the increase than those who are (55%).
- Likelihood to support the rate increase decreases with consumption from 70% of consumption customers to 57% of high consumption customers.

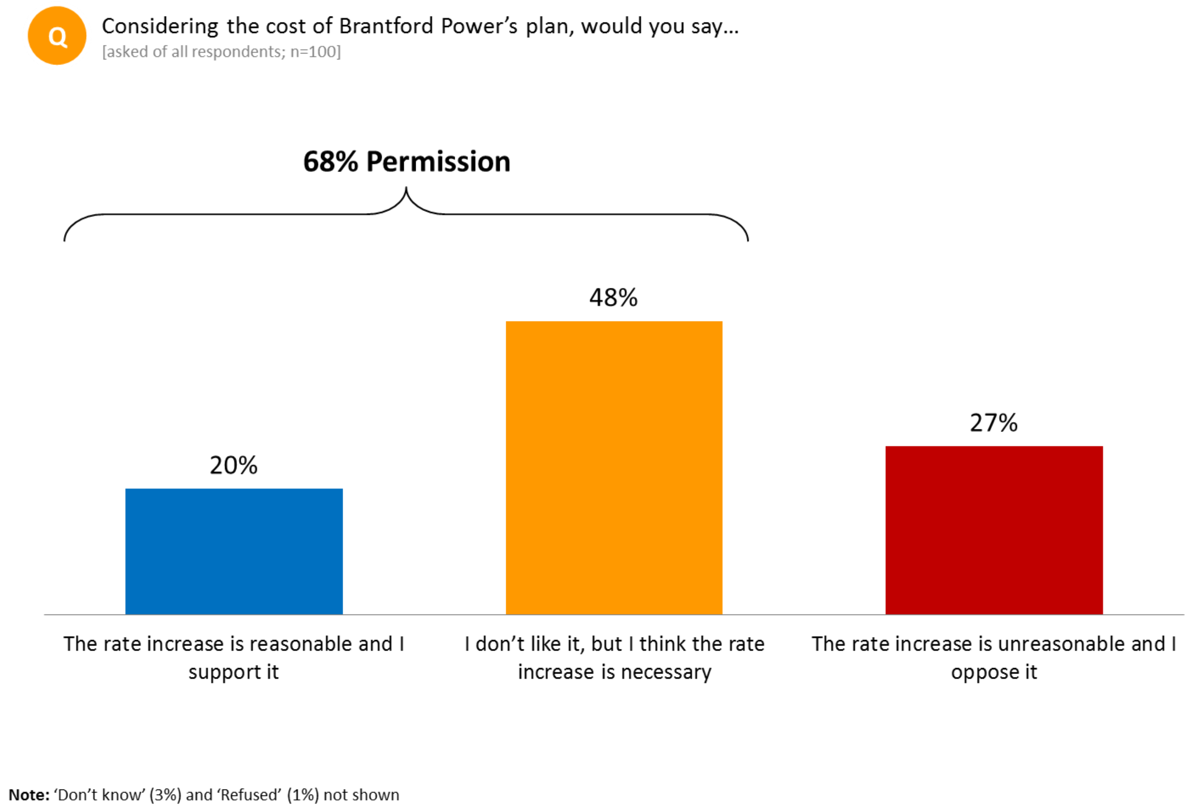
Figure RS.18 - Acceptance of Rate Increase



Note: 'Don't know'/'Refused' (6%) not shown

Overall, 68% of General Service customers accept the rate increase and give permission. Two-in-ten (20%) feel that *the rate increase is reasonable and support it*, while the plurality (48%) *don't like it, but think the rate increase is necessary*. 27% feel that the *rate increase is unreasonable and oppose it.*

Figure GS.18 - Acceptance of Rate Increase



Opinions on Proposed Rate Increase

The most common reason for those who support the increase outright is the importance of investing in infrastructure now, otherwise more will have to be spent later (39%). This is followed closely by those who find the increase marginal expense (37%).

37% of customers who don't like the idea of an increase feel that any no increase is good, but that Brantford Power's proposed increase is necessary. Investing now to avoid greater costs later (17%) is the second most common reason.

For those who oppose the rate increase, 38% feel that it is too costly and they are already paying a lot. 14% oppose it due to being on a fixed income, a pension, or simply cannot afford it.

Figure RS.19 – Opinion on Proposed Rate Increase

Q And why do you say that?

[asked of all respondents; n=502]

PERMISSION: Reasonable, support it	28% RS
Must invest in infrastructure for a better system - otherwise end up paying more later	39%
It is reasonable/$5 is fine	37%
Everything is going up in cost/inflation	9%
Other	7%
It is necessary - general	6%
Don't know	3%
Sample Size	**n=139**

NO PERMISSION: Unreasonable, oppose it	29% RS
Increase is too costly/already paying a lot	38%
Can't afford the increase/fixed income/pension	14%
Brantford Power or government should be responsible for costs, not consumers	13%
Costs are underestimated/don't trust the company	12%
Mismanagement - wasted money, company profiting too much	10%
Increase/upgrades are not necessary/service hasn't improved	8%
No choice	1%
Other	3%
Don't know	1%
Sample Size	**n=148**

PERMISSION: Don't like, but necessary	37% RS
Any increase is not good, but it is necessary	23%
Must invest in infrastructure for a better system - otherwise end up paying more later	17%
Increase is too costly/already paying a lot	13%
Everything is going up in cost/inflation	9%
Mismanagement - wasted money, company profiting too much	9%
Can't afford the increase/fixed income/pension	5%
It is necessary - general	3%
It is reasonable/$5 is fine	3%
No choice	3%
Brantford Power or government should be responsible for costs, not consumers	2%
Other	8%
Don't know	6%
Sample Size	**n=185**

20% of General Service customers support the increase outright. Half (51%) say that this is because the increase *is necessary, the system needs upgrading and power is a necessity*. One-quarter (25%) feel this way because *it is not a significant increase.*

Of the 48% of General Service customers who don't like the proposed increase but feel that it is necessary, 24% say that this is because the increase *is necessary, the system needs upgrading and power is a necessity*.

73% of those who oppose the increase do so because *the increase is too costly, and they are already paying enough.*

Figure RS.19 – Opinion on Proposed Rate Increase

Q And why do you say that?
[asked of all respondents; n=]

PERMISSION: Reasonable, support it	20% GS
It is necessary/system needs upgrading/need power	51%
It is not a significant increase	25%
Everything is going up	4%
No choice	4%
Other	10%
Don't Know	6%
Sample Size	**n=20**

NO PERMISSION: Unreasonable, oppose it	28% GS
Increase is too costly/already paying enough	73%
Funding should come from elsewhere/government responsibility	9%
Costs are just estimates - will end up paying more	3%
No choice	3%
Other	5%
Don't know	8%
Sample Size	**n=28**

PERMISSION: Don't like, but necessary	48% GS
It is necessary/system needs upgrading/need power	24%
Any increase is unwanted, but necessary	17%
Costs are just estimates - will end up paying more	11%
No choice	8%
Everything is going up	8%
Increase is too costly/already paying enough	7%
It is unnecessary	6%
Funding should come from elsewhere/government responsibility	5%
Don't know	12%
Refused	2%
Sample Size	**n=48**

Financial Flexibility and Level of Acceptance

It is expected that the proposed rate increase would have greater financial impact on some customers than others; consequently, the customers' level of acceptance for rate increase could differ depending on their level of financial flexibility. Financial flexibility was captured in the customer input statements:

The cost of my electricity bill has a major impact on my finances and requires that I do without some other important priorities.

Customers who agreed with these statements were considered to be "financially strained."

There is almost a 30-point difference between in the overall permission of financially strained households (55%) and not financially strained households (84%).

Figure RS.20 - Financial Flexibility and Level of Acceptance

	Financially Strained Households	Not Financially Strained Households
The rate increase is reasonable and I support it	19%	45%
I don't like it, but I think the rate increase is necessary	36%	39%
The rate increase is unreasonable and I oppose it	40%	14%
Overall Permission	**55%**	**84%**

Note: 'Don't know'/'Refused' not shown

One-quarter (25%) of General Service customers whose organizations are financially strained say *the rate increase is reasonable and they support it*, while 43% *don't like it, but think the rate increase is necessary.* Three-in-ten (31%) oppose think that *the rate is unreasonable and they oppose it*.

Almost all (88%) of not financially strained organizations *don't like the proposed rate increase, but think it is necessary*.

***Note**: Not financially strained organizations are an n-size of only 7.

Figure GS.20 - Financial Flexibility and Level of Acceptance

	Financially Strained Organization	Not Financially Strained Organization
The rate increase is reasonable and I support it	25%	0%
I don't like it, but I think the rate increase is necessary	43%	88%
The rate increase is unreasonable and I oppose it	31%	12%
Overall Permission	**68%**	**88%**

Note: 'Don't know'/'Refused' not shown

Survey Instruments

Residential Survey Instrument

A. Introduction

Hello, my name is ______________ and I'm calling from **Innovative Research Group** on behalf of **Brantford Power**, your electricity distributor.

Innovative Research Group is a national public opinion research firm. We have been commissioned by **Brantford Power** to help them better understand the needs and preferences of customers who are responsible for paying their household's electricity bill.

Brantford Power – which distributes electricity to homes and businesses in your community – is preparing to submit its 5-year investment plan to the Ontario Energy Board for regulatory review. Since this plan will impact your bill, Brantford Power wants to hear from you, so your views can help shape its plan.

A1. Would you mind if I had **10 minutes** of your time to ask you some questions? All your responses will be kept strictly confidential.

1	Yes	**[continue]**
2	No – NOT PRIMARY BILL PAYER	**[go to TRANSFER-1]**
3	No – BAD TIME	**ARRANGE CALLBACK**
4	No – HARD REFUSAL	**[Terminate]**

MONIT

This call may be monitored or audio taped for quality control and evaluation purposes.

1	PRESS TO CONTINUE

A2. Have I reached you at your home phone number?

1	Yes – SPEAKING, CONTINUE	[**continue to A3**]
2	No – AT OFFICE or WORKPLACE	[**continue to A3**]
3	No – on cellular or mobile phone	[skip to CELL]
99	Refused – LOG (THANK AND TERMINATE)	[Terminate]

CELL. Are you currently operating a car, truck or other motor vehicle?

1	YES	ARRANGE CALLBACK
2	NO	[continue to A3]
98	Refused – LOG (THANK AND TERMINATE)	[Terminate]

A3. Are you the person primarily responsible for paying the electricity bill in your household?

1	Yes – I pay the bill	[continue to A4]
2	Yes – shared responsibility	[continue to A4]
3	No	[go to TRANSFER-1]
98	Don't know (**DNR**)	**[Terminate]**

TRANSFER-1

Can I speak with the person in your household who usually pays the electricity bill?

1	Yes	[**BACK TO** ***INTRO***]
2	No – NOT AVAILABLE/BAD TIME	[ARRANGE CALLBACK]
3	No – HARD REFUSAL	[**Terminate**]
98	Don't know (**DNR**)	[**Terminate**]

A4. And can you confirm that your household receives an electricity bill from **Brantford Power**?

1	Yes	[**continue**]
2	No	[Terminate]
98	Don't know (**DNR**)	**[Terminate]**

GENDER Note gender by observation:

1 Male

2 Female

B. General Satisfaction

B5. PREAMBLE-1

To begin, I'd like to ask you some questions about your electricity service.

Today we want to talk about **Brantford Power** and the local electricity system in your community. This is the system that takes the electricity from provincial transmission towers and brings it to your home through a network of wires, poles and other equipment that is owned and operated by **Brantford Power.**

B6. How familiar are you with **Brantford Power**, which operates the electricity distribution system in your community? Would you say you are *very familiar*, *somewhat familiar*, *not familiar* or would you say you *don't know*?

1 Very familiar

2 Somewhat familiar

3 Not familiar

98 Don't know

99 Refused (DNR)

B7. Thinking specifically about the services provided to you and your community by **Brantford Power**, overall, how satisfied are you with the services that you receive from **Brantford Power**. Would you say you are very satisfied, somewhat satisfied, neither satisfied nor dissatisfied, somewhat dissatisfied, very dissatisfied or would you say you don't know?

1 Very satisfied

2 Somewhat satisfied

3 Neither satisfied or dissatisfied

4 Somewhat dissatisfied

5 Very dissatisfied

98 Don't know

99 Refused (**DNR**)

B8. Is there anything in particular **Brantford Power** can do to improve its service to you? [**OPEN**]

98 Don't know (**DNR**)

99 Refused (**DNR**)

C. Bill Knowledge & Impact

I'd now like to talk with you about your electricity bill …

C9. While **Brantford Power** is responsible for collecting payment for the entire electricity bill, they retain only about **17%** of the average residential customer's bill. The rest of the bill goes to power generation companies, transmission companies, the provincial government and regulatory agencies.

Before this survey, how familiar were you with the percentage of your electricity bill that went to **Brantford Power**? Would you say you were *very familiar, somewhat familiar, not familiar* or would you say you *don't know*?

1 Very familiar

2 Somewhat familiar

3 Not familiar

98 Don't know

99 Refused [**DNR**]

C10. Do you feel that the **17%** of your total electricity bill that you pay to **Brantford Power** for the services they provide is *very reasonable*, *somewhat reasonable*, *somewhat unreasonable*, *very unreasonable* or would you say you *don't know*?

1 Very reasonable

2 Somewhat reasonable

3 Somewhat unreasonable

4 Very unreasonable

98 Don't know

99 Refused [**DNR**]

D. System Reliability

READ PREAMBLE: Despite best efforts, no electrical distribution system can deliver *perfectly reliable* electricity. As a general rule, the more reliable the system, the more expensive the system is to build and maintain.

With that said, the average **Brantford Power** customer experiences **one** unexpected power outage per year.

D11. Have you experienced any power outages **in the past 12 months**, and if so, approximately how many? [**DO NOT READ LIST**]

0	No outages	[**SKIP to D14**]
1	1 outage	[CONTINUE]
2	2 outages	[CONTINUE]
3	3 outages	[CONTINUE]
4	4 outages	[CONTINUE]
5	5 outages	[CONTINUE]
6	6 outages	[CONTINUE]
7	7 outages	[CONTINUE]
8	8 or more outages	[CONTINUE]
98	Don't know (**DNR**)	[**SKIP to D14**]
99	Refused (**DNR**)	[**SKIP to D14**]

READ ONLY IF D11 = 1 thru 8

D12. And approximately how many minutes did the most recent power outage last? [DO NOT READ LIST; select category accordingly]

1	Less than 15 minutes
2	15 to less than 30 minutes [specify if less than *15 minutes*, if stated "less than 30 minutes"]
3	30 minutes to less than 1 hour
4	1 hour to less than 3 hours
5	3 hours to less than 6 hours
6	6 hours to less than 12 hours
7	12 to less than 24 hours
8	More than 24 hours
98	Don't know (**DNR**)
99	Refused (**DNR**)

READ ONLY IF D11 = 1 thru 8

D13. Thinking back to the **most recent** power outage you experienced as a **Brantford Power** customer, would you say the power outage …
[READ LIST; ROTATE 1 and 3]

1	Was a major inconvenience
2	Was a minor inconvenience
3	Was no inconvenience at all
97	Have never experienced an outage with Brantford Power (**DNR**)
98	Don't know (**DNR**)
99	Refused (**DNR**)

ASK ALL

I'd now like to read you a few statements about the electrical service that you receive from **Brantford Power**.

For each of the following statements, please tell me if you are *very satisfied*, *somewhat satisfied*, *neither satisfied nor dissatisfied*, *somewhat dissatisfied*, *very dissatisfied*, or would you say you *don't know*?

1	Very satisfied
2	Somewhat satisfied
3	Neither satisfied or dissatisfied
4	Somewhat dissatisfied
5	Very dissatisfied
98	Don't know
99	Refused [**DNR**]

D14. The reliability of your electricity service – as judged by the number of power outages you experience.

D15. The amount of time it takes to restore power when power outages occur.

D16. The quality of the power delivered to you as judged by the absence of voltage fluctuations that can result in the flickering or dimming of lights.

[END BATTERY]

D17. In your view, how do you think **Brantford Power** should address the **number** of customer power outages? Would you say … [**READ LIST**]

[Rotate response codes 1 and 3]

1	Spend what is needed to **reduce** the number of unexpected power outages
2	Spend what is needed to **maintain** the current level of unexpected power outages
3	Accept **more** power outages in order to help keep customer costs from rising
98	Don't Know (**DNR**)
99	Refused (**DNR**)

D18. Overall, the average **Brantford Power** customer is without power for about **one hour per year**.

In your view, how do you think **Brantford Power** should address the **length of time** customers are without power? Would you say … [**READ LIST**]

[Rotate response codes 1 and 3]

1 Spend what is needed to **reduce** the length of unexpected power outages

2 Spend what is needed to **maintain** the current length of unexpected outages

3 Accept **longer** time without power in order to help minimize customer costs from rising

98 Don't Know (**DNR**)

99 Refused (**DNR**)

E. System Challenges & Priorities

E19. [**PREAMBLE to E20**] While **Brantford Power** believes it has done its best to prolong the life of the assets that make up the distribution system, many of these assets are approaching the end of their useful life.

As part of its investment plan, **Brantford Power** is proposing a significant infrastructure replacement or renewal program. The estimated cost of this system renewal program is **$3.4 million** between 2017 and 2021.

Although this plan will allow **Brantford Power** to make the necessary investments to maintain system reliability, **it will have an impact on customer bills**.

E20. Which of the following statements best represents your point of view?
[Read and Rotate statements 1 and 2]
Some customers have said …

1 Brantford Power should invest what it takes to replace the system's aging infrastructure to maintain system reliability; even if that increases my monthly electricity bill by a few dollars over the next few years.

Others have said …

2 Brantford Power should lower its estimated investment in renewing the system's aging infrastructure to lessen the impact of any bill increase; even if that means more or longer power outages.

98 Don't know (**DNR**)

99 Refused (**DNR**)

System Service Questions

[PREAMBLE FOR E21] Modernizing the grid can allow **Brantford Power** to improve reliability. Investments such as automated switches may allow **Brantford Power** to quickly identify the location of outages in order to minimize the number of people impacted by outages and to restore electricity to customers more quickly than was previously possible.

E21. Given there are many other areas of needed investments, such as connecting new customers, replacing aging equipment and expanding capacity for long-term growth, how important do you feel it is for **Brantford Power** to invest now in modernizing the grid?

1 Very important
2 Somewhat important
3 Not very important
4 Not important at all
98 Don't know (**DNR**)
99 Refused (**DNR**)

CDM Questions

E22. One of the most cost effective ways for **Brantford Power** to reduce its required investments in the distribution system is through customer uptake of conservation programs.

When customers consume less electricity at peak demand times, less strain is put on the distribution system and as a result, customers save money in two ways: 1) a lower level of investment is required by **Brantford Power** to expand and maintain the distribution system's capacity to deliver electricity; and 2) customers pay less when they reduce their electricity consumption.

Have you ever participated in a **Brantford Power** conservation program?

1 Yes

2 No

98 Don't know (**DNR**)

99 Refused (**DNR**)

E23. How likely are **you** to participate in <u>future</u> **Brantford Power** conservation programs that could help reduce your electricity consumption? Would you say … [**READ LIST**]

1 Very likely
2 Somewhat likely
3 Not very likely
4 Not at all likely
98 Don't know (**DNR**)
99 Refused (**DNR**)

E23b. How *good* or *poor* a job does **Brantford Power** do at providing you with information on available tools and programs that can help you manage your household electricity consumption? Would you say … [**READ LIST**]

1	A very good job
2	A good job
3	A poor job
4	A very poor job
98	Don't know (**DNR**)
99	Refused (**DNR**)

Relocation Question

[PREAMBLE FOR E24] At some point over the next 5 years, Brantford Power will have to relocate from the 3 separate buildings currently rented from the City of Brantford. Brantford Power will consider its options for a consolidated location to accommodate all of its staff and equipment. **Brantford Power** has currently allocated **$15.4 million** for this facility relocation.

E24. In regard to Brantford Power's facility relocation, which option do you think they should pursue?

1	Build a new facility that will meet their current and foreseeable future needs
2	By an existing facility and refurbish it to meet their current and foreseeable future needs
3	Find new rental space to house equipment and staff
4	Something else
98	Don't know (**DNR**)
99	Refused (**DNR**)

F. Reaction to Customer Input

The following statements have been made by customers throughout **Brantford Power's** community consultation process.

For each statement, please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree.

1	Strongly agree
2	Somewhat agree
3	Neither agree nor disagree (**DNR**)
4	Somewhat disagree
5	Strongly disagree
98	Don't Know (**DNR**)
99	Refused (**DNR**)

RANDOMIZE QUESTIONS

Willingness to Pay

F25. I'm willing to pay a bit more for my electricity because investing in upgrading the system is money well spent.

Impact of Rate Increase on Others

F26. I can personally afford to pay more for electricity, but I am worried about the impact a rate increase will have on others.

Pay Now or Later

F27. Brantford Power should invest in our electricity system infrastructure **now** or customers will end up paying more the longer we delay our system renewal.

Deferring to the Experts

F28. The electricity sector is so complicated and confusing; we just have to trust that the experts at Brantford Power will find the right balance in keeping cost down while making the right investments and spending decisions.

Modernizing the Grid

F29. **Brantford Power** should invest in new infrastructure and technology to minimize the number and length of power service interruptions.

Growing Community

F30. Brantford is a growing community, so it is natural to expect that we are going to pay more for things like investments in our electricity distribution system.

G. Assessment of Plan

G31. PREAMBLE

Brantford Power believes that proactive renewal and consistent maintenance is needed to maintain system performance, while keeping the impact on customer bills manageable over the long-term. Between 2017 and 2021, **Brantford Power's** proposed plan will see it …

- spend an estimated **$54.6 million** on on-going maintenance and the operation of the distribution system; and
- invest an estimated **$22.8 million** in new equipment and infrastructure priorities that will help ensure system reliability.

To fund this plan, **Brantford Power** is proposing the **average residential customers' rate increase by approximately $1.14 per month** on the distribution portion of their bill over the next five years.

So, in five years, by 2021, the average residential household will be paying an **estimated $5.68 more per month** on the distribution portion of its electricity bill.

G32. Considering the cost of Brantford Power's plan, would you say [**READ LIST**] …
Rotate response codes "1 "and "3"

1 The rate increase is reasonable and I support it
2 I don't like it, but I think the rate increase is necessary
3 The rate increase is unreasonable and I oppose it
98 Don't know (**DNR**)
99 Refused (**DNR**)

Ask only if G32 = 1, 2 or 3

G33. And why do you say that? [**OPEN**]

98 Don't know (**DNR**)

99 Refused (**DNR**)

H. Segmentation & Demographics

Lastly, I'd like to ask you some general questions about the electricity system in Ontario.

For each statement please tell me if you would strongly agree, somewhat agree, somewhat disagree or strongly disagree. If you don't know enough to say or don't have an opinion just let me know.

1	Strongly agree
2	Somewhat agree
3	Somewhat disagree
4	Strongly disagree
98	Don't know/No opinion
99	Refused [**DNR**]

[ROTATE H34 & H35]

H34. The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.

H35. Customers are well served by the electricity system in Ontario.

[END BATTERY]

These last few questions are for statistical purposes only and we remind you again that all of your responses are completely confidential.

H36. In which year were you born? [**Enter YEAR**]

INTERVIEWER NOTE: if REFUSE; ask "AGE".

AGE: Can you tell me what age category do you fall into? [**READ LIST**]

0	Less than 18
1	18-25
2	25-34
3	35-44
4	45-54
5	55-64
6	65 years or older
99	Refused (**DNR**)

H37. Do you own or rent your home?

1	Own
2	Rent
99	Refused (**DNR**)

H38. How would you describe your primary residence? Would you say you live in …
[**READ LIST**]

1	A fully-detached home
2	A semi-detached home
3	An apartment or condo building
99	Refused (**DNR**)

H39. Counting yourself, how many people live in your household? [**DO NOT READ LIST**]

1	1 person
2-7	Enter number of people
8	8 or more
99	Refused (**DNR**)

THANK and END SURVEY

These are all the questions we have for you today/tonight. Thank you very much for taking the time to complete this survey.

General Service Survey Instrument

A. Introduction

INTRO

Hello, my name is _______________ and I'm calling from **Innovative Research Group** on behalf of **Brantford Power**, your local electricity distributor.

Innovative Research Group is a national public opinion research firm. We have been commissioned by **Brantford Power** to help them better understand the needs and preferences of its customers.

Can I please speak to the person who is in-charge of managing the electricity bill at your organization?

1) Yes, speaking <**contact on the line**> **[skip to A1]**

2) Yes <**transferred to contact**> **[skip to A1]**

3) No <**not the right contact person**> **[GO to "NEW"]**

4) No <**busy**> "When is a good time to callback?" **[record callback time]**

5) Maybe <**may I ask who is calling?**> **[skip to GATE]**

NEW. And … can I have their …

First Name ____________

Last Name ____________

Title/Position __________

Phone Number _________

ASK to be transferred …

- **if transferred → go to A1**
- **if not transferred → Thank & Add to Callback List**

GATE. My name is _________ and I'm calling on behalf of your local electricity distributor, **Brantford Power**.

INTERVIEWER NOTE: If gatekeeper asks the purpose of call → I'd like to ask the person in-charge of managing the electricity bill at your organization a few questions concerning a **Brantford Power** customer consultation.

1) Yes <**transferred to contact**>		**[skip to A1]**
2) No <**not available**>	"When is a good time to callback?	**[record callback time and GO to "NEW"]**
3) No <**not interested in talking**>		**[Thank & Terminate]**

A1 QUAL PREAMBLE:

Read preamable again, if transferred to new person:

Hello, my name is _________ and I'm calling from **Innovative Research Group**, a national public opinion research firm. We have been hired by **Brantford Power** to help them better understand the needs and preferences of their customers.

IF INTRO = 1, read:

Brantford Power – which distributes electricity to residential and business customers in your community – is preparing to submit its investment and spending plan to the **Ontario Energy Board** for regulatory review. Since this plan will impact your bill, **Brantford Power** wants to hear from you, so your views can help shape its plan.

A1. Would you mind if I had **10 minutes** of your time to ask you some questions? All your responses will be kept strictly confidential.

Yes	1	[continue]
No – NOT PRIMARY BILL PAYER	2	[go to TRANSFER-1]
No – BAD TIME	3	ARRANGE CALLBACK
No – HARD REFUSAL	4	[Terminate]

MONIT: This call may be monitored or audio taped for quality control and evaluation purposes.

PRESS TO CONTINUE 1

A2. Just to confirm, does your organization receive an electricity bill from **Brantford Power**?

01	**YES**	1	**[continue]**
02	**NO**	2	**[Terminate]**
98	**DK (DO NOT READ)**	98	**[Terminate]**

A3. As part of your job, are you in-charge of managing or overseeing your organization's electricity bill?

Yes	1	[**Continue to A4**]
No	2	CAN I SPEAK TO THE PERSON WHO MANAGES YOUR ORGANIZATION'S **ELECTRICITY** BILL?**[Return to NEW]**
DK	3	CAN I SPEAK TO THE PERSON WHO MANAGES YOUR ORGANIZATION'S **ELECTRICITY** BILL? **[Return to NEW]**

A4. **READ STATEMENT TO RESPONDENT**:
While you may be a **Brantford Power** residential customer, for the following questions I'd like you to answer from the perspective of the business or organization that you represent. While we are currently surveying residential customers, you have been randomly selected from a limited sample of small business and non-residential customers and it's important we understand the unique needs and preferences of this group of customers.

So again, please answer the following questions from the perspective of your business or organization's needs and preferences.

B. General Satisfaction

B5. PREAMBLE-1

To begin, I'd like to ask you some questions about your electricity service.

Today we want to talk about **Brantford Power** and the local electricity system in your community. This is the system that takes the electricity from provincial transmission towers and brings it to your home through a network of wires, poles and other equipment that is owned and operated by **Brantford Power.**

B6. How familiar are you with **Brantford Power**, which operates the electricity distribution system in your community? Would you say you are *very familiar*, *somewhat familiar*, *not familiar* or would you say you *don't know*?

1 Very familiar
2 Somewhat familiar
3 Not familiar
98 Don't know
99 Refused (DNR)

B7. Thinking specifically about the services provided to **<u>your business</u>** by **Brantford Power**, overall, how satisfied are you with the services that you receive from **Brantford Power**. Would you say you are very satisfied, somewhat satisfied, neither satisfied nor dissatisfied, somewhat dissatisfied, very dissatisfied or would you say you don't know?

1 Very satisfied
2 Somewhat satisfied
3 Neither satisfied or dissatisfied
4 Somewhat dissatisfied
5 Very dissatisfied
98 Don't know
99 Refused (**DNR**)

B8. Is there anything in particular **Brantford Power** can do to improve its service to **<u>your business</u>**? [**OPEN**]

98 Don't know (**DNR**)
99 Refused (**DNR**)

C. Bill Knowledge & Impact

I'd now like to talk with you about **<u>your business'</u>** electricity bill …

C9. While **Brantford Power** is responsible for collecting payment for the entire electricity bill, they retain only about **13%** of the average **<u>general service or small business</u>** customer's bill. The rest of the bill goes to power generation companies, transmission companies, the provincial government and regulatory agencies.

Before this survey, how familiar were you with the percentage of **your business'** electricity bill that went to **Brantford Power**? Would you say you were *very familiar, somewhat familiar, not familiar* or would you say you *don't know*?

1 Very familiar
2 Somewhat familiar
3 Not familiar
98 Don't know
99 Refused [**DNR**]

C10. Do you feel that the **13%** of your total electricity bill that you pay to **Brantford Power** for the services they provide is *very reasonable*, *somewhat reasonable*, *somewhat unreasonable*, *very unreasonable* or would you say you *don't know*?

1 Very reasonable
2 Somewhat reasonable
3 Somewhat unreasonable
4 Very unreasonable
98 Don't know
99 Refused [**DNR**]

D. System Reliability

READ PREAMABLE: Despite best efforts, no electrical distribution system can deliver *perfectly reliable* electricity. As a general rule, the more reliable the system, the more expensive the system is to build and maintain.

With that said, the average **Brantford Power** customer experiences **one** unexpected power outage per year.

D11. Has **your business** experienced any power outages **in the past 12 months**, and if so, approximately how many? [**DO NOT READ LIST**]

0 No outages [**SKIP to D14**]
1 1 outage [CONTINUE]
2 2 outages [CONTINUE]
3 3 outages [CONTINUE]
4 4 outages [CONTINUE]
5 5 outages [CONTINUE]
6 6 outages [CONTINUE]
7 7 outages [CONTINUE]
8 8 or more outages [CONTINUE]
98 Don't know (**DNR**)[**SKIP to D14**]
99 Refused (**DNR**) [**SKIP to D14**]

READ ONLY IF D11 = 1 thru 8

D12. And approximately how many minutes did the most recent power outage last at **your business**? [DO NOT READ LIST; select category accordingly]

1 Less than 15 minutes
2 15 to less than 30 minutes [specify if less than *15 minutes*, if stated "less than 30 minutes"]
3 30 minutes to less than 1 hour
4 1 hour to less than 3 hours
5 3 hours to less than 6 hours
6 6 hours to less than 12 hours
7 12 to less than 24 hours
8 More than 24 hours
98 Don't know (**DNR**)
99 Refused (**DNR**)

READ ONLY IF D11 = 1 thru 8

D13. Thinking back to the **most recent** power outage you experienced at **your business** as a **Brantford Power** customer, would you say the power outage …
[READ LIST; ROTATE 1 and 3]

Had a significant cost to my business	1
Had a minor cost to my business	2
Had barely any cost to my business, just a bit of inconvenience	3
Have never experienced an outage with Brantford Power (**DNR**)	97
Don't know (**DNR**)	98
Refused (**DNR**)	99

ASK ALL

I'd now like to read you a few statements about the electrical service that **your business** receives from **Brantford Power**.

For each of the following statements, please tell me if you are *very satisfied*, *somewhat satisfied*, *neither satisfied nor dissatisfied*, *somewhat dissatisfied*, *very dissatisfied*, or would you say you *don't know*?

1	Very satisfied
2	Somewhat satisfied
3	Neither satisfied or dissatisfied
4	Somewhat dissatisfied
5	Very dissatisfied
98	Don't know
99	Refused [**DNR**]

D14. The reliability of your electricity service – as judged by the number of power outages you experience.

D15. The amount of time it takes to restore power when power outages occur.

D16. The quality of the power delivered to you as judged by the absence of voltage fluctuations that can result in the flickering lights or may affect your equipment.

[END BATTERY]

D17. In your view, how do you think **Brantford Power** should address the **<u>number</u>** of customer power outages? Would you say … [**READ LIST**]

[Rotate response codes 1 and 3]

1	Spend what is needed to **<u>reduce</u>** the number of unexpected power outages
2	Spend what is needed to **<u>maintain</u>** the current level of unexpected power outages
3	Accept **<u>more</u>** power outages in order to help keep customer costs from rising
98	Don't Know (**DNR**)
99	Refused (**DNR**)

D18. Overall, the average **Brantford Power** customer is without power for about **<u>one hour</u> per year**.

In your view, how do you think **Brantford Power** should address the **<u>length of time</u>** customers are without power? Would you say … [**READ LIST**]

[Rotate response codes 1 and 3]

1	Spend what is needed to **<u>reduce</u>** the length of unexpected power outages
2	Spend what is needed to **<u>maintain</u>** the current length of unexpected outages
3	Accept **<u>longer</u>** time without power in order to help minimize customer costs from rising
98	Don't Know (**DNR**)
99	Refused (**DNR**)

E. System Challenges & Priorities

System Renewal Question

E19. [**PREAMBLE to E20**] While **Brantford Power** believes it has done its best to prolong the life of the assets that make up the distribution system, many of these assets are approaching the end of their useful life.

As part of its investment plan, **Brantford Power** is proposing a significant infrastructure replacement or renewal program. The estimated cost of this system renewal program is **$3.4 million** between 2017 and 2021.

Although this plan will allow **Brantford Power** to make the necessary investments to maintain system reliability, **it will have an impact on customer bills**.

E20. Which of the following statements best represents your point of view?
[Read and Rotate statements 1 and 2]
Some customers have said ...

1 Brantford Power should invest what it takes to replace the system's aging infrastructure to maintain system reliability; even if that increases **my business'** monthly electricity bill by a few dollars over the next few years.

Others have said ...

2 Brantford Power should lower its estimated investment in renewing the system's aging infrastructure to lessen the impact of any bill increase; even if that means more or longer power outages.

98 Don't know (**DNR**)
99 Refused (**DNR**)

System Service Questions

[PREAMBLE FOR E21] Modernizing the grid can allow **Brantford Power** to improve reliability. Investments such as automated switches may allow **Brantford Power** to quickly identify the location of outages in order to minimize the number of people impacted by outages and to restore electricity to customers more quickly than was previously possible.

E21. Given there are many other areas of needed investments, such as connecting new customers, replacing aging equipment and expanding capacity for long-term growth, how important do you feel it is for **Brantford Power** to invest now in modernizing the grid?

1 Very important
2 Somewhat important
3 Not very important
4 Not important at all
98 Don't know (**DNR**)
99 Refused (**DNR**)

CDM Questions

E22. One of the most cost effective ways for **Brantford Power** to reduce its required investments in the distribution system is through customer uptake of conservation programs.

When customers consume less electricity at peak demand times, less strain is put on the distribution system and as a result, customers save money in two ways: 1) a lower level of investment is required by **Brantford Power** to expand and maintain the distribution system's capacity to deliver electricity; and 2) customers pay less when they reduce their electricity consumption.

Has **your business** ever participated in a **Brantford Power** conservation program?

1 Yes
2 No
98 Don't know (**DNR**)
99 Refused (**DNR**)

E23. How likely is **your business** to participate in <u>future</u> **Brantford Power** conservation programs that could help reduce your electricity consumption? Would you say … [**READ LIST**]

1 Very likely
2 Somewhat likely
3 Not very likely
4 Not at all likely
98 Don't know (**DNR**)
99 Refused (**DNR**)

E23b. How *good* or *poor* a job does **Brantford Power** do at providing **your business** with information on available tools and programs that can help you manage your **organization's** electricity consumption? Would you say … [**READ LIST**]

1 A very good job
2 A good job
3 A poor job
4 A very poor job
98 Don't know (**DNR**)
99 Refused (**DNR**)

Relocation Question

[PREAMBLE FOR E24] At some point over the next 5 years, Brantford Power will have to relocate from the 3 separate buildings currently rented from the City of Brantford. Brantford Power will consider its options for a consolidated location to accommodate all of its staff and equipment. **Brantford Power** has currently allocated **$15.4 million** for this facility relocation.

E24. In regard to Brantford Power's facility relocation, which option do you think they should pursue?

1 Build a new facility that will meet their current and foreseeable future needs
2 By an existing facility and refurbish it to meet their current and foreseeable future needs
3 Find new rental space to house equipment and staff
4 Something else
98 Don't know (**DNR**)
99 Refused (**DNR**)

F. Reaction to Customer Input

The following statements have been made by customers throughout **Brantford Power's** community consultation process.

For each statement, please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree.

1	Strongly agree
2	Somewhat agree
3	Neither agree nor disagree (**DNR**)
4	Somewhat disagree
5	Strongly disagree
98	Don't Know (**DNR**)
99	Refused (**DNR**)

RANDOMIZE QUESTIONS

Willingness to Pay

F25. My organization would be willing to pay a bit more for my electricity if it means better system reliability.

Impact of Rate Increase on Others

F26. My organization can afford to pay more for electricity, but I am worried about the impact a rate increase will have on my local customers and suppliers.

Pay Now or Later

F27. **Brantford Power** should invest in our electricity system infrastructure **now** or customers will end up paying more the longer we delay our system renewal.

Deferring to the Experts

F28. The electricity sector is so complicated and confusing; we just have to trust that the experts at **Brantford Power** will find the right balance in keeping cost down while making the right investments and spending decisions.

Modernizing the Grid

F29. **Brantford Power** should invest in new infrastructure and technology to minimize the number and length of power service interruptions.

Growing Community

F30. Brantford is a growing community, so it is natural to expect that we are going to pay more for things like investments in our electricity distribution system.

G. Assessment of Plan

G31. PREAMBLE

Brantford Power believes that proactive renewal and consistent maintenance is needed to maintain system performance, while keeping the impact on customer bills manageable over the long-term. Between 2017 and 2021, **Brantford Power's** proposed plan will see it …

- spend an estimated **$54.6 million** on on-going maintenance and the operation of the distribution system; and
- invest an estimated **$22.8 million** in new equipment and infrastructure priorities that will help ensure system reliability.

To fund this plan, **Brantford Power** is proposing the **average *general service* or *small business* customers' rate increase by approximately $1.35 per month** on the distribution portion of their bill over the next five years.

So, in five years, by 2021, the average small business will be paying an **estimated $6.74 more per month** on the distribution portion of its electricity bill.

G32. Considering the cost of Brantford Power's plan, would you say [**READ LIST**] …
Rotate response codes "1 "and "3"

1	The rate increase is reasonable and I support it
2	I don't like it, but I think the rate increase is necessary
3	The rate increase is unreasonable and I oppose it
98	Don't know (**DNR**)
99	Refused (**DNR**)

Ask only if G32 = 1, 2, 3

G33. And why do you say that? [**OPEN**]

98	Don't know (**DNR**)
99	Refused (**DNR**)

H. Segmentation & Firmographics

Lastly, I'd like to ask you some general questions about the electricity system in Ontario.

For each statement please tell me if you would strongly agree, somewhat agree, somewhat disagree or strongly disagree. If you don't know enough to say or don't have an opinion just let me know.

1	Strongly agree
2	Somewhat agree
3	Somewhat disagree
4	Strongly disagree
98	Don't know/No opinion
99	Refused [**DNR**]

[ROTATE H34 & H35]

H34. The cost of my electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.

H35. Customers are well served by the electricity system in Ontario.

[END BATTERY]

These last few questions are for statistical purposes only and we remind you again that all of your responses are completely confidential.

H36. Which of the following best describes the sector in which your organization operates?

Restaurant	1
Retail	2
Commercial	3
Multi-residential	4
Hospitality (i.e. catering, hotel operations)	5
Manufacturing	6
Other [Please specify: _______________]	88
Don't know / Refused (**DNR**)	98

H37. Which of the following best describes the **hours of operation** of your organization? Would you say … [**READ LIST**]

We are open 24/7	1
We operate several shifts each day, but are not open 24/7	2
We operate during regular business hours only	3
We operate outside of regular business hours, but do not have shifts	4
Other (please specify): _______________________	88
Don't know / Refused (**DNR**)	98

H38. And, which of the following best describes **when your organization operates** through the week? Would you say … [**READ LIST**]

We operate on weekdays only	1
We operate on weekdays and weekends	2
Other (please specify): ______________________	88
Don't know / Refused (**DNR**)	98

H39. How many **full-time** employees work at your organization? [**record #]**

H40. Any how many **part-time** employees work at your organization? [**record #]**

THANK and END SURVEY

Thank you very much for taking the time to complete this survey.

Appendix

Customer Consultation Workbook

2017 Rate Application Review

Residential

Customer Consultation Workbook

BRANTFORD power
Your delivery company

February 2016

Brantford Power Inc. (BPI) is the local distribution company responsible for electricity distribution in the City of Brantford.

With approximately 60 employees, BPI operates and maintains a distribution system serving a population of approximately 94,000 with 39,300 residential and business customers over a 74 square kilometer area.

BPI has been operating since 1935 and is wholly owned by the City of Brantford through its holding company, the Brantford Energy Corporation.

BPI's Service Territory and Transformer Stations

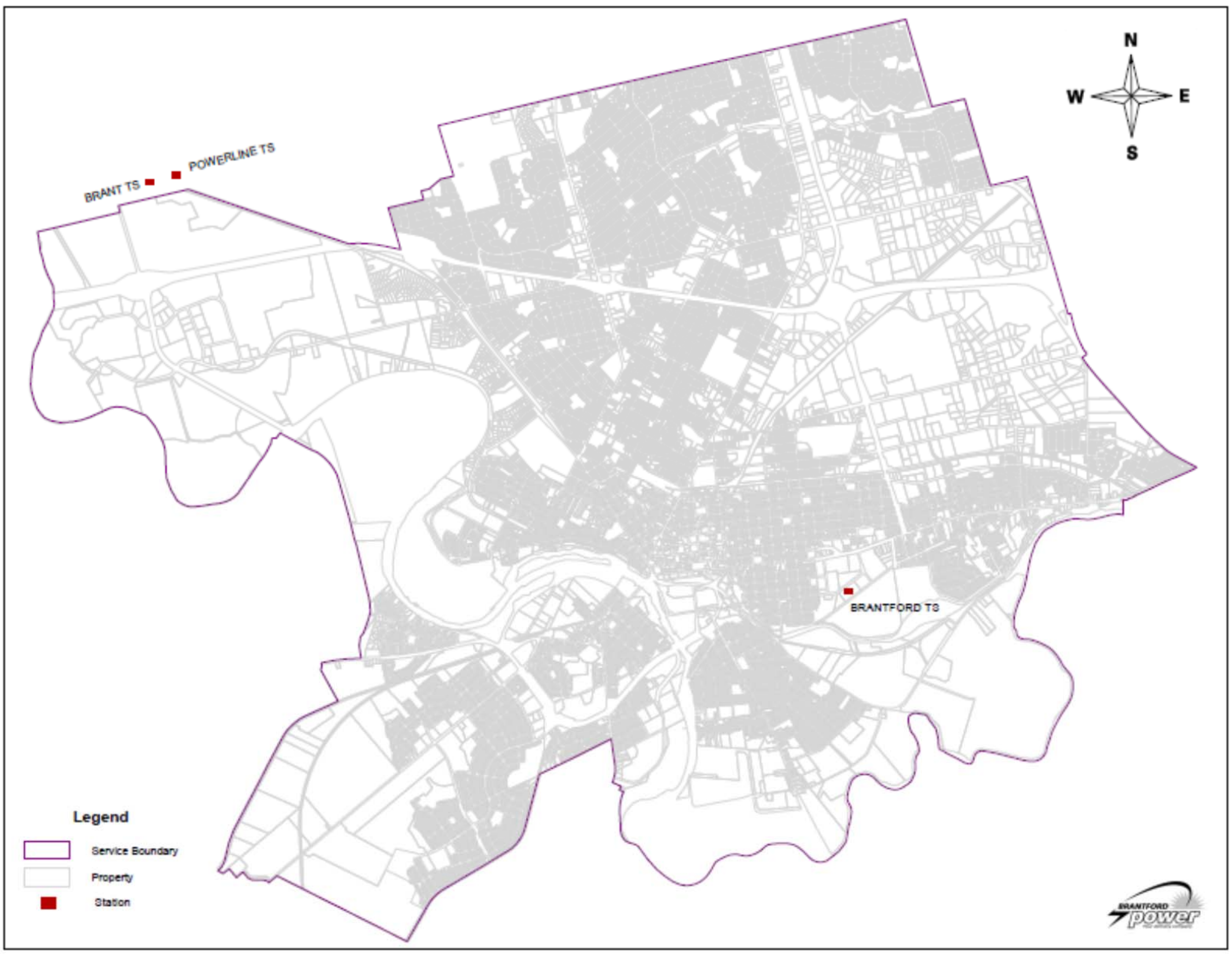


Table of Contents

What’s this consultation about?

The purpose of this customer consultation is to collect your feedback on BPI’s investment and spending plan for 2017 to 2021.

Brantford Power’s goal is to deliver safe and reliable electricity to homes and local businesses as efficiently as possible and at an affordable price. However, there is a balancing act that all utilities must consider when planning for the future: system reliability vs. the cost to consumers. No distribution system delivers perfectly reliable electricity. Generally, the more reliable the system, the more expensive the system is to build and maintain.

This customer consultation is designed to collect your feedback on the reliability of the electricity distribution system and the spending decisions BPI will need to make over the next five years. Ultimately, this consultation will help BPI ensure alignment between its operational and capital investment plans and customers needs and preferences.

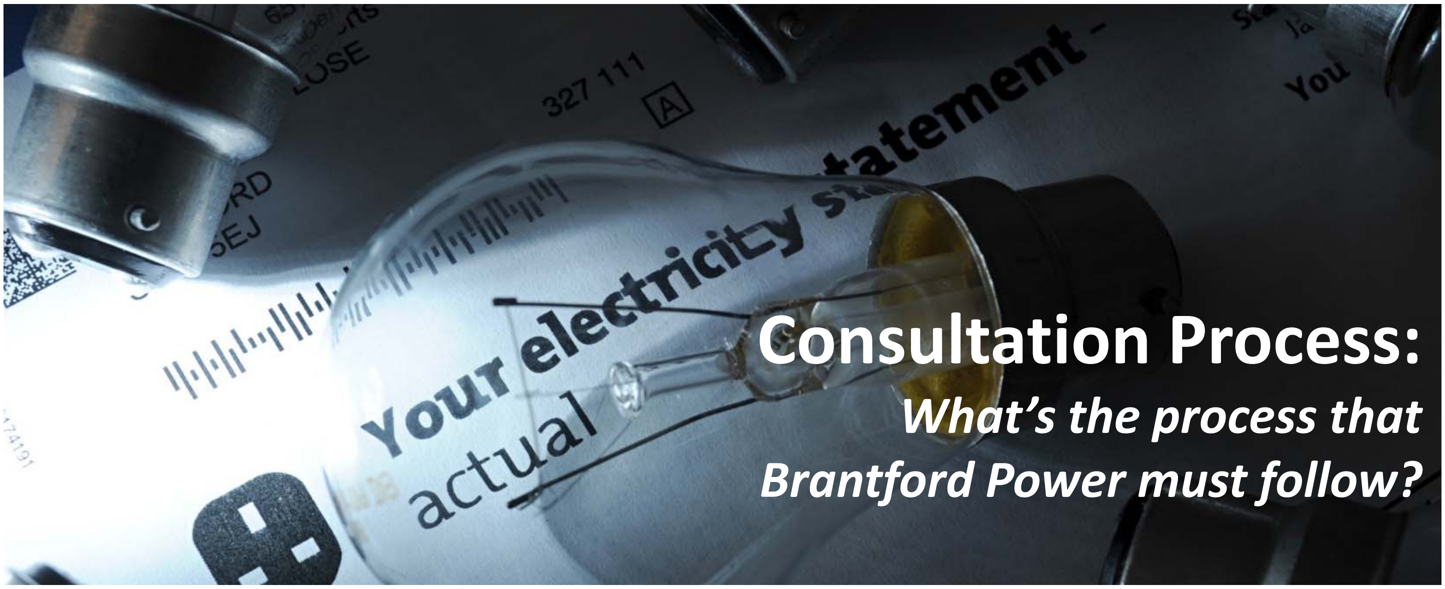
As a BPI customer, this is an opportunity for you to tell your local distribution company what you think about their plan and the cost implications this plan will have on you. This is also an opportunity for BPI to explain to its customers the challenges in operating and maintaining the local electricity distribution system, and more importantly how BPI intends to meet those challenges.

To participate in this review, you do not need to be an expert on electrical distribution systems. This workbook explains key parts of the electrical distribution system, the challenges facing the system, BPI’s recent work to maintain the system, and the company’s budgetary plan for 2017 to 2021.

BPI does not expect you to make electrical engineering decisions. BPI wants to hear about the electricity issues that matter most to you and whether or not you feel the utility’s spending and investing priorities seem reasonable.

This workbook is designed to give you enough background about these issues for you to develop an informed opinion.

BRANTFORD power Your delivery company



Consultation Process:
What's the process that Brantford Power must follow?

How are electricity rates determined in Ontario?

The electricity industry in Ontario is regulated by the Ontario Energy Board (OEB), which recently developed a new regulatory framework that requires electricity distributors, such as BPI, to identify customer needs and preferences related to its distribution system plan.

BPI is funded by the distribution rates paid by its customers. Periodically, BPI is required to file an application with the OEB to determine the funding available to operate and maintain the distribution system. BPI must submit evidence to justify the amount of funding it needs to safely and reliably distribute electricity to its customers.

As a customer, how are my interests protected?

BPI's rationale for a customer rate adjustment is assessed in an open and transparent public process known as a rate hearing. Any individual or group may intervene on BPI's application to ask questions or challenge BPI's plans and assumptions. At the end of the process, the OEB weighs the evidence and decides on the rates BPI can charge for distribution.

Why is my feedback important?

Your feedback will inform BPI's rate design for 2017 which in turn will form the new base rates on which annual inflation adjustments will be applied in 2018 to 2021. Customer feedback will be presented to the OEB and public intervenors (who represent various ratepayer groups) when BPI files its rate application for 2017. As part of the rate hearing process, the OEB will be reviewing how BPI acquired and responded to customer feedback in its planning process.

Rate Application Process

1. BPI assesses system needs
2. **Collect customer feedback on Distribution System Plan**
3. Refine plan (where necessary)
4. Report on how plan responds to customer input
5. File plan with Ontario Energy Board
6. Interrogatories, technical conference, and rate hearing
7. Ontario Energy Board sets BPI's distribution rates

Innovative Research Group Inc. has been engaged by BPI to collect participant feedback as an impartial third-party. Innovative Research Group will deliver the collected customer feedback to BPI to assist them in shaping their rate application and distribution system plan.

INNOVATIVE RESEARCH GROUP

Consumer feedback on Ontario's electricity system

There are a number of ways for consumers to voice their opinions on provincial, regional and local electricity issues. However, this consultation is about your local distribution system and your preferences on how BPI should use your money.

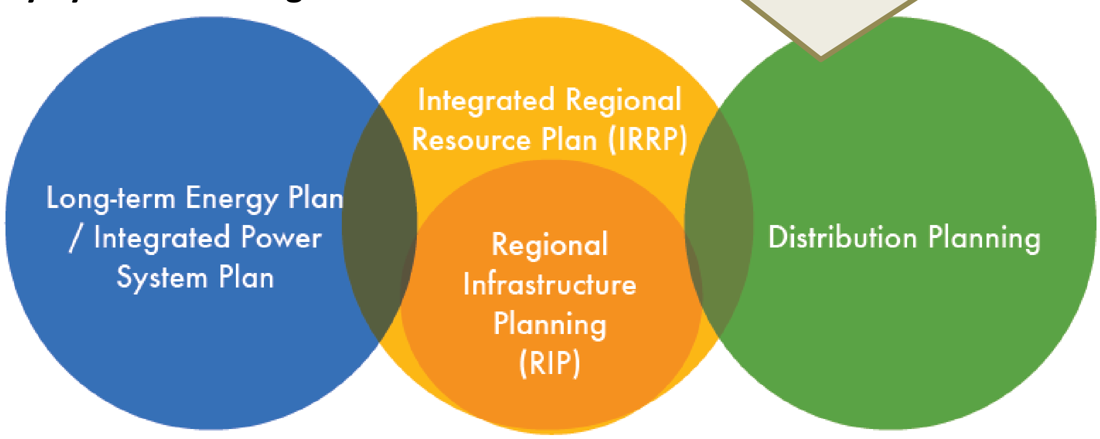
If you're interested in broader medium- and long-term electricity issues such as Ontario's Long-Term Energy Plan, regional planning, conservation planning and general energy policy in the province, there are other opportunities to provide your feedback.

Ontario's Long Term Energy Plan: The Ontario Government's plan details how electricity will be generated and the longer-term conservation strategy for the province.

Regional Planning: The Independent Electricity System Operator (IESO) looks ahead to the future electricity needs of your region, and how those needs can be addressed through energy conservation programs, local generation, and sourcing electricity from outside the region.

Distribution Planning: This consultation concentrates on the short-term plan for BPI's distribution system. The graphic below shows the various planning initiatives ongoing across Ontario's electricity system. In addition to the short-term distribution plan being discussed in this workbook, there are other planning initiatives undertaken to ensure that Ontario's system maintains reliability and works efficiently for the benefit of customers.

Electricity System Planning in Ontario



Provincial System Planning

This involves more long-term planning on how Ontario's electricity system is designed and operated.

This includes planning on:

- Provincial electricity supply mix (e.g. greening the grid and phasing out coal power generation)
- System supply and demand forecasting
- Interconnections and grid design

Regional Planning

Regional planning involves near- and medium-term plans to meet the needs of a region of the province, and ensure all key players (i.e. transmission and distribution operators) are coordinated moving forward.

This planning process is focused on considering whether conservation and local generation options have been considered, in addition to core infrastructure ("wires") solutions.

Distribution Network Planning

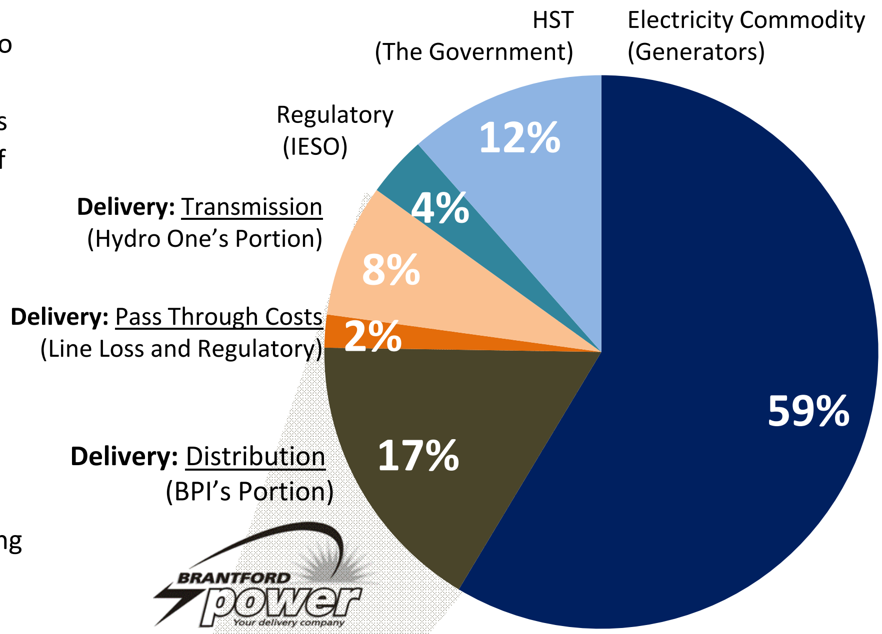
Distribution planning involves plans, both near- and longer-term, to ensure the local distribution systems have adequate infrastructure to meet required reliability and safety standards, and to otherwise meet the needs of customers.

Electricity Bills:
Understanding where your money goes

Your Electricity Bill: Every item and charge on your bill is mandated by the provincial government or regulated by the OEB. There are two distinct cost areas that make up the "Delivery " charge on your bill: ***distribution*** and ***transmission***. While BPI collects both, the transmission charge is remitted to Hydro One. The distribution charges include the portion of your bill that BPI keeps, as well as some other "pass through" charges, most of which are remitted to the IESO. The distribution charges which BPI keeps make up about 17% of the typical residential customer's (800 kWh per month) total electricity bill.

BPI's distribution rates are subject to the review and approval of the OEB. The distribution fees collected from customers cover BPI's capital investments and operating expenses.

About 17% of the average residential electricity bill goes to Brantford Power. The rest of the bill goes to power generation companies, transmission companies, the government, and regulatory agencies.



SAMPLE RESIDENTIAL MONTHLY BILL **Brantford Power Inc.**	
Account Number: 000 000 000 000 0000	
Meter Number: 00000000	
Your Electricity Charges	
Electricity	
Off-Peak @ 8.300 ¢/kWh	42.50
Mid-Peak @ 12.800 ¢/kWh	18.43
On-Peak @ 17.500 ¢/kWh	25.20
Delivery (BPI $24.47)	38.73
Regulatory Charges	5.22
Debt Retirement Charge	0.00
Debt Retirement Charge exemption saved you $5.60	
Total Electricity Charges	**$130.08**
HST	$16.91
Total Amount	**$146.99**

Current monthly distribution charges are about **$24.47 per month or 17% of the total monthly bill** for the average BPI residential customer who consumes 800 kWh of electricity per month.

In 2017, it is estimated that an additional **$4.93 per month** will be required of the average residential customer to operate, maintain, and modernize BPI's electricity distribution system.

For 2018 through 2021, it is estimated distribution rates will both increase and decrease marginally to account for inflation and the elimination of mandatory program fees associated with smart meter implementation.

By 2021, the average residential household will be paying an **estimated $5.68 more per month** on the distribution portion of their electricity bill.

Electricity 101
How Ontario's Electricity System is Regulated

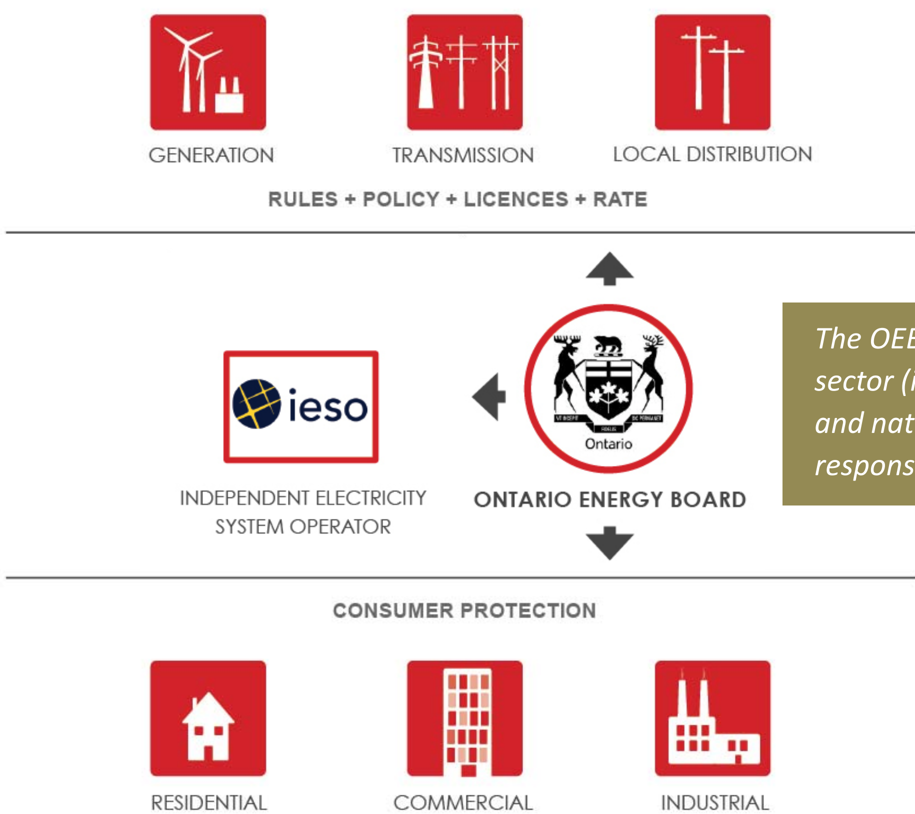
The electricity system in Ontario is regulated by the following bodies:

Ontario Ministry of Energy: The Ontario Ministry of Energy defines energy policy and sets the rules and establishes key planning priorities and mandates the role of regulatory agencies through legislation.

Ontario Energy Board: The mission of the Ontario Energy Board (OEB) is to promote a viable, sustainable and efficient energy sector that serves the public interest and assists consumers to obtain reliable energy services at a reasonable cost.

The OEB is an independent body established by legislation that sets the rules and regulations for the provincial electricity sector. One of the OEB's roles is to review the distribution plans of all electricity distributors and set the rates that they can charge customers.

Independent Electricity System Operator: The Independent Electricity System Operator (IESO) is responsible for short, medium and long-term electricity planning to ensure an adequate supply of electricity is available for Ontario residents and businesses. It operates the grid in real-time to ensure that Ontario has the electricity it needs, when and where it's needed. The IESO receives directives from the Ministry of Energy (e.g. energy supply mix, Green Energy Act), but otherwise works at arm's-length from the government.



The OEB regulates Ontario's energy sector (including both the electricity and natural gas sectors) and is responsible for consumer protection.

Electricity 101

Understanding Brantford Power's Role in Ontario's Electricity System

Ontario's electricity system is owned and operated by public, private and municipal corporations across the province. It is made up of three components: **generation**, **transmission** and **distribution**.

GENERATION

Generating facilities convert various forms of energy into electric power.

EXAMPLES

Ontario Power Generation
TransCanadaEnergy Ltd
Bruce Power
Samsung Renewable

TRANSMISSION

Transmission lines (high voltage lines) connect the power produced at generating facilities to transformer stations.

EXAMPLE

Hydro One

DISTRIBUTION

Distribution lines (at medium voltages) carry electricity to homes and businesses.

EXAMPLES

Brantford Power

Energy+ Inc.
Guelph Hydro
Horizon Utilities

RATEPAYERS

Electricity is consumed by local customers including homes and businesses. Customers of electricity distribution companies are often referred to as ratepayers.

Where does electricity come from?

In Ontario, approximately 70% of electricity is generated by **Ontario Power Generation** (OPG). This provincially-owned crown corporation has **generation** stations across the province that produce electricity from hydroelectric dams, nuclear reactors, and natural gas burning power plants.

Once electricity is generated, it must be delivered to the communities across Ontario in need of power. This happens by way of high voltage **transmission stations** and interconnected lines that serve as highways for electricity. The province has more than 30,000 kilometres of transmission lines*, owned mostly by **Hydro One**.

Brantford Power's Roles in Ontario's Electricity System

BPI is responsible for the last step of the journey: distributing electricity to customers in the region through its **distribution system**.

Every distribution system is unique with its own history and challenges. In order to better understand BPI's current system, we first have to understand all of the different components and how they impact the way in which you receive electricity when you need it.

*Source: IESO. The Power System, www.ieso.ca

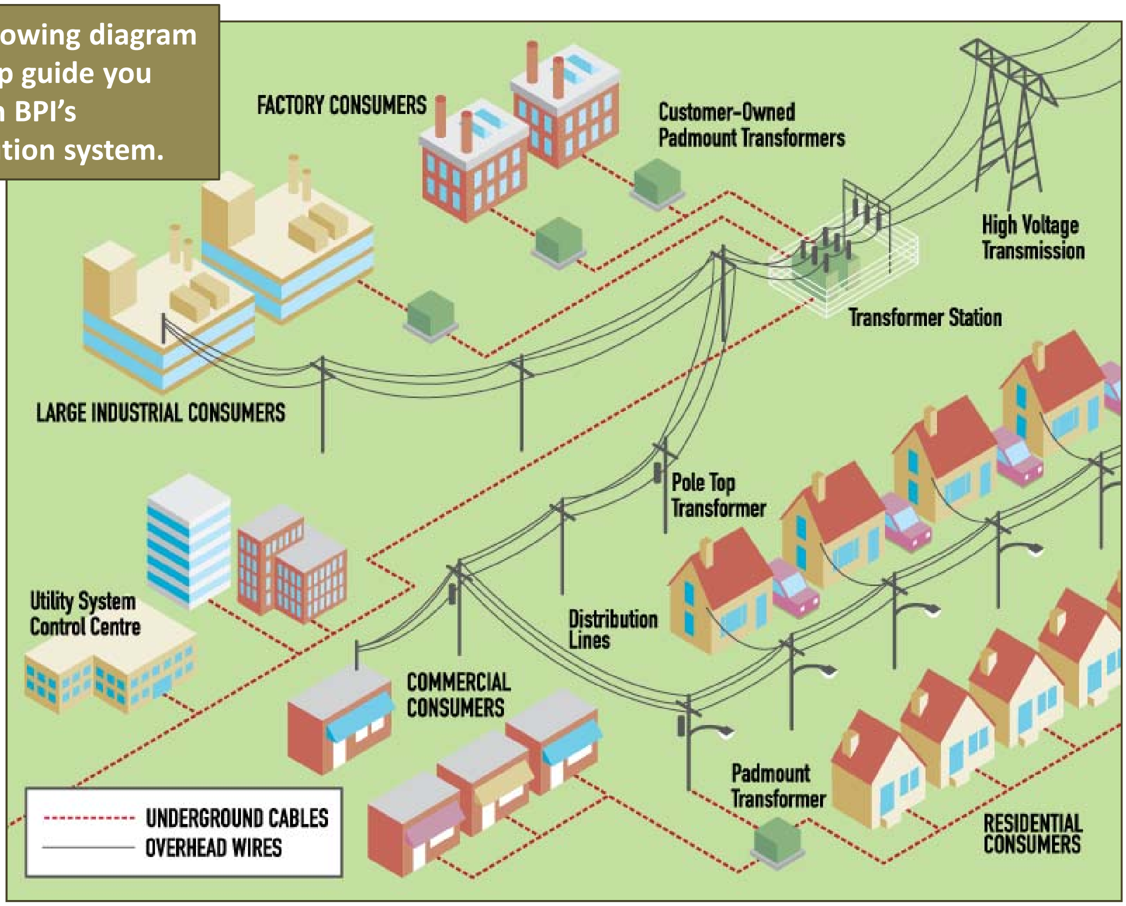
Brantford Power's Distribution System Today

Every distribution system is unique with its own history and challenges. In order to better understand BPI's distribution system, we first have to understand all of the different components and how they impact the way in which you receive electricity when you need it.

BPI's service territory covers 74 square kilometers of urban area. The distribution system contains approximately 254km of overhead wires, 229km of underground cables, and 3,447 distribution transformers.

The local distribution system receives high voltage electricity from three transformer stations: two that are owned by **Hydro One** and one that BPI jointly owns with **Energy+** (formerly Brant County Power). The high voltage electricity is then reduced and connected through 27.6kV feeder circuits. These feeder circuits are used to distribute power to customers directly from the 27.6kV system. Additional transformers are located near customers, and transform the voltage one final time to levels safe to distribute to local homes and businesses.

The following diagram will help guide you through BPI's distribution system.



High Voltage Transmission: Hydro One's high voltage transmission lines connect BPI's distribution system to electricity generating stations across the province.

Transmission Stations: Reduces high voltage electricity from transmission lines to medium voltage which is fed into BPI's distribution feeder system.

Overhead System: The overhead system includes the wires, poles, pole top transformers that are commonly seen across BPI's service territory.

Underground System: The underground system is directly buried and or installed in ducts. At certain intervals, underground service chambers (with manholes) are required to permit cables to be spliced together and to allow underground equipment such as switches to be housed.

An advantage of underground systems is that they are affected to a lesser extent by extreme weather. The disadvantage is that they are more expensive to install and maintain, and when there is a power outage, it often takes longer to locate and repair a problem compared to overhead wires.

Brantford Power's Distribution System Today
Asset Management

Managing the Distribution System

BPI adheres to the Ontario Energy Board's Distribution System Code that sets out good utility practices, minimum performance standards, and minimum inspection requirements for distribution equipment.

BPI maintains and regularly updates an **asset management plan**, which is an evolving blueprint for maintaining the utility's infrastructure and other assets to deliver an agreed standard of service. The asset management plan documents the health of thousands of individual pieces of infrastructure, equipment and assets that must work seamlessly together to deliver reliable electricity to customers.

Historically, maintaining and upgrading infrastructure and equipment has been achieved with only a moderate increase in customers' bills. The asset management plan takes into consideration both current and future system reliability needs as well as the cost implications of these upgrades. Despite best practices, there are several assets within BPI's distribution system that are nearing the end of their useful life and, as such, have been identified as candidates for replacement.

Assets*	**# in System**	**Length of Useful Life (years)**	**# with <10% Useful Life Remaining**
Transmission Stations	1	45	0
Pole Mounted Transformers	1,457	40	91
Submersible Transformers	159	35	28
Padmount Transformers	1,831	40	31
Overhead Switches	504	45	31
Padmount / Underground Switches	447	35	11
Overhead Conductor (km)	254	60	1
Underground Cable (km)	229	35	4
Poles – Wood	9,010	45	1,622
Poles – Concrete	1,011	60	0

Padmount Transformer

Pole Mounted Transformer

* Asset inventory and health assessments based on estimates as of December 31, 2015.

Customer Feedback

1. Before this consultation, how familiar were you with the various parts of the electricity system, how they work together, and which services Brantford Power is responsible for?
   - ❑ Very familiar and could explain the detail of Ontario's electricity system to others
   - ❑ Somewhat familiar, but could <u>not</u> explain all the details of Ontario's electricity system to others
   - ❑ Have heard of some of the terms and organizations mentioned in this workbook, but knew very little about Ontario's electricity system
   - ❑ Aside from receiving a bill from Brantford Power, I knew nothing about Ontario's electricity system

2. Given what you have read so far, how well do you feel Ontario's electricity system has been explained to you?
   - ❑ Very well
   - ❑ Somewhat well
   - ❑ Not very well
   - ❑ Not well at all
   - ❑ Don't know

3. Generally, how satisfied are you with the service you receive from Brantford Power?
   - ❑ Very satisfied
   - ❑ Somewhat satisfied
   - ❑ Neither satisfied nor dissatisfied
   - ❑ Somewhat dissatisfied
   - ❑ Very dissatisfied
   - ❑ Don't know

4. Is there anything in particular that Brantford Power can do to improve its service to you?

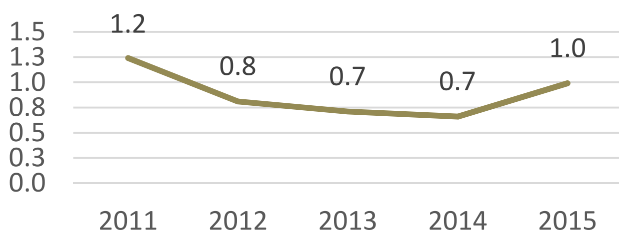
Brantford Power's Distribution System Today
System Reliability

No distribution system can deliver 100% reliable electrical service. From time-to-time, customers will experience a power service interruption. Generally, the more reliable the system, the more expensive the system is to build, operate, and maintain. As such, BPI faces a "balancing act" between system reliability and the cost of maintaining and operating the distribution system.

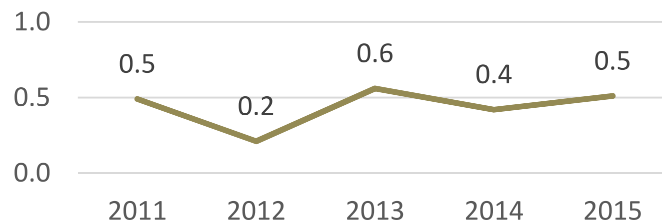
For most customers, the key test of system reliability is "do the lights stay on?" BPI tracks both the number of power service interruptions per customer and how long those outages last. The reliability indices indicate that *equipment failure* and *foreign interference* (e.g. vehicular collision with equipment or animal contact such as squirrels or racoons interfering with equipment) are two of the key contributors to customer outages.

While the number of *equipment failure* and *foreign interference* related outages has been fairly steady over the historical period, there has been an increase in the frequency of adverse weather related outages. Climate change experts indicate that adverse weather conditions are expected to increase, putting additional strain on the design and operation of the distribution system. This highlights the need for BPI to consider climate change and adverse weather on the design and operation of the distribution system.

Average # Outages per Customer per Year



Length of Outages (hours) per Customer per Year



NOTE: These figures exclude outages due to loss of supply from Hydro One's transmission grid.

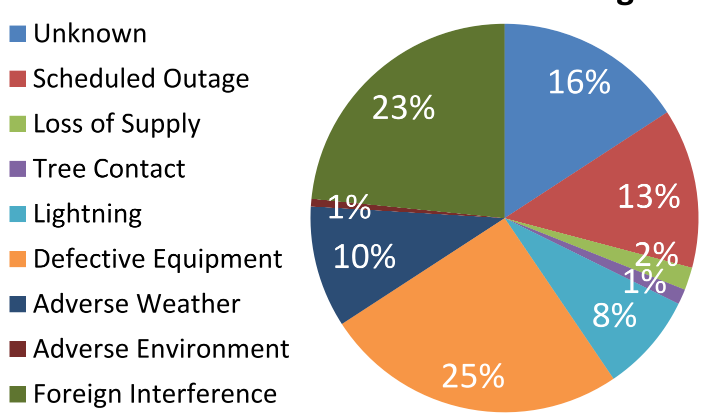
As illustrated in the table below, BPI's reliability statistics compare favourably among peer utilities:

2014 Reliability Indicator	BPI	Brant County	Cambridge	Kitchener	Wellington North	Haldimand	Burlington
Length of Outages (hours)	0.42	2.71	0.64	0.72	0.12	5.24	0.93
Average # Outages per Customer	0.66	0.92	1.33	1.03	0.11	2.62	0.87

Source: 2014 OEB Yearbook; Comparative Reliability Statistics

The outage analysis and system performance measures provide an overview of performance of the BPI distribution system during 2015. It is based on the raw data provided for incidents and outages and accumulated by the control room staff and contributes to BPI's Asset Management Plan by identifying future maintenance and capital budget priorities to enhance the reliability and performance of the distribution system.

Cause of 2015 Outages



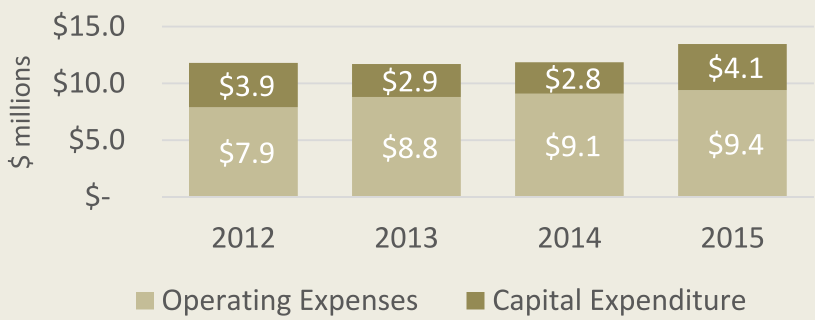
Brantford Power's Distribution System Today

What does it cost to run BPI's distribution system?

Like most businesses, BPI manages its spending in two budgets – an *operating budget* and a *capital budget*.

BPI's **operating budget** covers regularly recurring expenses such as the payroll for employees, and the maintenance of tools, equipment and assets. Its **capital budget** covers items that, when purchased, do not need to be repurchased for some time and which have lasting benefits over many years. This includes much of the equipment that is part of the distribution system, such as poles, wires, cables, transformers, major computer systems, vehicles and facilities.

Historic Operating Expenses and Capital Expenditures



Managing the distribution system requires millions of dollars in maintenance, system renewal and running the day-to-day operations. In its last fiscal year (2015), BPI's operating expenses and capital expenditures **totalled $13.5 million**.

How does Brantford Power set its budgets?

Utilities are monopolies and do not operate in competitive markets like most private businesses. Consumers cannot choose who delivers power to their homes and businesses; like it or not, BPI is the only delivery choice in Brantford. Due to their monopoly market structure, utilities are highly regulated to ensure that they are offering their customers reliable services at a reasonable price.

For most businesses, net income is determined by revenue minus expenses. To increase net income, businesses need to either increase revenues or decrease expenses. However, unlike private businesses, regulated utilities take a bottom-up approach which starts with net income, plus expenses which equal their revenue requirements.

Does BPI make a profit? Yes, a profit is built into its rate design. Like all regulated utilities in Ontario, BPI can generate a profit based on a target set by the OEB. A portion of this profit is reinvested in the business with the remainder paid out in the form of an annual dividend to its shareholder which may be transferred to the City of Brantford to fund services such as roads, parks, and other municipal programs.

Top Down Approach

Private Business
Revenue
- Cost of Goods Sold
- Operating Expenses
- Depreciation
- Interest
- Taxes
= Net Income

Bottom Up Approach

Regulated Ontario Utility
= Revenue Requirements
+ Taxes
+ Interest
+ Depreciation
- Other Revenue
+ Operating Expenses
Net Income (RoE)

Unlike typical private businesses, regulated utilities, like BPI, set their budgets based on forecasted revenue requirements needed to operate and maintain the distribution system. The cost of providing utility services are reviewed and need to be approved by the OEB.

Customer Feedback

5. In 2015, the average Brantford Power customer experienced one power outage. Do you recall how many outages you experienced in the past year?
    - ❑ None
    - ❑ One
    - ❑ Two
    - ❑ Three
    - ❑ Four
    - ❑ More than four
    - ❑ Don't know

6. How many power outages do you feel are reasonable in a year?
    - ❑ No outage is acceptable
    - ❑ One
    - ❑ Two
    - ❑ Three
    - ❑ Four
    - ❑ Five or more
    - ❑ Don't know

7. What do you feel is a reasonable duration for a power outage?
    - ❑ No outage is acceptable
    - ❑ Less than 15 minutes
    - ❑ 15 to less than 30 minutes
    - ❑ 30 minutes to less than 1 hour
    - ❑ 1 hour to less than 2 hours
    - ❑ 2 hours or more
    - ❑ Don't know

8. No distribution system can deliver perfectly reliable electricity service. There is a balancing act between reliability and the cost of running the system. Please select what statement comes closest to your point of view.
    - ❑ I would be willing to accept more and longer power outages if that meant there would be a decrease to my distribution rates on my electricity bill
    - ❑ I would be willing to pay a bit more on my distribution rates to maintain the current level of reliability
    - ❑ I would be willing to pay much more on my distribution rates to improve the level of reliability I currently receive from Brantford Power
    - ❑ Don't know

Key Pressures on the Distribution System

Community Growth Pressures

Between 1901 and 1980, the City of Brantford population grew at an average of 2.3% per year. From 1981 to 1991 the population grew at an average of 1.3% per year and from 1991 to 2011 the population grew at an average of 0.7% per year. As of the 2011 census, the population of Brantford was 93,650. According to the City of Brantford's Official Plan, the City is expected to grow to a population of approximately 139,000 by the year 2031. This will be an average growth of 2.4% per year for the next fifteen years, based on new industrial and residential development forecasted over the long-term.

This growth in required capacity, coupled with the need to replace aging equipment and modernize the grid, will require increased investments in BPI's infrastructure.

Meeting the Needs of a Growing Community

Over the past number of years, BPI has undertaken several significant programs to ensure the distribution system can meet the needs of a growing community. While much has already been done, there are many programs that are still underway.

Feeder Conversion Project: BPI has worked to upgrade all of the feeders in its distribution system to operate at a voltage level of 27.6 kV or greater. This allowed for BPI to eliminate all municipal substations within its service area, leaving only transmission connected stations to supply the feeders for distribution. This has simplified BPI's system maintenance practices, increased efficiencies, and will ultimately provide long-term savings for customers.

Regional Planning: As part of the medium-term Integrated Regional Resource Planning – which involved BPI, Brant County Power, Hydro One and the IESO – it has been determined that investments in the transmission system that feeds BPI distribution system with electricity will need to be upgraded to support future customer demand. In the next two years, BPI plans to contribute to the upgrade of the transmission system to handle the increased demand expected due to population growth.

Infrastructure Renewal: Some of BPI's electricity infrastructure which was built in the 1950s, 60s and 70s has exceeded or will exceed its useful life in the coming years. While this electrical infrastructure has served the community well, there comes a time when this equipment must be replaced. As mentioned earlier, BPI's Asset Management Plan addresses its aging infrastructure. Assets such as poles are field tested and inspected and rated so that they can enter the BPI decision-making process which determines the parts of the system get replaced first.

Key Pressures on the Distribution System

From the day-to-day events to major storms, there are a variety of ever-present pressures on BPI's operating and capital budget.

Many of these expenditures are items over which BPI has little or no control – major storms, and the implementation of Smart Meters, for example.

Other costs are associated with preventative maintenance like replacing aging equipment. BPI has already undertaken several large scale projects, and more are planned.

How does BPI determine the appropriate amount of capital spending related to existing infrastructure?

BPI monitors the health of its infrastructure very closely. It inspects 100% of the overhead distribution system for possible tree contact annually, and inspects 100% of its distribution system assets every three years.

Has BPI previously set aside funds for required upgrades?

The OEB does not allow utilities in Ontario (including BPI) to create reserve funds. If reserve funds were allowed, a utility would have to charge customers a premium on their rates in order to set money aside. Under OEB regulation, a utility can only charge customers the rate required to run the distribution system at a reliability standard set by regulatory bodies.

Paying for Brantford Power's Distribution System:
Capital Investment Drivers

BPI has developed a list of capital investment drivers and decides upon investment programs based on these key drivers.

Reliability: There are two main measures of reliability in the distribution system:

1) How often does the power go out?
2) How long does it stay out?

To achieve maintained or improved reliability, projects are developed to improve asset performance and decrease the frequency and duration of power outages.

Service Requests: BPI has a legal obligation to connect customers to its distribution system. This includes both traditional demand customers (new homes and businesses) and distributed generation customers (e.g. micro-FIT customers who have contracts to sell electricity back to the grid such as rooftop solar panels). Requests can also include system modifications to support infrastructure development by government agencies, road authorities and developers.

Support Capacity Delivery: Where there are forecasted changes in demand that will limit the ability of the system to provide consistent service delivery or where it is incapable of meeting the demand requirements, new builds or expansion is required. This is the fundamental infrastructure that allows new customers to be hooked up to the distribution system and is paid for by new customers served over time.

System Efficiency: To provide customers with the best service possible, there is always a need to improve power outage restoration capability.

Mandated Compliance: Compliance with all legal and regulatory requirements and government directives, such as compliance with the Ministry of Energy, the Ontario Energy Board, the Independent Electricity System Operator and other regulations.

Obsolescence: Asset installations that no longer align with BPI's current operating practices or current standards. This can include those assets that:

- are no longer manufactured
- lack spare parts
- cannot be accessed
- lack the ability to have maintenance performed on them
- have operational constraints or conflicts, which can result in heightened reliability and/or safety related risks

Aging or Poorly Performing Equipment: Where there is the imminent risk of failure due to age or condition deterioration, and these potential failures will result in severe reliability impacts to customers as well as potential safety risks to crew workers or to the public, remediation through refurbishment or replacement is required.

Business Support Costs: BPI is not just the local electricity distribution system itself, but a company that operates the system. As a company, it needs buildings to house its staff and vehicles, tools to service the power lines and IT systems to manage the system and customer information.

Paying for Brantford Power's Distribution System:
Capital Investments

What are the major issues Brantford Power needs to address?

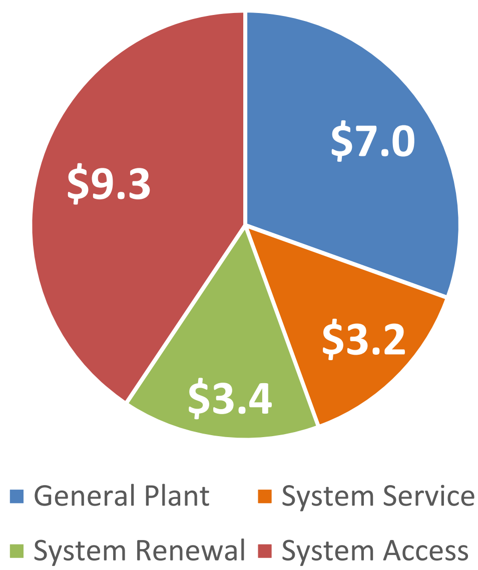
Over the years, BPI has worked hard to keep its equipment working well beyond its originally expected life, to get maximum value for money. However, BPI's key challenge still comes from the need to continue investing in system assets to keep up with growth, in addition to replacing aging equipment.

Between 2017 and 2021, the capital expenditures required to address system renewal, maintain system reliability and invest in other infrastructure priorities are estimated by BPI to be $22.8 million.

To assist them in prioritizing what needs to be replaced and by when, BPI uses an Asset Management Plan to drive replacement decisions.

Using the information provided by the Asset Management Plan, BPI plans for four types of capital investment costs:

2017-2021 Forecasted Capital Expenditures
(millions $)



System Access

Definition: Non-discretionary investments that respond to customer requests for new connections or new infrastructure development. These are high priority, "must do" projects, as BPI is mandated to connect new customers to the distribution system.

Projects Include: new subdivision and business customer connections, relocating assets based on infrastructure needs

System Renewal

Definition: These project are a mix of discretionary (planned end of life replacement) and non-discretionary (emergency replacement) investments.

Projects Include: Transmission station upgrade, underground cable replacement, overhead wire replacement, and pole replacement.

System Service

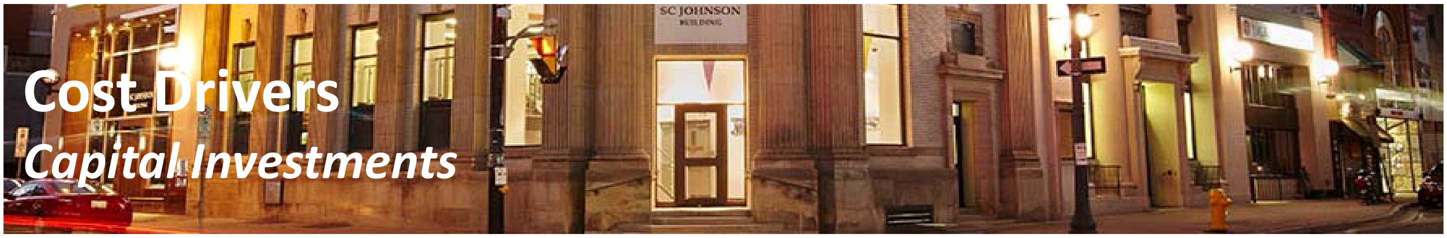
Definition: These discretionary investments consist of projects that improve system reliability and customer service.

Projects Include: automated switches, better distribution system monitoring equipment

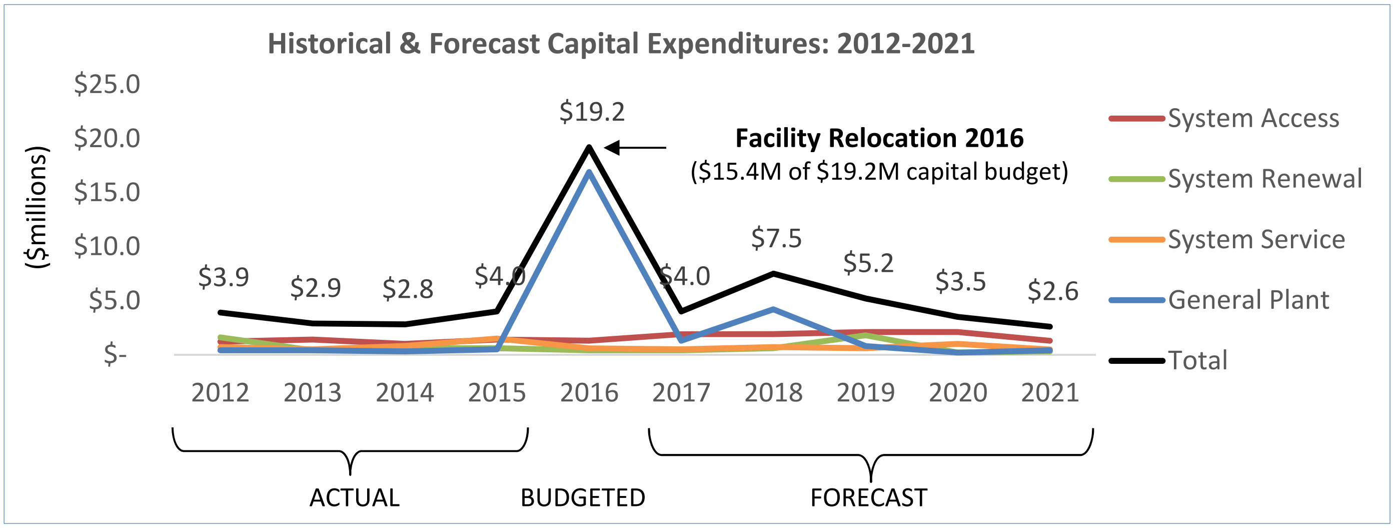
General Plant

Definition: These are discretionary investments that are needed to support the distribution system: such as tools, vehicles, buildings, and information technology (IT) systems used to manage financial and customer information. They are necessary in order to operate and maintain the distribution system efficiently and service customers.

Projects Include: Financial and customer information system and vehicle replacement



Cost Drivers
Capital Investments



Facility Relocation

BPI is not simply the operator of the local electricity distribution system; it is also an independent business that needs unique facilities to house the staff and equipment it utilizes to service its customers, including its tools, information systems, fleet, administration, warehousing and outdoor storage. Currently, BPI's staff and equipment are housed in multiple locations across Brantford, all of which are rented from either the City of Brantford or other landlords. While operating as a fragmented organization is less than ideal, BPI in its efforts to be prudent with its expenditures and as a good steward of electricity ratepayer dollars, has made the best of this arrangement.

Within the last year however, BPI has felt the pressure to explore alternatives to its current facilities arrangements. As the City of Brantford itself contemplates its own accommodation challenges, the buildings BPI currently occupies and shares with the City have either been divested of, or identified for possible repurposing. As such, the current situation is not sustainable in the near to medium-term. Sometime within the 2016-2021 period, BPI will pursue a standalone, consolidated location within its service territory; one designed to accommodate its staff and equipment and ensure the local continuity of service for its customers.

Over the past year, Brantford Power's Board of Directors, with the assistance of its leadership team, has explored the various options available and completed a formal professional analysis of those options. The options and considerations are summarized in the table below:

Options	Considerations
New Construction: Build a brand new building, to house all staff and equipment in a single location and designed to meet Brantford Power's immediate and future operational needs.	While this custom-designed building would meet all of Brantford Power's operational needs, this approach may prove to be more costly given current market conditions and limited availability of land. This solution will accommodate all staff and equipment, but is a longer-term alternative.
Acquire and Renovate: Refurbish or repurpose an existing facility that will accommodate staff and equipment in a single location that meets Brantford Power's immediate and future operational needs.	This solution provides the benefit of housing all staff and equipment in a single facility, but may not be as efficient as a custom built facility. The refurbishing of an existing facility may be a less costly alternative to the New Construction Option.

Facility Relocation: *Maintaining the Status Quo*

There is limited inventory of appropriate, single-site rental facilities within the City, and continuing to function in fragmented facilities leased form multiple landlords is not ideal from an operational perspective. This solution could ultimately cost more than existing lease agreements due to market and leasing conditions, multiple landlords and the need for significant leasehold improvements.

Economics of owning a single facility vs. renting multiple facilities

BPI currently has **$15.4 million budgeted** for its facility relocation. While this is a very large capital expenditure for BPI, this investment could save customers in the long-run as owning a facility is typically more economical that renting multiple facilities. Furthermore, customers will only see the cost of a facility relocation on their electricity bills in small, incremental installments as the investment will be depreciated over 50 years. Furthermore, in continuing to rent its work locations, BPI forgoes the ability to build its asset base and value.

Customer Feedback

9. In terms of Brantford Power's facility relocation, which option do you think your utility should pursue?
   - ❑ Build a new facility that will meet their current and foreseeable future needs.
   - ❑ Buy an existing facility and refurbish it to meet their current and foreseeable future needs.
   - ❑ Stick with the status quo and find new rental space to house equipment and staff.
   - ❑ Something else
   - ❑ Don't know

10. [*If you answered "**something else**" to the previous question*] what options do you think Brantford Power should consider in addressing their facility relocation?

11. As a company, Brantford Power needs vehicles and tools to service the power lines and IT systems to manage the system and customer information. Which of the following statements best represents your point of view?
    - ❑ Brantford Power should find ways to make do with the equipment and IT systems it already has.
    - ❑ While Brantford Power should be wise with its spending, it is important that its staff have the equipment and tools they need to manage the system safely, efficiently and reliably.
    - ❑ Don't know

12. With regards to projects focused on replacing aging equipment in poor condition, which of the following statements best represents your point of view?
    - ❑ Brantford Power should invest what it takes to replace the system's aging infrastructure to maintain system reliability, even if that increases my monthly electricity bill by a few dollars over the next few years.
    - ❑ Brantford Power should lower its investment in renewing the system's aging infrastructure to lessen the impact of any bill increase, even if that means more or longer power outages.
    - ❑ Don't know

Operating Budget Cost Drivers

Operations, Maintenance & Administration (OM&A) Expenses

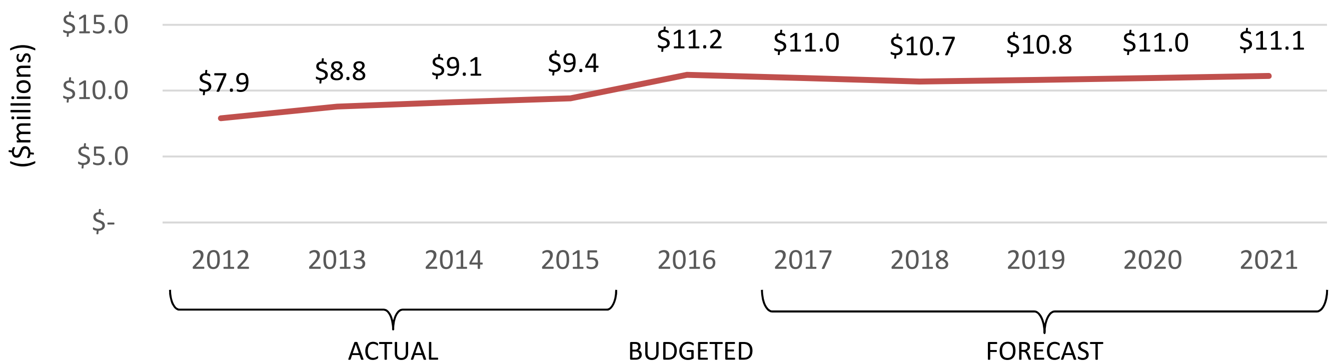
In addition to its capital budget, Brantford Power needs to consider its operating budget which also impacts customer bills.

Cost drivers contributing to the operating budget can largely be attributed to on-going maintenance and management of the distribution system. An example of this type of cost driver is BPI's vegetation program, including tree trimming, designed to lessen the impact of falling tree branches on power lines.

During the last five years, Branford Power has demonstrated its ability to minimize annual cost increases. In fact, in 2014 Brantford Power reported cost per customer levels that were 2 dollars below the level reported in 2010.

Brantford Power is continually looking for ways to improve its business processes in order to comply with the increasing responsibilities and obligations being established for local distribution companies, without negatively impacting overall costs to the customers.

Historical & Forecast OM&A Expenses: 2012-2021

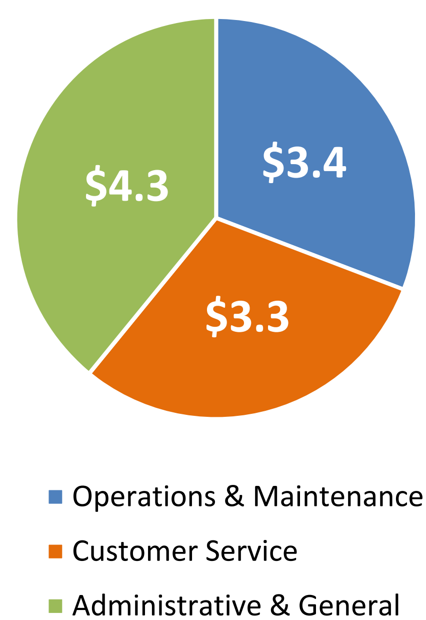


Nevertheless, the level of OM&A is expected to increase. These increases are primarily related to the following factors:

- Increases in labour costs due to negotiated increases, plus the impact of non-discretionary statutory employee benefits.
- Funding for apprentices and other technical staff necessary for succession planning, and in preparation for a number of pending retirements.
- Increased project staffing and related ongoing operating expenses related to the implementation of, and transition to replacement financial, customer service and other information systems. These expenses are necessary to improve management information and to provide enhanced self-serve functionality for customers.
- Operating expenses related to the operations of a single consolidated facility replacing the three leased premises currently in use.
- Customer engagement initiatives necessary to enable ongoing measurement of BPI's customer service performance and to obtain customer input on BPI's distribution system and other plans pursuant to OEB requirements.

2017 Forecasted OM&A Costs

($ millions)



Finding Efficiencies and Cost Savings

BPI planning, prioritization and investment processes follow good utility practices that are executed through the Distribution System Plan. Good utility practices have inherent cost savings through sound decision making, thoughtful compromises, right timing and optimum expenditure levels.

There are several other ways in which Brantford Power works to find efficiencies and cost savings in the system:

- **Asset Condition Inspections** and comprehensive data collection will provide a better understanding of each distribution infrastructure asset's stage in their lifecycle. By making use of this data we will be able to make more informed and cost effective decisions with respect to the maintenance, refurbishment and replacement of our assets.

- **Reactive maintenance**, such as fixing a pole damaged by a storm, is exponentially more costly than proactive maintenance. Proactively maintaining and replacing our distribution infrastructure will improve service and have a beneficial impact on the cost of outages to the customer – outages will be fewer and shorter in duration. A structured program will also smooth out financial rate impacts in an effort to avoid disruptive rate spikes to address the volume of distribution infrastructure reaching end-of-life.

- **The use of software** (e.g. AutoCAD Utility Design; Spidacalc) to optimize infrastructure design will reduce overdesign and ensure that current CSA standards for non-linear pole loading and structural stability are adhered to.

- **Coordinating with Telecoms** will reduce installation costs when replacing existing underground subdivision cables that are nearing end-of-life.

- In order to optimize a distribution infrastructure asset's lifecycle we must be informed. The **improved use of Geographic Information Systems** (GIS) will allow us to better capture and access important attribute data (i.e. nameplate data, condition of asset, inspection/maintenance history, etc.). This will aid in cost control by optimizing the asset's lifecycle.

- Prudent investment in **distribution automation** (e.g. remotely operated switches), as part of the Smart Grid development, will improve day to day switching operations. This will have a positive impact on improving outage restoration times, and in turn reduce the impact of outages on our customers.

- **Coordination of infrastructure inspection** with maintenance reduces operating costs. Contractors performing tree trimming and infra-red testing also carry out visual inspections of surrounding infrastructure. Reports detailing any abnormalities are generated, as required, for BPI crews to follow-up and address.

- **Purchasing approved distribution system standards** significantly reduces unit cost for standard development and equipment approvals.

- **Certain maintenance activities** (e.g. painting transformers) help extend the life of the equipment thereby deferring replacement costs.

- Reporting, GIS database management and information collected via **inspection programs are recorded electronically on mobile equipment**. This mobile network facilitates electronic transmission of information, and avoids the costly and cumbersome paper process.

- **Renewing financial, customer, and other information systems** will allow for more timely and enhanced management information to operate the business allowing for the potential of further efficiencies and productivity improvements.

Customer Feedback

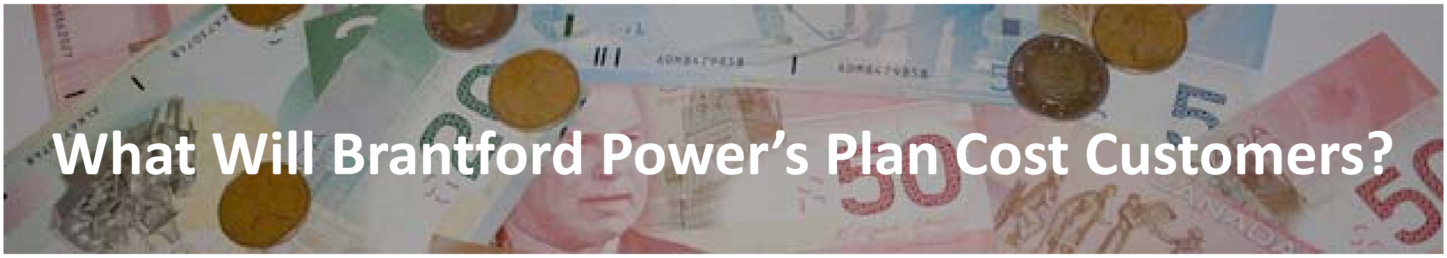
14. How well do you feel you understand the cost drivers that Brantford Power is responding to?
    - ❑ Very well
    - ❑ Somewhat well
    - ❑ Not very well
    - ❑ Not well at all
    - ❑ Don't know

15. How would you rate the job Brantford Power is doing to manage these cost drivers?
    - ❑ Very good
    - ❑ Good
    - ❑ Poor
    - ❑ Very poor
    - ❑ Don't know

16. Do any of Brantford Power's forecasted expenses or expenditures appear unreasonable to you? If so which areas appear unreasonable and why?

17. How satisfied are you with the efforts Brantford Power has made to find efficiencies and cost savings in the distribution system?
    - ❑ Very satisfied
    - ❑ Somewhat satisfied
    - ❑ Not very satisfied
    - ❑ Not at all satisfied
    - ❑ Don't know

18. Is there anything else you think Brantford Power should be doing to find efficiencies and cost savings in the distribution system?



What Will Brantford Power's Plan Cost Customers?

As mentioned earlier, BPI is funded by the distribution rates paid by its customers. Every few years, BPI is required to file a Cost of Service (COS) application with the OEB to request funding to operate and maintain the distribution system in accordance with its spending and investment plan. As part of its rate filing, BPI must submit evidence to justify the amount of funding required to safely and reliably distribute electricity to its customers.

Rate Design

BPI's last COS application was filed for rates effective **March 1, 2014**. During the years between COS applications, the OEB approves marginal increases to distribution rates (based on an allowance for inflation less an adjustment for expected efficiency gains). While BPI does its best to keep its rates low, sometimes the rates charged to customers are lower than required to adequately maintain the distribution system.

This rate setting method often results in a revenue shortfall because investments made in the years between COS applications are not recognized and thus do not allow for any adjustment to address the needs of customers. As a result, when utilities apply for new distribution rates, there is often a revenue "catch-up" in the rebased rate year to rebalance revenue requirements with actual costs associated with operating and maintaining the distribution system. Like many utilities in Ontario going through the same process, BPI estimates its rate impact will be greatest in 2017, and lesser in the subsequent years between 2018 and 2021.

Residential Bill Impact

In 2017, it is estimated that an additional **$4.93 per month** will be required of the average residential customer (monthly consumption of 800 kWh) to operate, maintain, and modernize BPI's electricity distribution system.

However, in 2018, it is estimated that distribution rates will decrease by **$0.56 per month**. This is largely due to the expiry of charges related to the provincial smart metering initiative. For 2019 through 2021, it is estimated that an additional **$0.44 per month** each year (on average over the 3 years) will be required to cover inflationary increases required to address the needs of the distribution system.

By 2021, the average residential household will be paying an **estimated $5.68 more per month** on the distribution portion of their electricity bill.

Estimated Typical Residential Annual Increase in Monthly Bill (5 year forecast)

	Year	Average Residential Bill *	Distribution Portion of Bill††	Incremental Rate Change (before HST)	% Change * (on total bill)
Current Rate	**2016**	$146.99	$24.47	--	--
Rebased Rate	**2017**	$152.56	$29.40	$4.93	3.3%
Forecast for next rate period †	**2018**	$151.92	$28.84	$(0.56)	-0.4%
	2019	$152.41	$29.27	$0.43	0.3%
	2020	$152.91	$29.71	$0.44	0.3%
	2021	$153.41	$30.15	$0.45	0.3%

† Please note that these are **preliminary estimates** and are subject to change as the rate application process progresses.
†† Estimates are calculated excluding distribution pass through charges.
* Assumes all charges on the average electricity bill remain constant at 2016 levels, aside from distribution charges.

Customer Feedback

19. From what you have read here and what you may have heard elsewhere, does Brantford Power's investment plan seem like it is going in the right direction or the wrong direction?
    - ❑ Right direction
    - ❑ Wrong direction
    - ❑ Don't know

20. How would you rate the job Brantford Power is doing when it comes to planning for the future?
    - ❑ Very good
    - ❑ Good
    - ❑ Poor
    - ❑ Very poor
    - ❑ Don't know

21. Considering what you know about the local distribution system, which of the following best represents your point of view?
    - ❑ The proposed rate increase is reasonable and I support it
    - ❑ I don't like it, but I think the proposed rate increase is necessary
    - ❑ The proposed rate increase is unreasonable and I oppose it
    - ❑ Don't know

22. Thinking about your answer to the previous question (question 21), why do you either support the proposed rate increase, think the proposed rate increase is necessary, oppose the proposed rate increase, or don't know?

Final Thoughts

Brantford Power values your feedback. This is the first time the utility has conducted a review about its upcoming investment plan in this type of format.

Overall Impression: What did you think about the workbook?

Volume of Information: Did Brantford Power provide too much information, not enough, or just the right amount?

Content Covered: Was there any content missing that you would have liked to have seen included?

Outstanding Questions: Is there anything that you would still like answered?

Suggestions for Future Consultations: How would you prefer to participate in these consultations?

Glossary

Breakers: Devices that protect the distribution system by interrupting a circuit if a higher than normal amount on power flow is detected.

Feeder Circuit: Is a wire that connects the transmission station to the broader distribution system in order to deliver electricity to customers.

General Plant: Investments in things like tools, vehicles, buildings and information technology (IT) equipment that are needed to support the distribution system.

Generation Station: A facility designed to produce electric energy from another form of energy, such as fossil fuel, nuclear, hydroelectric, geothermal, solar thermal, and wind.

Geographic Information System (GIS): A system designed to capture, store, manipulate, analyze, manage, and present all types of spatial or geographical data.

Kilovolt (kV): 1,000 volts (see "volt" below).

Kilowatt (kW): 1000 watts.

Local Distribution Company (LDC): In Ontario, these are the companies that take electricity from the transmission grid and distribute it around a community.

OM&A: Operations, Maintenance and Administration or operating budget.

Substations: Used to change AC voltages from one level to another and to switch generators, equipment and circuits and lines in and out of an electrical system.

Switches: These control the flow of electricity—they direct which supply of electricity is used and which circuits are energized. Distribution systems have switches installed at strategic locations to redirect power flows for load balancing or sectionalizing.

System Access: Projects required to respond to customer requests for new connections or new infrastructure development. These are usually a regulatory requirement to complete.

System Renewal: Projects to replace aging infrastructure in poor condition.

System Service: Primarily projects that improve reliability.

Transmission lines: Transmit high-voltage electricity from the generation source or substation to another substation in the electricity grid.

Transformer: Is an important piece of equipment that reduces the voltage of electricity from a high level to a level that can be safely distributed to your area or to your residence/business.

Underground Cable: A conductor with insulation, or a stranded conductor with or without insulation and other coverings (single-conductor cable), or a combination of conductors insulated from one another (multiple-conductor cable) with an intended use of being buried.

Volt (V): A unit of measure of the force, or 'push,' given the electrons in an electric circuit. One volt produces one ampere of current when acting on a resistance of one ohm.

Watt (W): The unit of electric power, or amount of work (J), done in a unit of time. One ampere of current flowing at a potential of one volt produces one watt of power.

Wire: A conductor wire or combination of wires not insulated from one another, suitable for carrying electric current.

ICM Appendix F:

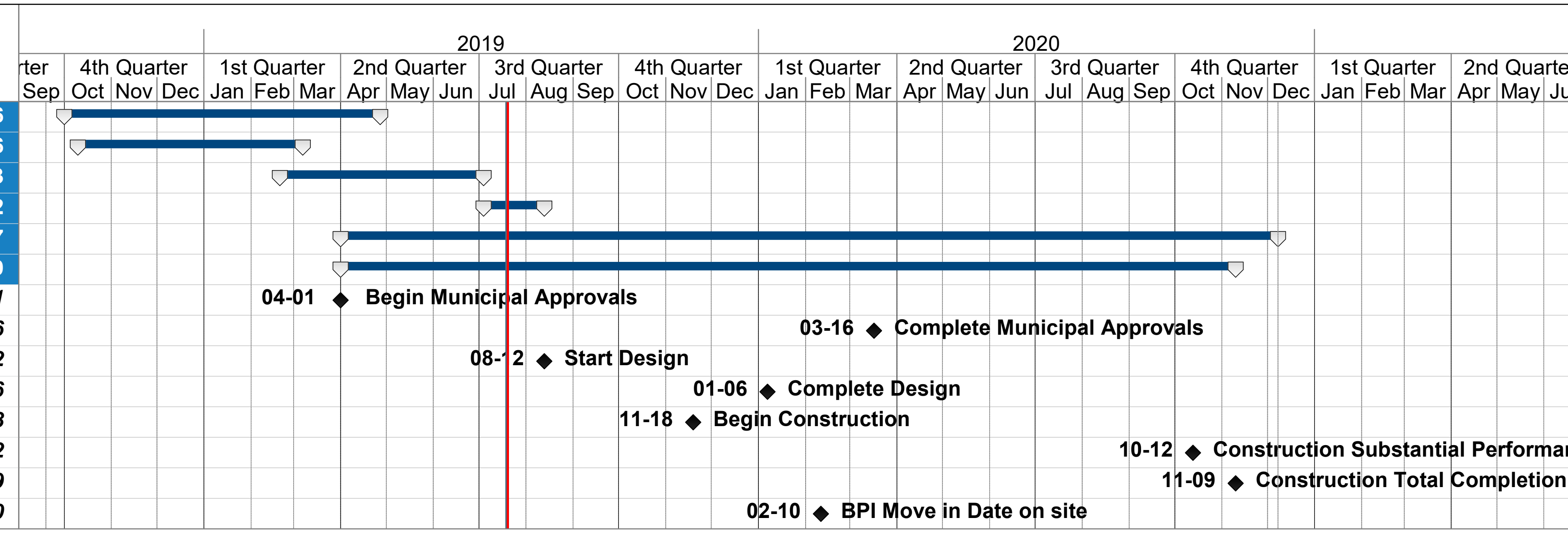
Project Timeline

Savannah Oaks Renovation & Expansion

Brantford Power Inc

Preliminary Master Schedule

ID		%	Name	Duration	Start	Finish
1	✓	100%	Real Estate Transaction	150 days	2018-10-01	2019-04-26
7	✓	100%	Due Dilligence Investigations	106 days	2018-10-10	2019-03-06
59	✓	100%	Procure Construction Manager	96 days	2019-02-20	2019-07-03
66		39%	Procure Architect	28 days	2019-07-04	2019-08-12
79		7%	Design and Construction	441 days	2019-04-01	2020-12-07
135		0%	Summary of Schedule	421 days	2019-04-01	2020-11-09
136		*0%*	*Begin Municipal Approvals*	*0 days*	*2019-04-01*	*2019-04-01*
137		*0%*	*Complete Municipal Approvals*	*0 days*	*2020-03-16*	*2020-03-16*
138		*0%*	*Start Design*	*0 days*	*2019-08-12*	*2019-08-12*
139		*0%*	*Complete Design*	*0 days*	*2020-01-06*	*2020-01-06*
140		*0%*	*Begin Construction*	*0 days*	*2019-11-18*	*2019-11-18*
141		*0%*	*Construction Substantial Performance*	*0 days*	*2020-10-12*	*2020-10-12*
142		*0%*	*Construction Total Completion*	*0 days*	*2020-11-09*	*2020-11-09*
143		*0%*	*BPI Move in Date on site*	*0 days*	*2020-02-10*	*2020-02-10*



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Page 1 of 1

Normal Task | Critical Task | Milestone | Summary Task | Baseline Plan

ICM Appendix G:

Completed ICM Model

(also submitted in Excel format).

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Note: Depending on the selections made below, certain worksheets in this workbook will be hidden.

Version 5.00

Utility Name	Brantford Power Inc.
Assigned EB Number	EB2019-0022
Name of Contact and Title	Oana Stefan, Manager of Regulatory Affairs
Phone Number	519-751-3522 x 5477
Email Address	ostefan@brantford.ca
Is this Capital Module being filed in a CoS or Price-Cap IR Application?	Price-Cap IR
Indicate the Price-Cap IR Year (1, 2, 3, 4, etc) in which Brantford Power Inc. is applying:	3
Brantford Power Inc. is applying for:	ICM Approval
Last Rebasing Year:	2017
The most recent complete year for which actual billing and load data exists	2018
Current IPI	1.50%
Strech Factor Assigned to Middle Cohort*	III
Stretch Factor Value	0.30%
Price Cap Index	1.20%

Rate Year	2020
Next OEB Scheduled Rebasing Year	2022

Based on the inputs above, the growth factor utilized in the Materiality Threshold Calculation will be determined by:

$$\frac{\text{Revenues Based on 2018 Actual Distribution Demand}}{\text{Revenues Based on 2017 Board-Approved Distribution Demand}}$$

Notes

Pale green cells represent input cells.

Pale blue cells represent drop-down lists. The applicant should select the appropriate item from the drop-down list.

White cells contain fixed values, automatically generated values or formulae.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

**As per ACM/ICM policy, the middle cohort stretch factor is applied to all ACM/ICM applications.*

OEB policies regarding rate-setting and rebasing following distributor consolidations could allow a distributor to not rebase rates for up to ten years. A distributor could also apply for and receive OEB approval to defer rebasing. If a distributor is under Price Cap IR for more than four years after rebasing and applies for an ICM, this spreadsheet will need to be adapted to accommodate those circumstances. The distributor should contact OEB staff to discuss the circumstances so that a customized model can be provided.

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Brantford Power Inc.

Select the appropriate rate classes as they appear on your most recent Board-Approved Tariff of Rates and Charges, excluding the MicroFit Class.

How many classes are on your most recent Board-Approved Tariff of Rates and Charges? **8**

Select Your Rate Classes from the **Blue Cells** below. Please ensure that a rate class is assigned to **each shaded cell.**

	Rate Class Classification
1	RESIDENTIAL
2	GENERAL SERVICE LESS THAN 50 kW
3	GENERAL SERVICE 50 TO 4,999 KW
4	EMBEDDED DISTRIBUTOR
5	SENTINEL LIGHTING
6	STREET LIGHTING
7	UNMETERED SCATTERED LOAD
8	STANDBY POWER

Ontario Energy Board

Capital Module

Applicable to ACM and ICM

Brantford Power Inc.

Input the billing determinants associated with Brantford Power Inc.'s Revenues Based on 2018 Actual Distribution Demand. Input the current approved distribution rates. Sheets 4 & 5 calculate the NUMERATOR portion of the growth factor calculation.

		2018 Actual Distribution Demand			Current Approved Distribution Rates		
Rate Class	**Units**	**Billed Customers or Connections**	**Billed kWh**	**Billed kW (if applicable)**	**Monthly Service Charge**	**Distribution Volumetric Rate kWh**	**Distribution Volumetric Rate kW**
RESIDENTIAL	$/kWh	36,595	301,310,523		23.50	0.0000	0.0000
GENERAL SERVICE LESS THAN 50 kW	$/kWh	2,822	94,728,588		30.77	0.0081	0.0000
GENERAL SERVICE 50 TO 4,999 KW	$/kW	487	535,922,956	1,447,503	236.93	0.0000	2.8643
EMBEDDED DISTRIBUTOR	$/kW	1	41,227,723	95,219	362.56	0.0000	2.0121
SENTINEL LIGHTING	$/kW	505	190,023	520	4.24	0.0000	20.3000
STREET LIGHTING	$/kW	5,771	7,191,580	22,227	1.45	0.0000	6.0789
UNMETERED SCATTERED LOAD	$/kWh	408	1,497,429		13.12	0.0091	0.0000
STANDBY POWER	$/kW				0.00	0.0000	1.7389

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Brantford Power Inc.

Calculation of pro forma 2017 Revenues. No input required.

Rate Class	2018 Actual Distribution Demand			Current Approved Distribution Rates										
	Billed Customers or Connections	Billed kWh	Billed kW (if applicable)	Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Revenues from Rates	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Total % Revenue
	A	B	C	D	E	F	G	H	I	J	K = G / J	L = H / J	M = I / J	N
RESIDENTIAL	36,595	301,310,523		23.50	0.0000	0.0000	10,319,790	0	0	10,319,790	100.0%	0.0%	0.0%	56.7%
GENERAL SERVICE LESS THAN 50 kW	2,822	94,728,588		30.77	0.0081	0.0000	1,041,995	767,302	0	1,809,297	57.6%	42.4%	0.0%	9.9%
GENERAL SERVICE 50 TO 4,999 KW	487	535,922,956	1,447,503	236.93	0.0000	2.8643	1,384,619	0	4,146,083	5,530,702	25.0%	0.0%	75.0%	30.4%
EMBEDDED DISTRIBUTOR	1	41,227,723	95,219	362.56	0.0000	2.0121	4,351	0	191,590	195,941	2.2%	0.0%	97.8%	1.1%
SENTINEL LIGHTING	505	190,023	520	4.24	0.0000	20.3000	25,694	0	10,556	36,250	70.9%	0.0%	29.1%	0.2%
STREET LIGHTING	5,771	7,191,580	22,227	1.45	0.0000	6.0789	100,415	0	135,116	235,531	42.6%	0.0%	57.4%	1.3%
UNMETERED SCATTERED LOAD	408	1,497,429		13.12	0.0091	0.0000	64,236	13,627	0	77,862	82.5%	17.5%	0.0%	0.4%
STANDBY POWER				0.00	0.0000	1.7389	0	0	0	0	0.0%	0.0%	0.0%	0.0%
Total	**46,589**	**982,068,822**	**1,565,469**				**12,941,100**	**780,928**	**4,483,345**	**18,205,373**				**100.0%**

Ontario Energy Board

Capital Module

Applicable to ACM and ICM

Brantford Power Inc.

Applicants Rate Base

Last COS Rebasing: 2017

Average Net Fixed Assets						
Gross Fixed Assets - Re-based Opening	$	108,934,858	A			
Add: CWIP Re-based Opening			B			
Re-based Capital Additions	$	3,828,988	C			
Re-based Capital Disposals	-$	230,000	D			
Re-based Capital Retirements			E			
Deduct: CWIP Re-based Closing			F			
Gross Fixed Assets - Re-based Closing	$	112,533,846	G			
Average Gross Fixed Assets				$	110,734,352	H = (A + G) / 2
Accumulated Depreciation - Re-based Opening	$	44,708,799	I			
Re-based Depreciation Expense	$	3,503,507	J			
Re-based Disposals	-$	130,000	K			
Re-based Retirements			L			
Accumulated Depreciation - Re-based Closing	$	48,082,306	M			
Average Accumulated Depreciation				$	46,395,553	N = (I + M) / 2
Average Net Fixed Assets				**$**	**64,338,800**	O = H - N
Working Capital Allowance						
Working Capital Allowance Base	$	128,865,800	P			
Working Capital Allowance Rate		7.5%	Q			
Working Capital Allowance				**$**	**9,664,935**	R = P * Q
Rate Base				**$**	**74,003,735**	S = O + R
Return on Rate Base						
Deemed ShortTerm Debt %		4.00%	T	$	2,960,149	W = S * T
Deemed Long Term Debt %		56.00%	U	$	41,442,091	X = S * U
Deemed Equity %		40.00%	V	$	29,601,494	Y = S * V
Short Term Interest		1.76%	Z	$	52,099	AC = W * Z
Long Term Interest		4.29%	AA	$	1,777,125	AD = X * AA
Return on Equity		8.78%	AB	$	2,599,011	AE = Y * AB
Return on Rate Base				**$**	**4,428,235**	AF = AC + AD + AE
Distribution Expenses						
OM&A Expenses	$	10,091,665	AG			
Amortization	$	3,389,079	AH			
Ontario Capital Tax	$	-	AI			
Grossed Up Taxes/PILs	$	504,976	AJ			
Low Voltage	$	-	AK			
Transformer Allowance	$	478,993	AL			
			AM			
			AN			
			AO			
				$	**14,464,713**	AP = SUM (AG : AO)
Revenue Offsets						
Specific Service Charges	-$	651,903	AQ			
Late Payment Charges	-$	235,599	AR			
Other Distribution Income	-$	264,212	AS			
Other Income and Deductions	-$	163,286	AT	**-$**	**1,315,000**	AU = SUM (AQ : AT)
Revenue Requirement from Distribution Rates				**$**	**17,577,948**	AV = AF + AP + AU
Rate Classes Revenue						
Rate Classes Revenue - Total (Sheet 4)				$	18,205,373	AW

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Brantford Power Inc.

Input the billing determinants associated with Brantford Power Inc.'s Revenues Based on 2017 Board-Approved Distribution Demand. This sheet calculates the DENOMINATOR portion of the growth factor calculation.
Pro forma Revenue Calculation.

	2017 Board-Approved Distribution Demand			Current Approved Distribution Rates										
Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue By Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Total % Revenue
	A	B	C	D	E	F	G	H	I	J	$K = G / J_{total}$	$L = H / J_{total}$	$M = I / J_{total}$	N
RESIDENTIAL	36,433	301,593,274		23.50	0.0000	0.0000	10,274,106	0	0	10,274,106	57.2%	0.0%	0.0%	57.2%
GENERAL SERVICE LESS THAN 50 kW	2,840	103,442,407		30.77	0.0081	0.0000	1,048,642	837,883	0	1,886,525	5.8%	4.7%	0.0%	10.5%
GENERAL SERVICE 50 TO 4,999 KW	449	496,695,575	1,342,821	236.93	0.0000	2.8643	1,276,579	0	3,846,242	5,122,821	7.1%	0.0%	21.4%	28.5%
EMBEDDED DISTRIBUTOR	2	51,013,084	139,437	362.56	0.0000	2.0121	8,701	0	280,561	289,263	0.0%	0.0%	1.6%	1.6%
SENTINEL LIGHTING	597	382,297	1,155	4.24	0.0000	20.3000	30,375	0	23,447	53,822	0.2%	0.0%	0.1%	0.3%
STREET LIGHTING	5,849	7,460,329	22,796	1.45	0.0000	6.0789	101,773	0	138,575	240,347	0.6%	0.0%	0.8%	1.3%
UNMETERED SCATTERED LOAD	425	1,405,154		13.12	0.0091	0.0000	66,912	12,787	0	79,699	0.4%	0.1%	0.0%	0.4%
STANDBY POWER				0.00	0.0000	1.7389	0	0	0	0	0.0%	0.0%	0.0%	0.0%
Total	**46,595**	**961,992,120**	**1,506,209**				**12,807,088**	**850,670**	**4,288,824**	**17,946,583**				**100.0%**

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Brantford Power Inc.

Current Revenue from Rates

This sheet is used to determine the applicant's most current allocation of revenues (after the most recent revenue to cost ratio adjustment, if applicable) to appropriately allocate the incremental revenue requirement to the classes.

	Current OEB-Approved Base Rates			2018 Actual Distribution Demand										
Rate Class	**Monthly Service Charge**	**Distribution Volumetric Rate kWh**	**Distribution Volumetric Rate kW**	**Re-based Billed Customers or Connections**	**Re-based Billed kWh**	**Re-based Billed kW**	**Current Base Service Charge Revenue**	**Current Base Distribution Volumetric Rate kWh Revenue**	**Current Base Distribution Volumetric Rate kW Revenue**	**Total Current Base Revenue**	**Service Charge % Total Revenue**	**Distribution Volumetric Rate % Total Revenue**	**Distribution Volumetric Rate % Total Revenue**	**Total % Revenue**
	A	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**	**$L = G / J_{total}$**	**$M = H / J_{total}$**	**$N = I / J_{total}$**	**O**
RESIDENTIAL	23.50	0	0	36,595	301,310,523	0	10,319,790	0	0	10,319,790	56.69%	0.00%	0.00%	56.7%
GENERAL SERVICE LESS THAN 50 kW	30.77	0.0081	0	2,822	94,728,588	0	1,041,995	767,302	0	1,809,297	5.72%	4.21%	0.00%	9.9%
GENERAL SERVICE 50 TO 4,999 KW	236.93	0	2.8643	487	535,922,956	1,447,503	1,384,619	0	4,146,083	5,530,702	7.61%	0.00%	22.77%	30.4%
EMBEDDED DISTRIBUTOR	362.56	0	2.0121	1	41,227,723	95,219	4,351	0	191,590	195,941	0.02%	0.00%	1.05%	1.1%
SENTINEL LIGHTING	4.24	0	20.3	505	190,023	520	25,694	0	10,556	36,250	0.14%	0.00%	0.06%	0.2%
STREET LIGHTING	1.45	0	6.0789	5,771	7,191,580	22,227	100,415	0	135,116	235,531	0.55%	0.00%	0.74%	1.3%
UNMETERED SCATTERED LOAD	13.12	0.0091	0	408	1,497,429	0	64,236	13,627	0	77,862	0.35%	0.07%	0.00%	0.4%
STANDBY POWER	0.00	0	1.7389	0	0	0	0	0	0	0	0.00%	0.00%	0.00%	0.0%
Total							**12,941,100**	**780,928**	**4,483,345**	**18,205,373**				**100.0%**

Ontario Energy Board

Capital Module

Applicable to ACM and ICM

Brantford Power Inc.

No Input Required.

Final Materiality Threshold Calculation

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

Cost of Service Rebasing Year		**2017**	
Price Cap IR Year in which Application is made		**3**	n
Price Cap Index		**1.20%**	PCI
Growth Factor Calculation			
Revenues Based on 2018 Actual Distribution Demand		**$18,205,373**	
Revenues Based on 2017 Board-Approved Distribution Demand		**$17,946,583**	
Growth Factor		**1.44%**	g (Note 1)
Dead Band		**10%**	
Average Net Fixed Assets			
Gross Fixed Assets Opening	$	108,934,858	
Add: CWIP Opening	$	-	
Capital Additions	$	3,828,988	
Capital Disposals	-$	230,000	
Capital Retirements	$	-	
Deduct: CWIP Closing	$	-	
Gross Fixed Assets - Closing	$	112,533,846	
Average Gross Fixed Assets	$	110,734,352	
Accumulated Depreciation - Opening	$	44,708,799	
Depreciation Expense	$	3,503,507	
Disposals	-$	130,000	
Retirements	$	-	
Accumulated Depreciation - Closing	$	48,082,306	
Average Accumulated Depreciation	$	46,395,553	
Average Net Fixed Assets	$	64,338,800	
Working Capital Allowance			
Working Capital Allowance Base	$	128,865,800	
Working Capital Allowance Rate		8%	
Working Capital Allowance	$	9,664,935	
Rate Base	**$**	**74,003,735**	RB
Depreciation	**$**	**3,503,507**	d

Threshold Value (varies by Price Cap IR Year subsequent to CoS rebasing)

Price Cap IR Year 2018	**166%**
Price Cap IR Year 2019	**168%**
Price Cap IR Year 2020	**169%**
Price Cap IR Year 2021	**171%**
Price Cap IR Year 2022	**172%**
Price Cap IR Year 2023	**174%**
Price Cap IR Year 2024	**176%**
Price Cap IR Year 2025	**178%**
Price Cap IR Year 2026	**179%**
Price Cap IR Year 2027	**181%**

Threshold CAPEX $Threshold\ Value \times d$

Price Cap IR Year 2018	**$**	**5,821,845**
Price Cap IR Year 2019	**$**	**5,874,180**
Price Cap IR Year 2020	**$**	**5,927,906**
Price Cap IR Year 2021	**$**	**5,983,061**
Price Cap IR Year 2022	**$**	**6,039,684**
Price Cap IR Year 2023	**$**	**6,097,811**
Price Cap IR Year 2024	**$**	**6,157,485**
Price Cap IR Year 2025	**$**	**6,218,746**
Price Cap IR Year 2026	**$**	**6,281,635**
Price Cap IR Year 2027	**$**	**6,346,197**

Note 1: The growth factor g is annualized, depending on the number of years between the numerator and denominator for the calculation. Typically, for ACM review in a cost of service and in the fourth year of Price Cap IR, the ratio is divided by 2 to annualize it. No division is normally required for the first three years under Price Cap IR.

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Brantford Power Inc.

Identify ALL Proposed ACM and ICM projects and related CAPEX costs in the relevant years

	Cost of Service Test Year 2017	*Price Cap IR* Year 1 2018	*Price Cap IR* Year 2 2019	*Price Cap IR* Year 3 2020
CAPEX[1]	$ 3,828,988	$ 4,322,647	$ 5,819,919	$ 20,658,628
Materiality Threshold		$ 5,821,845	$ 5,874,180	$ 5,927,906
Maximum Eligible Incremental Capital (Forecasted Capex less Threshold)		$ -	$ -	$ 14,730,722

Project Descriptions:	**Type**	**Test Year** 2017	**Year 1 2018** Proposed ACM/ICM	**Year 1 2018** Amortization Expense	**Year 1 2018** CCA	**Year 2 2019** Proposed ACM/ICM	**Year 2 2019** Amortization Expense	**Year 2 2019** CCA	**Year 3 2020** Proposed ACM/ICM	**Year 3 2020** Amortization Expense	**Year 3 2020** CCA
Building	**New ICM**								$ 15,718,146	$ 362,902	$ 512,384
Furniture/Equipment	**New ICM**								$ 415,000	$ 29,833	$ 58,100
Total Cost of ACM/ICM Projects			$ -	$ -	$ -	$ -	$ -	$ -	$ 16,133,146	$ 392,735	$ 570,484
Maximum Allowed Incremental Capital			$ -			$ -			$ 14,730,722		

1. For the Cost of Service Test Year, CAPEX refers to the CAPEX approved in the DSP. For subsequent Price CAP IR years, the CAPEX to be entered is the actual CAPEX. For the current Price Cap IR year, the CAPEX to be entered is the proposed CAPEX including any ICM/updated ACM project CAPEX for the year.

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Brantford Power Inc.

Incremental Capital Adjustment **Rate Year:** 2020

Current Revenue Requirement

Current Revenue Requirement - Total	$	17,577,948	A

Eligible Incremental Capital for ACM/ICM Recovery

	Total Claim		Eligible for ACM/ICM (Full Year Prorated Amount) *(from Sheet 10b)*	
Amount of Capital Projects Claimed	$ 16,133,146		$ 14,730,722	B
Depreciation Expense	$ 392,735		$ 358,595	C
CCA	$ 570,484		$ 520,893	V

ACM/ICM Incremental Revenue Requirement Based on Eligible Amount in Rate Year

Return on Rate Base

Incremental Capital			$	14,730,722	B
Depreciation Expense (prorated to Eligible Incremental Capital)			$	358,595	C
Incremental Capital to be included in Rate Base (average NBV in year)			$	14,551,424	D = B - C/2
	% of capital structure				
Deemed Short-Term Debt	4.0%	E	$	582,057	G = D * E
Deemed Long-Term Debt	56.0%	F	$	8,148,798	H = D * F
	Rate (%)				
Short-Term Interest	1.76%	I	$	10,244	K = G * I
Long-Term Interest	4.29%	J	$	349,438	L = H * J
Return on Rate Base - Interest			$	359,682	M = K + L
	% of capital structure				
Deemed Equity %	40.00%	N	$	5,820,570	P = D * N
	Rate (%)				
Return on Rate Base -Equity	8.78%	O	$	511,046	Q = P * O
Return on Rate Base - Total			$	870,728	R = M + Q

Amortization Expense

Amortization Expense - Incremental	C	$	358,595	S

Grossed up Taxes/PILs

Regulatory Taxable Income		O	$	511,046	T
Add Back Amortization Expense (Prorated to Eligible Incremental Capital)		S	$	358,595	U
Deduct CCA (Prorated to Eligible Incremental Capital)			$	520,893	V
Incremental Taxable Income			$	348,748	W = T + U - V
Current Tax Rate	26.5%	X			
Taxes/PILs Before Gross Up			$	92,418	Y = W * X
Grossed-Up Taxes/PILs			$	125,739	Z = Y / (1 - X)

Incremental Revenue Requirement

Return on Rate Base - Total	Q	$	870,728	AA
Amortization Expense - Total	S	$	358,595	AB
Grossed-Up Taxes/PILs	Z	$	125,739	AC
Incremental Revenue Requirement		$	1,355,062	AD = AA + AB + AC

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Brantford Power Inc.

Calculation of incremental rate rider. Choose one of the 3 options: Fixed Only Rate Rider

Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue by Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Service Charge Rate Rider
	From Sheet 7	*From Sheet 7*	*From Sheet 7*	Col C * Col I_{total}	Col D* Col I_{total}	Col E* Col I_{total}	*Col I_{total}*	*From Sheet 4*	*From Sheet 4*	*From Sheet 4*	Col F / Col K / 12
RESIDENTIAL	56.69%	0.00%	0.00%	768,123	0	0	768,123	36,595	301,310,523		1.75
GENERAL SERVICE LESS THAN 50 kW	5.72%	4.21%	0.00%	77,558	57,112	0	134,670	2,822	94,728,588		3.98
GENERAL SERVICE 50 TO 4,999 KW	7.61%	0.00%	22.77%	103,060	0	308,601	411,661	487	535,922,956	1,447,503	70.44
EMBEDDED DISTRIBUTOR	0.02%	0.00%	1.05%	324	0	14,260	14,584	1	41,227,723	95,219	1215.36
SENTINEL LIGHTING	0.14%	0.00%	0.06%	1,912	0	786	2,698	505	190,023	520	0.45
STREET LIGHTING	0.55%	0.00%	0.74%	7,474	0	10,057	17,531	5,771	7,191,580	22,227	0.25
UNMETERED SCATTERED LOAD	0.35%	0.07%	0.00%	4,781	1,014	0	5,795	408	1,497,429		1.18
STANDBY POWER	0.00%	0.00%	0.00%	0	0	0	0				0.00
Total	**71.08%**	**4.29%**	**24.63%**	**963,232**	**58,126**	**333,704**	**1,355,062**	**46,589**	**982,068,822**	**1,565,469**	
							1,355,062				
							From Sheet 11, E93				

IRM Attachment B:

Completed 2020 IRM Rate Generator Model (excel);

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2020 Filers

Quick Link

Ontario Energy Board's 2020 Electricity Distribution Rates Webpage

Version 2.0

Utility Name	Brantford Power Inc.
Assigned EB Number	EB-2019-0022
Name of Contact and Title	Oana Stefan, Manager of Regulatory Affairs
Phone Number	519-751-3522 x 5477
Email Address	ostefan@brantford.ca
We are applying for rates effective	Wednesday, January 1, 2020
Rate-Setting Method	**Price Cap IR**

1. Select the last Cost of Service rebasing year — **2017**

2. Select the year that the balances of Accounts 1588 and 1589 were last approved for disposition — **2017**
(e.g. If 2017 balances were approved for disposition in the 2019 rate application, select 2017)

3. Select the year that the balances of the remaining Group 1 DVAs were last approved for disposition — **2017**

4. Select the earliest vintage year in which there is a balance in Account 1595 — **2017**
(e.g. If 2016 is the earliest vintage year in which there is a balance in a 1595 sub-account, select 2016)

5. Did you have any Class A customers at any point during the period that the Account 1589 balance accumulated (i.e. from the year the balance was last disposed to the year requested for disposition)? — **Yes**

6. Did you have any customers classified as Class A at any point during the period where the balance in Account 1580, Sub-account CBR Class B accumulated (i.e. from the year the balance was last disposed to the year requested for disposition)? — **Yes**

7. Retail Transmission Service Rates: Brantford Power Inc. is: — **Partially Embedded** **Within** Energy+ **Distribution System(s)**
(If necessary, enter all embedded distributor names in the above green shaded cell)

8. Have you transitioned to fully fixed rates? — **Yes**

Legend

- Pale green cells represent input cells.
- Pale blue cells represent drop-down lists. The applicant should select the appropriate item from the drop-down list.
- Red cells represents flags to identify either non-matching values or incorrect user selections.
- Pale grey cell represent auto-populated RRR data.
- White cells contain fixed values, automatically generated values or formulae.

Brantford Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2019

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0020

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	23.50
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019 Applicable only for Non-RPP Customers - Approved on an Interim Basis	$/kWh	(0.0030)
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019	$/kWh	0.0005
Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis	$/kWh	(0.0020)
Rate Rider for Disposition of Capacity Based Recovery Account (2019) - effective until December 31, 2019 Applicable only for Class B Customers - Approved on an Interim Basis	$/kWh	(0.0002)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0079
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0061

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to a non residential account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	30.77
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Distribution Volumetric Rate	$/kWh	0.0081
Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019 Applicable only for Non-RPP Customers - Approved on an Interim Basis	$/kWh	(0.0030)
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019	$/kWh	0.0009
Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis	$/kWh	(0.0020)
Rate Rider for Disposition of Capacity Based Recovery Account (2019) - effective until December 31, 2019 Applicable only for Class B Customers - Approved on an Interim Basis	$/kWh	(0.0002)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0070
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0054

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

The rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

The rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	236.93
Distribution Volumetric Rate	$/kW	2.8643
Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019 Applicable only for Non-RPP Customers - Approved on an Interim Basis	$/kWh	(0.0030)
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019	$/kW	0.0766
Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 Applicable only for Non-Wholesale Market Participants - Approved on an Interim Basis	$/kW	(0.9771)
Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis	$/kW	0.2402
Rate Rider for Disposition of Capacity Based Recovery Account (2019) - effective until December 31, 2019 Applicable only for Class B Customers - Approved on an Interim Basis	$/kW	(0.0557)
Retail Transmission Rate - Network Service Rate	$/kW	2.4118
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.8282

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION

This classification applies to an electricity distributor licensed by the Ontario Energy Board that is provided electricity by means of this distributor's facilities. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Approved on an Interim Basis

Service Charge	$	362.56
Distribution Volumetric Rate	$/kW	2.0121
Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis	$/kW	0.2755
Retail Transmission Rate - Network Service Rate	$/kW	2.4118
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.8282

microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.40

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	4.24
Distribution Volumetric Rate	$/kW	20.3000
Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019 Applicable only for Non-RPP Customers - Approved on an Interim Basis	$/kWh	(0.0031)
Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis	$/kW	(0.6492)
Rate Rider for Disposition of Capacity Based Recovery Account (2019) - effective until December 31, 2019 Applicable only for Class B Customers - Approved on an Interim Basis	$/kW	(0.0544)
Retail Transmission Rate - Network Service Rate	$/kW	2.2521
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.7075

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photocells. The consumption for these customers will be based on the calculated load times the required lighting times established in the approved Ontario Energy Board street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	1.45
Distribution Volumetric Rate	$/kW	6.0789
Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019 Applicable only for Non-RPP Customers - Approved on an Interim Basis	$/kWh	(0.0030)
Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis	$/kW	(0.6505)
Rate Rider for Disposition of Capacity Based Recovery Account (2019) - effective until December 31, 2019 Applicable only for Class B Customers - Approved on an Interim Basis	$/kW	(0.0551)
Retail Transmission Rate - Network Service Rate	$/kW	2.3204
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.6878

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone boots, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information/ documentation with regard to electrical demand/consumption of the proposed unmetered load. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	13.12
Distribution Volumetric Rate	$/kWh	0.0091
Rate Rider for Disposition of Capacity Based Recovery Account (2019) - effective until December 31, 2019 Applicable only for Class B Customers - Approved on an Interim Basis	$/kWh	(0.0002)
Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis	$/kWh	(0.0022)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0042
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0054

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

STANDBY POWER SERVICE CLASSIFICATION

This classification refers to an account that has Load Displacement Generation and requires the distributor to provide back-up service. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component - Approved on an Interim Basis

Standby Charge - for a month where standby power is not provided. The charge is applied to the contracted amount (e.g. nameplate rating of the generation facility).	$/kW	1.7389

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for Transformer Losses - applied to measured demand & energy	%	(1.00)

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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Customer Administration

Easement letter	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned cheque (plus bank charges)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account

Late payment - per month	%	1.50
Late payment - per annum	%	19.56
Collection of account charge - no disconnection	$	30.00
Disconnect/reconnect at meter - during regular hours	$	65.00
Disconnect/reconnect at meter - after regular hours	$	185.00
Disconnect/reconnect at pole - during regular hours	$	185.00
Disconnect/reconnect at pole - after regular hours	$	415.00
Install/remove load control device - during regular hours	$	65.00
Install/remove load control device - after regular hours	$	185.00

Other

Temporary service install & remove - overhead - no transformer	$	500.00
Temporary service - install & remove - underground - no transformer	$	300.00
Specific charge for access to the power poles - per pole/year (with the exception of wireless attachments)	$	43.63
Meter removal without authorization	$	60.00

RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly fixed charge, per retailer	$	20.00
Monthly variable charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
up to twice a year	$	no charge
more than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.032
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0218

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2020 Filers

Please complete the following continuity schedule for the following Deferral/Variance Accounts. Enter information into green cells only. Please see instructions tab for detailed instructions on how to complete tabs 3 to 7. Column BV has been prepopulated from the latest 2.1.7 RRR filing.

Please refer to the footnotes for further instructions.

Account Descriptions	Account Number	2017 Opening Principal Amounts as of Jan 1, 2017	Transactions Debit / (Credit) during 2017	OEB-Approved Disposition during 2017	Principal Adjustments[1] during 2017	Closing Principal Balance as of Dec 31, 2017	Opening Interest Amounts as of Jan 1, 2017	Interest Jan 1 to Dec 31, 2017	OEB-Approved Disposition during 2017	Interest Adjustments[1] during 2017	Closing Interest Amounts as of Dec 31, 2017
Group 1 Accounts											
LV Variance Account	1550	0			0	0	0			0	0
Smart Metering Entity Charge Variance Account	1551	0			(9,339)	(9,339)	0			(65)	(65)
RSVA - Wholesale Market Service Charge[5]	1580	0			(1,887,082)	(1,887,082)	0			(23,022)	(23,022)
Variance WMS – Sub-account CBR Class A[5]	1580	0			0	0	0			0	0
Variance WMS – Sub-account CBR Class B[5]	1580	0			(130,936)	(130,936)	0			1,609	1,609
RSVA - Retail Transmission Network Charge	1584	0			493,804	493,804	0			10,034	10,034
RSVA - Retail Transmission Connection Charge	1586	0			122,526	122,526	0			4,402	4,402
RSVA - Power[4]	1588	0			224,693	224,693	0			16,700	16,700
RSVA - Global Adjustment[4]	1589	0			(1,176,859)	(1,176,859)	0			(23,764)	(23,764)
Disposition and Recovery/Refund of Regulatory Balances (2013)[3]	1595	0				0	0			0	0
Disposition and Recovery/Refund of Regulatory Balances (2014)[3]	1595	0				0	0			0	0
Disposition and Recovery/Refund of Regulatory Balances (2015)[3]	1595	0			(86)	(86)	0			37	37
Disposition and Recovery/Refund of Regulatory Balances (2016)[3]	1595	0			193,173	193,173	0			(206,798)	(206,798)
Disposition and Recovery/Refund of Regulatory Balances (2017)[3]	1595	0			74,627	74,627	0			41,152	41,152
Disposition and Recovery/Refund of Regulatory Balances (2018)[3]	1595	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2019)[3] *Not to be disposed of until a year after rate rider has expired and that balance has been audited*	1595	0				0	0				0
RSVA - Global Adjustment	**1589**	0	0	0	(1,176,859)	(1,176,859)	0	0	0	(23,764)	(23,764)
Total Group 1 Balance excluding Account 1589 - Global Adjustment		0	0	0	(918,620)	(918,620)	0	0	0	(155,951)	(155,951)
Total Group 1 Balance		0	0	0	(2,095,479)	(2,095,479)	0	0	0	(179,715)	(179,715)
LRAM Variance Account (only input amounts if applying for disposition of this account)	**1568**	0				0	0				0
Total including Account 1568		0	0	0	(2,095,479)	(2,095,479)	0	0	0	(179,715)	(179,715)

For all OEB-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related OEB decision.

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2020 Filers

Please complete the following continuity schedule for the following Deferral/Variance Accounts. Enter information into green cells only. Please see instructions tab for detailed instructions on how to complete tabs 3 to 7. Column BV has been prepopulated from the latest 2.1.7 RRR filing.

Please refer to the footnotes for further instructions.

		2018									
Account Descriptions	**Account Number**	**Opening Principal Amounts as of Jan 1, 2018**	**Transactions Debit / (Credit) during 2018**	**OEB-Approved Disposition during 2018**	**Principal Adjustments[1] during 2018**	**Closing Principal Balance as of Dec 31, 2018**	**Opening Interest Amounts as of Jan 1, 2018**	**Interest Jan 1 to Dec 31, 2018**	**OEB-Approved Disposition during 2018**	**Interest Adjustments[1] during 2018**	**Closing Interest Amounts as of Dec 31, 2018**
Group 1 Accounts											
LV Variance Account	1550	0				0	0				0
Smart Metering Entity Charge Variance Account	1551	(9,339)	(36,257)			(45,596)	(65)	(624)			(689)
RSVA - Wholesale Market Service Charge[5]	1580	(1,887,082)	312,719			(1,574,363)	(23,022)	(32,107)			(55,129)
Variance WMS – Sub-account CBR Class A[5]	1580	0				0	0				0
Variance WMS – Sub-account CBR Class B[5]	1580	(130,936)	(476,414)			(607,350)	1,609	(6,183)			(4,574)
RSVA - Retail Transmission Network Charge	1584	493,804	(70,770)			423,034	10,034	8,264			18,298
RSVA - Retail Transmission Connection Charge	1586	122,526	415,183			537,709	4,402	6,311			10,713
RSVA - Power[4]	1588	224,693	(585,514)		944,786	583,966	16,700	(7,110)			9,590
RSVA - Global Adjustment[4]	1589	(1,176,859)	(1,393,796)		(27,741)	(2,598,397)	(23,764)	(33,942)			(57,706)
Disposition and Recovery/Refund of Regulatory Balances (2013)[3]	1595	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2014)[3]	1595	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2015)[3]	1595	(86)				(86)	37				37
Disposition and Recovery/Refund of Regulatory Balances (2016)[3]	1595	193,173	1,725			194,898	(206,798)	3,618			(203,180)
Disposition and Recovery/Refund of Regulatory Balances (2017)[3]	1595	74,627	(63,373)			11,254	41,152	1,557			42,709
Disposition and Recovery/Refund of Regulatory Balances (2018)[3]	1595	0	(7,598)			(7,598)	0	7,508			7,508
Disposition and Recovery/Refund of Regulatory Balances (2019)[3] *Not to be disposed of until a year after rate rider has expired and that balance has been audited*	1595	0				0	0				0
RSVA - Global Adjustment	**1589**	(1,176,859)	(1,393,796)	0	(27,741)	(2,598,397)	(23,764)	(33,942)	0	0	(57,706)
Total Group 1 Balance excluding Account 1589 - Global Adjustment		(918,620)	(510,299)	0	944,786	(484,133)	(155,951)	(18,766)	0	0	(174,717)
Total Group 1 Balance		(2,095,479)	(1,904,096)	0	917,045	(3,082,529)	(179,715)	(52,708)	0	0	(232,423)
LRAM Variance Account (only input amounts if applying for disposition of this account)	**1568**	0		0		0	0				0
Total including Account 1568		(2,095,479)	(1,904,096)	0	917,045	(3,082,529)	(179,715)	(52,708)	0	0	(232,423)

For all OEB-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related OEB decision.

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Incentive Rate-setting Mechanism Rate Generator for 2020 Filers

Please complete the following continuity schedule for the following Deferral/Variance Accounts. Enter information into green cells only. Please see instructions tab for detailed instructions on how to complete tabs 3 to 7. Column BV has been prepopulated from the latest 2.1.7 RRR filing.

Please refer to the footnotes for further instructions.

		2019				Projected Interest on Dec-31-18 Balances					2.1.7 RRR
Account Descriptions	Account Number	Principal Disposition during 2019 - instructed by OEB	Interest Disposition during 2019 - instructed by OEB	Closing Principal Balances as of Dec 31, 2018 Adjusted for Disposition during 2019	Closing Interest Balances as of Dec 31, 2018 Adjusted for Disposition during 2019	Projected Interest from Jan 1, 2019 to Dec 31, 2019 on Dec 31, 2018 balance adjusted for disposition during 2019 [2]	Projected Interest from Jan 1, 2020 to Apr 30, 2020 on Dec 31, 2018 balance adjusted for disposition during 2019 [2]	Total Interest	Total Claim	Account Disposition: Yes/No?	As of Dec 31, 2018
Group 1 Accounts											
LV Variance Account	1550			0	0	0		0	0		0
Smart Metering Entity Charge Variance Account	1551	(9,339)	(239)	(36,257)	(450)	(815)		(1,265)	(37,522)		(46,284)
RSVA - Wholesale Market Service Charge[5]	1580	(1,887,082)	(58,169)	312,719	3,040	7,028		10,068	322,788		(2,241,424)
Variance WMS – Sub-account CBR Class A[5]	1580			0	0	0		0	0		0
Variance WMS – Sub-account CBR Class B[5]	1580	(130,936)	(830)	(476,414)	(3,744)	(10,707)		(14,451)	(490,865)		(611,925)
RSVA - Retail Transmission Network Charge	1584	493,804	19,231	(70,770)	(933)	(1,591)		(2,524)	(73,294)		441,330
RSVA - Retail Transmission Connection Charge	1586	122,526	6,684	415,183	4,029	9,331		13,360	428,543		548,424
RSVA - Power[4]	1588	(441,904)	8,469	1,025,870	1,121	23,056		24,177	1,050,047	Yes	(1,017,829)
RSVA - Global Adjustment[4]	1589	(1,176,858)	(45,683)	(1,421,539)	(12,023)	(31,949)		(43,972)	(1,465,511)	Yes	(2,628,362)
Disposition and Recovery/Refund of Regulatory Balances (2013)[3]	1595			0	0	0		0	0	No	0
Disposition and Recovery/Refund of Regulatory Balances (2014)[3]	1595			0	0	0		0	0	No	0
Disposition and Recovery/Refund of Regulatory Balances (2015)[3]	1595			(86)	37	(2)		35	0	No	(50)
Disposition and Recovery/Refund of Regulatory Balances (2016)[3]	1595	193,173	(203,200)	1,725	20	39		59	1,784	Yes	(8,282)
Disposition and Recovery/Refund of Regulatory Balances (2017)[3]	1595			11,254	42,709	253		42,962	54,216	Yes	53,963
Disposition and Recovery/Refund of Regulatory Balances (2018)[3]	1595			(7,598)	7,508	(171)		7,337	0	No	(91)
Disposition and Recovery/Refund of Regulatory Balances (2019)[3] *Not to be disposed of until a year after rate rider has expired and that balance has been audited*	1595			0	0	0		0	0	No	
RSVA - Global Adjustment	**1589**	(1,176,858)	(45,683)	(1,421,539)	(12,023)	(31,949)	0	(43,972)	(1,465,511)		(2,628,362)
Total Group 1 Balance excluding Account 1589 - Global Adjustment		(1,659,758)	(228,054)	1,175,625	53,337	26,422	0	79,759	1,255,696		(2,270,243)
Total Group 1 Balance		(2,836,616)	(273,737)	(245,913)	41,314	(5,527)	0	35,787	(209,815)		(4,898,605)
LRAM Variance Account (only input amounts if applying for disposition of this account)	**1568**			0	0			0	0		368,002
Total including Account 1568		(2,836,616)	(273,737)	(245,913)	41,314	(5,527)	0	35,787	(209,815)		(4,530,602)

For all OEB-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related OEB decision.

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Incentive Rate-setting Mechanism Rate Generator for 2020 Filers

Please complete the following continuity schedule for the following Deferral/Variance Accounts. Enter information into green cells only. Please see instructions tab for detailed instructions on how to complete tabs 3 to 7. Column BV has been prepopulated from the latest 2.1.7 RRR filing.

Please refer to the footnotes for further instructions.

Account Descriptions	Account Number	Variance RRR vs. 2018 Balance *(Principal + Interest)*	
Group 1 Accounts			
LV Variance Account	1550	0	
Smart Metering Entity Charge Variance Account	1551	1	Please provide an explanation of the variance in the Manager's Summary
RSVA - Wholesale Market Service Charge[5]	1580	(611,932)	The variance does not match the value in cell BV25. Please provide an explanation of the varia
Variance WMS – Sub-account CBR Class A[5]	1580	0	
Variance WMS – Sub-account CBR Class B[5]	1580	(1)	Please provide an explanation of the variance in the Manager's Summary
RSVA - Retail Transmission Network Charge	1584	(2)	Please provide an explanation of the variance in the Manager's Summary
RSVA - Retail Transmission Connection Charge	1586	2	Please provide an explanation of the variance in the Manager's Summary
RSVA - Power[4]	1588	(1,611,384)	Please provide an explanation of the variance in the Manager's Summary
RSVA - Global Adjustment[4]	1589	27,740	Please provide an explanation of the variance in the Manager's Summary
Disposition and Recovery/Refund of Regulatory Balances (2013)[3]	1595	0	
Disposition and Recovery/Refund of Regulatory Balances (2014)[3]	1595	0	
Disposition and Recovery/Refund of Regulatory Balances (2015)[3]	1595	(1)	
Disposition and Recovery/Refund of Regulatory Balances (2016)[3]	1595	(0)	
Disposition and Recovery/Refund of Regulatory Balances (2017)[3]	1595	0	
Disposition and Recovery/Refund of Regulatory Balances (2018)[3]	1595	(1)	
Disposition and Recovery/Refund of Regulatory Balances (2019)[3] *Not to be disposed of until a year after rate rider has expired and that balance has been audited*	1595	0	
RSVA - Global Adjustment	**1589**	27,740	
Total Group 1 Balance excluding Account 1589 - Global Adjustment		(1,611,393)	
Total Group 1 Balance		(1,583,653)	
LRAM Variance Account (only input amounts if applying for disposition of this account)	**1568**	368,002	Please provide an explanation of the variance in the Manager's Summary
Total including Account 1568		(1,215,650)	

For all OEB-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related OEB decision.

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Incentive Rate-setting Mechanism Rate Generator for 2020 Filers

Data on this worksheet has been populated using your most recent RRR filing.
If you have identified any issues, please contact the OEB.
Have you confirmed the accuracy of the data below? **Yes**

If a distributor uses the actual GA price to bill non-RPP Class B customers for an entire rate class, it must exclude these customers from the allocation of the GA balance and the calculation of the resulting rate riders. These rate classes are not to be charged/refunded the general GA rate rider as they did not contribute to the GA balance.

Please contact the OEB to make adjustments to the IRM rate generator for this situation.

Rate Class	Unit	Total Metered kWh	Total Metered kW	Metered kWh for Non-RPP Customers (excluding WMP)	Metered kW for Non-RPP Customers (excluding WMP)	Metered kWh for Wholesale Market Participants (WMP)	Metered kW for Wholesale Market Participants (WMP)	Total Metered kWh less WMP consumption *(if applicable)*	Total Metered kW less WMP consumption *(if applicable)*	1595 Recovery Proportion (2016) [1]	1595 Recovery Proportion (2017) [1]	1568 LRAM Variance Account Class Allocation ($ amounts)	Number of Customers for Residential and GS<50 classes[3]
RESIDENTIAL SERVICE CLASSIFICATION	kWh	301,310,523	0	11,330,957	0	0	0	301,310,523	0	-47%	63%		36,595
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	94,728,588	0	12,271,676	0	0	0	94,728,588	0	-14%	20%		2,822
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kW	535,922,956	1,447,503	492,663,110	1,328,400	6,330,357	12,258	529,592,599	1,435,245	150%	18%		
EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION	kW	41,227,723	95,219	0	0	41,227,724	95,219	(1)	0	0%	-1%		
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	190,023	520	0	0	0	0	190,023	520	0%	0%		
STREET LIGHTING SERVICE CLASSIFICATION	kW	7,191,580	22,227	7,191,580	22,227	0	0	7,191,580	22,227	0%	0%		
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	1,497,429	0	0	0	0	0	1,497,429	0	3%	0%		
STANDBY POWER SERVICE CLASSIFICATION	kW	0	0	0	0	0	0	0	0	8%	0%		
	Total	982,068,822	1,565,469	523,457,323	1,350,627	47,558,081	107,477	934,510,741	1,457,992	100%	100%	0	39,417

Threshold Test

Total Claim (including Account 1568)	($209,815)	
Total Claim for Threshold Test (All Group 1 Accounts)	($209,815)	
Threshold Test (Total claim per kWh) [2]	($0.0002)	**Claim does not meet the threshold test.**

As per Section 3.2.5 of the 2019 Filing Requirements for Electricity Distribution Rate Applications, an applicant may elect to dispose of the Group 1 account balances below the threshold. If doing so, please select YES from the adjacent drop-down cell and also indicate so in the Manager's Summary. If not, please select NO.

NO

[1] Residual Account balance to be allocated to rate classes in proportion to the recovery share as established when rate riders were implemented.

[2] The Threshold Test does not include the amount in 1568.

[3] The proportion of customers for the Residential and GS<50 Classes will be used to allocate Account 1551.

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Incentive Rate-setting Mechanism Rate Generator for 2020 Filers

No input required. This workshseet allocates the deferral/variance account balances (Group 1 and 1568) to the appropriate classes as per EDDVAR dated July 31, 2009

Allocation of Group 1 Accounts (including Account 1568)

Rate Class	% of Total kWh	% of Customer Numbers **	% of Total kWh adjusted for WMP	1550	1551	allocated based on Total less WMP 1580	1584	1586	allocated based on Total less WMP 1588	1595_(2016)	1595_(2017)	1568
RESIDENTIAL SERVICE CLASSIFICATION	30.7%	92.8%	32.2%									0
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	9.6%	7.2%	10.1%									0
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	54.6%	0.0%	56.7%									0
EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION	4.2%	0.0%	0.0%									0
SENTINEL LIGHTING SERVICE CLASSIFICATION	0.0%	0.0%	0.0%									0
STREET LIGHTING SERVICE CLASSIFICATION	0.7%	0.0%	0.8%									0
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	0.2%	0.0%	0.2%									0
STANDBY POWER SERVICE CLASSIFICATION	0.0%	0.0%	0.0%									0
Total	100.0%	100.0%	100.0%	0	0	0	0	0	0	0	0	0

*** Used to allocate Account 1551 as this account records the variances arising from the Smart Metering Entity Charges to Residential and GS<50 customers.*

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Incentive Rate-setting Mechanism Rate Generator for 2020 Filers

Input required at cells C13 and C14. This workshseet calculates rate riders related to the Deferral/Variance Account Disposition (if applicable) and rate riders for Account 1568. Rate Riders will not be generated for the microFIT class.

Default Rate Rider Recovery Period (in months)	12	
DVA Proposed Rate Rider Recovery Period (in months)	12	Rate Rider Recovery to be used below
LRAM Proposed Rate Rider Recovery Period (in months)	12	Rate Rider Recovery to be used below

Rate Class	Unit	Total Metered kWh	Metered kW or kVA	Total Metered kWh less WMP consumption	Total Metered kW less WMP consumption	Allocation of Group 1 Account Balances to All Classes [2]	Allocation of Group 1 Account Balances to Non-WMP Classes Only (If Applicable) [2]	Deferral/Variance Account Rate Rider [2]	Deferral/Variance Account Rate Rider for Non-WMP (if applicable) [2]	Account 1568 Rate Rider	Revenue Reconcila
RESIDENTIAL SERVICE CLASSIFICATION	kWh	301,310,523	0	301,310,523	0	0		0.0000	0.0000	0.0000	
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	94,728,588	0	94,728,588	0	0		0.0000	0.0000	0.0000	
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kW	535,922,956	1,447,503	529,592,599	1,435,245	0		0.0000	0.0000	0.0000	
EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION	kW	41,227,723	95,219	(1)	0	0		0.0000	0.0000	0.0000	
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	190,023	520	190,023	520	0		0.0000	0.0000	0.0000	
STREET LIGHTING SERVICE CLASSIFICATION	kW	7,191,580	22,227	7,191,580	22,227	0		0.0000	0.0000	0.0000	
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	1,497,429	0	1,497,429	0	0		0.0000	0.0000	0.0000	
STANDBY POWER SERVICE CLASSIFICATION	kW	0	0	0	0	0		0.0000	0.0000	0.0000	
											0.00

[1] When calculating the revenue reconciliation for distributors with Class A customers, the balances of sub-account 1580-CBR Class B will not be taken into consideration if there are Class A customers since the rate riders, if any, are calculated separately.
[2] Only for rate classes with WMP customers are the Deferral/Variance Account Rate Riders for Non-WMP (column H and J) calculated separately. For all rate classes without WMP customers, balances in account 1580 and 1588 are included in column G and disposed through a combined Deferral/Variance Account and Rate Rider.

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Incentive Rate-setting Mechanism Rate Generator for 2020 Filers

Summary - Sharing of Tax Change Forecast Amounts

	2017	2020
OEB-Approved Rate Base	$ 74,003,734	$ 74,003,734
OEB-Approved Regulatory Taxable Income	$ 1,400,591	$ 1,400,591
Federal General Rate		15.0%
Federal Small Business Rate		9.0%
Federal Small Business Rate (calculated effective rate)[1,2]		15.0%
Ontario General Rate		11.5%
Ontario Small Business Rate		3.5%
Ontario Small Business Rate (calculated effective rate)[1,2]		11.5%
Federal Small Business Limit		$ 500,000
Ontario Small Business Limit		$ 500,000
Federal Taxes Payable		$ 210,089
Provincial Taxes Payable		$ 161,068
Federal Effective Tax Rate		15.0%
Provincial Effective Tax Rate		11.5%
Combined Effective Tax Rate	26.5%	26.5%
Total Income Taxes Payable	$ 371,157	$ 371,157
OEB-Approved Total Tax Credits (enter as positive number)	$ -	$ -
Income Tax Provision	$ 371,157	$ 371,157
Grossed-up Income Taxes	$ 504,975	$ 504,975
Incremental Grossed-up Tax Amount		$ -
Sharing of Tax Amount (50%)		**$ -**

Notes

1. Regarding the small business deduction, if applicable,
   a. If taxable capital exceeds $15 million, the small business rate will not be applicable.
   b. If taxable capital is below $10 million, the small business rate would be applicable.
   c. If taxable capital is between $10 million and $15 million, the appropriate small business rate will be calculated.

2. The OEB's proxy for taxable capital is rate base.

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Incentive Rate-setting Mechanism Rate Generator for 2020 Filers

Calculation of Rebased Revenue Requirement and Allocation of Tax Sharing Amount. Enter data from the last OEB-Approved Cost of Service application in columns C through H.

As per Chapter 3 Filing Requirements, shared tax rate riders are based on a 1 year disposition.

Rate Class		Re-based Billed Customers or Connections	Re-based Billed kWh	Re-based Billed kW	Re-based Service Charge	Re-based Distribution Volumetric Rate kWh	Re-based Distribution Volumetric Rate kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Revenue Requirement from Rates	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Total % Revenue
RESIDENTIAL SERVICE CLASSIFICATION	kWh							0	0	0	0	0.0%	0.0%	0.0%	0.0%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh							0	0	0	0	0.0%	0.0%	0.0%	0.0%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kW							0	0	0	0	0.0%	0.0%	0.0%	0.0%
EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION	kW							0	0	0	0	0.0%	0.0%	0.0%	0.0%
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW							0	0	0	0	0.0%	0.0%	0.0%	0.0%
STREET LIGHTING SERVICE CLASSIFICATION	kW							0	0	0	0	0.0%	0.0%	0.0%	0.0%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh							0	0	0	0	0.0%	0.0%	0.0%	0.0%
STANDBY POWER SERVICE CLASSIFICATION	kW							0	0	0	0	0.0%	0.0%	0.0%	0.0%
Total		0	0	0				0	0	0	0				0.0%

Rate Class		Total kWh (most recent RRR filing)	Total kW (most recent RRR filing)	Allocation of Tax Savings by Rate Class	Distribution Rate Rider	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	301,310,523		0	0.00	$/customer
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	94,728,588		0	0.0000	kWh
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kW	535,922,956	1,447,503	0	0.0000	kW
EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION	kW	41,227,723	95,219	0	0.0000	kW
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	190,023	520	0	0.0000	kW
STREET LIGHTING SERVICE CLASSIFICATION	kW	7,191,580	22,227	0	0.0000	kW
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	1,497,429		0	0.0000	kWh
STANDBY POWER SERVICE CLASSIFICATION	kW			0	0.0000	kW
Total		982,068,822	1,565,469	$0		

Incentive Rate-setting Mechanism Rate Generator for 2020 Filers

Columns E and F have been populated with data from the most recent RRR filing. Rate classes that have more than one Network or Connection charge will notice that the cells are highlighted in green and unlocked.
If the data needs to be modified, please make the necessary adjustments and note the changes in your manager's summary. As well, the Loss Factor has been imported from Tab 2.

Rate Class	Rate Description	Unit	Rate	Non-Loss Adjusted Metered kWh	Non-Loss Adjusted Metered kW	Applicable Loss Factor	Loss Adjusted Billed kWh
Residential Service Classification	Retail Transmission Rate - Network Service Rate	$/kWh	0.0079	301,310,523	0	1.0320	310,952,460
Residential Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0061	301,310,523	0	1.0320	310,952,460
General Service Less Than 50 kW Service Classification	Retail Transmission Rate - Network Service Rate	$/kWh	0.0070	94,728,588	0	1.0320	97,759,903
General Service Less Than 50 kW Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0054	94,728,588	0	1.0320	97,759,903
General Service 50 To 4,999 kW Service Classification	Retail Transmission Rate - Network Service Rate	$/kW	2.4118	535,922,956	1,447,503		
General Service 50 To 4,999 kW Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.8282	535,922,956	1,447,503		
Embedded Distributor Service Classification	Retail Transmission Rate - Network Service Rate	$/kW	2.4118	41,227,723	95,219		
Embedded Distributor Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.8282	41,227,723	95,219		
Sentinel Lighting Service Classification	Retail Transmission Rate - Network Service Rate	$/kW	2.2521	190,023	520		
Sentinel Lighting Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.7075	190,023	520		
Street Lighting Service Classification	Retail Transmission Rate - Network Service Rate	$/kW	2.3204	7,191,580	22,227		
Street Lighting Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.6878	7,191,580	22,227		
Unmetered Scattered Load Service Classification	Retail Transmission Rate - Network Service Rate	$/kWh	0.0042	1,497,429	0	1.0320	1,545,347
Unmetered Scattered Load Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0054	1,497,429	0	1.0320	1,545,347

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Incentive Rate-setting Mechanism Rate Generator for 2020 Filers

Uniform Transmission Rates	Unit	2018	2019 (Jan 1 - June 30)	2019 (July 1 - Dec 31)	2020
Rate Description		**Rate**	**Rate**	**Rate**	**Rate**
Network Service Rate	kW	$ 3.61	$ 3.71	$ 3.83	$ 3.83
Line Connection Service Rate	kW	$ 0.95	$ 0.94	$ 0.96	$ 0.96
Transformation Connection Service Rate	kW	$ 2.34	$ 2.25	$ 2.30	$ 2.30

Hydro One Sub-Transmission Rates	Unit	2018	2019 (Jan 1 - June 30)	2019 (July 1 - Dec 31)	2020
Rate Description		**Rate**	**Rate**	**Rate**	**Rate**
Network Service Rate	kW	$ 3.1942	$ 3.1942	$ 3.2915	$ 3.2915
Line Connection Service Rate	kW	$ 0.7710	$ 0.7710	$ 0.7877	$ 0.7877
Transformation Connection Service Rate	kW	$ 1.7493	$ 1.7493	$ 1.9755	$ 1.9755
Both Line and Transformation Connection Service Rate	kW	$ 2.5203	$ 2.5203	$ 2.7632	$ 2.7632

If needed, add extra host here. (I)	Unit	2018	2019	2020
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW		$ 2.66	$ 2.66
Line Connection Service Rate	kW		$ 1.67	$ 1.67
Transformation Connection Service Rate	kW			
Both Line and Transformation Connection Service Rate	kW	$ -	$ 1.67	$ 1.67

If needed, add extra host here. (II)	Unit	2018	2019	2020
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW			
Line Connection Service Rate	kW			
Transformation Connection Service Rate	kW			
Both Line and Transformation Connection Service Rate	kW	$ -	$ -	$ -

		Historical 2018	Current 2019	Forecast 2020
Low Voltage Switchgear Credit (if applicable, enter as a negative value)	$			

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2020 Filers

In the green shaded cells, enter billing detail for wholesale transmission for the same reporting period as the billing determinants on Tab 10. For Hydro One Sub-transmission Rates, if you are charged a combined Line and Transformer connection rate, please ensure that both the Line Connection and Transformation Connection columns are completed.
If any of the Hydro One Sub-transmission rates (column E, I and M) are highlighted in red, please double check the billing data entered in "Units Billed" and "Amount" columns. The highlighted rates do not match the Hydro One Sub-transmission rates approved for that time period. If data has been entered correctly, please provide explanation for the discrepancy in rates.

IESO	Network			Line Connection			Transformation Connection			Total Connection
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	150,244	$3.61	$ 542,381	155,718	$0.95	147,932	123,560	$2.34	$ 289,130	$ 437,063
February	140,250	$3.61	$ 506,303	144,858	$0.95	137,615	114,429	$2.34	$ 267,764	$ 405,379
March	131,349	$3.61	$ 474,170	138,060	$0.95	131,157	105,599	$2.34	$ 247,102	$ 378,259
April	130,075	$3.61	$ 469,571	134,091	$1.17	156,813	102,221	$3.01	$ 307,748	$ 464,560
May	175,856	$3.61	$ 634,840	180,206	$0.95	171,196	140,320	$2.34	$ 328,349	$ 499,545
June	164,935	$3.61	$ 595,415	208,857	$0.95	198,414	152,964	$2.34	$ 357,936	$ 556,350
July	195,251	$3.61	$ 704,856	198,871	$0.95	188,927	156,627	$2.34	$ 366,507	$ 555,435
August	187,250	$3.61	$ 675,973	188,543	$0.95	179,116	147,017	$2.34	$ 344,020	$ 523,136
September	189,612	$3.61	$ 684,499	192,601	$0.95	182,971	149,907	$2.34	$ 350,782	$ 533,753
October	144,959	$3.61	$ 523,302	149,277	$0.95	141,813	117,382	$2.34	$ 274,674	$ 416,487
November	142,746	$3.61	$ 515,313	154,256	$0.95	146,543	115,310	$2.34	$ 269,825	$ 416,369
December	135,269	$3.61	$ 488,321	147,233	$0.95	139,871	107,017	$2.34	$ 250,420	$ 390,291
Total	1,887,796	$ 3.61	$ 6,814,944	1,992,571	$ 0.96	$ 1,922,369	1,532,353	$ 2.38	$ 3,654,257	$ 5,576,625

Hydro One	Network			Line Connection			Transformation Connection			Total Connection
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January		$0.0000			$0.0000			$0.0000		$ -
February		$0.0000			$0.0000			$0.0000		$ -
March		$0.0000			$0.0000			$0.0000		$ -
April		$0.0000			$0.0000			$0.0000		$ -
May		$0.0000			$0.0000			$0.0000		$ -
June		$0.0000			$0.0000			$0.0000		$ -
July		$0.0000			$0.0000			$0.0000		$ -
August		$0.0000			$0.0000			$0.0000		$ -
September		$0.0000			$0.0000			$0.0000		$ -
October		$0.0000			$0.0000			$0.0000		$ -
November		$0.0000			$0.0000			$0.0000		$ -
December		$0.0000			$0.0000			$0.0000		$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Add Extra Host Here (I) (if needed)	Network			Line Connection			Transformation Connection			Total Connection
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	14	$ 2.3697	$ 32	14	$ 1.2298	$ 17		$ -		$ 17
February	13	$ 2.3695	$ 31	13	$ 1.2302	$ 16		$ -		$ 16
March	23	$ 2.3695	$ 53	23	$ 1.2300	$ 28		$ -		$ 28
April	22	$ 2.3693	$ 51	23	$ 1.2302	$ 28		$ -		$ 28
May	118	$ 2.3694	$ 281	133	$ 1.2301	$ 164		$ -		$ 164
June	238	$ 2.3644	$ 562	292	$ 1.2949	$ 378		$ -		$ 378
July	218	$ 2.3644	$ 516	293	$ 1.2949	$ 380		$ -		$ 380
August	202	$ 2.3644	$ 477	274	$ 1.2949	$ 355		$ -		$ 355
September	133	$ 2.3644	$ 314	261	$ 1.2949	$ 338		$ -		$ 338
October	97	$ 2.3644	$ 230	103	$ 1.2949	$ 133		$ -		$ 133
November	14	$ 2.3648	$ 33	15	$ 1.2948	$ 20		$ -		$ 20
December	13	$ 2.3645	$ 32	13	$ 1.2947	$ 17		$ -		$ 17
Total	1,104	$ 2.37	$ 2,612	1,457	$ 1.29	$ 1,874	-	$ -	$ -	$ 1,874

Add Extra Host Here (II) (if needed)	Network			Line Connection			Transformation Connection			Total Connection
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January		$ -			$ -			$ -		$ -
February		$ -			$ -			$ -		$ -
March		$ -			$ -			$ -		$ -
April		$ -			$ -			$ -		$ -
May		$ -			$ -			$ -		$ -
June		$ -			$ -			$ -		$ -
July		$ -			$ -			$ -		$ -
August		$ -			$ -			$ -		$ -
September		$ -			$ -			$ -		$ -
October		$ -			$ -			$ -		$ -
November		$ -			$ -			$ -		$ -
December		$ -			$ -			$ -		$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Total	Network			Line Connection			Transformation Connection			Total Connection
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	150,258	$ 3.6099	$ 542,413	155,732	$ 0.9500	$ 147,949	123,560	$ 2.3400	$ 289,130	$ 437,080
February	140,263	$ 3.6099	$ 506,334	144,871	$ 0.9500	$ 137,631	114,429	$ 2.3400	$ 267,764	$ 405,395
March	131,372	$ 3.6098	$ 474,223	138,083	$ 0.9500	$ 131,185	105,599	$ 2.3400	$ 247,102	$ 378,286
April	130,097	$ 3.6098	$ 469,622	134,114	$ 1.1695	$ 156,841	102,221	$ 3.0106	$ 307,748	$ 464,588
May	175,974	$ 3.6092	$ 635,121	180,339	$ 0.9502	$ 171,360	140,320	$ 2.3400	$ 328,349	$ 499,708
June	165,173	$ 3.6082	$ 595,977	209,149	$ 0.9505	$ 198,792	152,964	$ 2.3400	$ 357,936	$ 556,728
July	195,469	$ 3.6086	$ 705,372	199,164	$ 0.9505	$ 189,307	156,627	$ 2.3400	$ 366,507	$ 555,814
August	187,452	$ 3.6087	$ 676,450	188,817	$ 0.9505	$ 179,471	147,017	$ 2.3400	$ 344,020	$ 523,491
September	189,745	$ 3.6091	$ 684,814	192,862	$ 0.9505	$ 183,308	149,907	$ 2.3400	$ 350,782	$ 534,091
October	145,056	$ 3.6092	$ 523,532	149,380	$ 0.9502	$ 141,946	117,382	$ 2.3400	$ 274,674	$ 416,620
November	142,760	$ 3.6099	$ 515,346	154,271	$ 0.9500	$ 146,563	115,310	$ 2.3400	$ 269,825	$ 416,388
December	135,282	$ 3.6099	$ 488,353	147,246	$ 0.9500	$ 139,889	107,017	$ 2.3400	$ 250,420	$ 390,309
Total	1,888,900	$ 3.61	$ 6,817,556	1,994,028	$ 0.97	$ 1,924,242	1,532,353	$ 2.38	$ 3,654,257	$ 5,578,499

Low Voltage Switchgear Credit (if applicable) $ -

Total including deduction for Low Voltage Switchgear Credit $ 5,578,499

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2020 Filers

The purpose of this sheet is to calculate the expected billing when current 2019 Uniform Transmission Rates are applied against historical 2018 transmission units.

IESO	Network			Line Connection			Transformation Connection			Total Connection
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	150,244	$ 3.7100	$ 557,405	155,718	$ 0.9400	$ 146,375	123,560	$ 2.2500	$ 278,010	$ 424,385
February	140,250	$ 3.7100	$ 520,328	144,858	$ 0.9400	$ 136,167	114,429	$ 2.2500	$ 257,465	$ 393,632
March	131,349	$ 3.7100	$ 487,305	138,060	$ 0.9400	$ 129,776	105,599	$ 2.2500	$ 237,598	$ 367,374
April	130,075	$ 3.7100	$ 482,578	134,091	$ 0.9400	$ 126,046	102,221	$ 2.2500	$ 229,997	$ 356,043
May	175,856	$ 3.7100	$ 652,426	180,206	$ 0.9400	$ 169,394	140,320	$ 2.2500	$ 315,720	$ 485,114
June	164,935	$ 3.7100	$ 611,909	208,857	$ 0.9400	$ 196,326	152,964	$ 2.2500	$ 344,169	$ 540,495
July	195,251	$ 3.8300	$ 747,811	198,871	$ 0.9600	$ 190,916	156,627	$ 2.3000	$ 360,242	$ 551,158
August	187,250	$ 3.8300	$ 717,168	188,543	$ 0.9600	$ 181,001	147,017	$ 2.3000	$ 338,139	$ 519,140
September	189,612	$ 3.8300	$ 726,214	192,601	$ 0.9600	$ 184,897	149,907	$ 2.3000	$ 344,786	$ 529,683
October	144,959	$ 3.8300	$ 555,193	149,277	$ 0.9600	$ 143,306	117,382	$ 2.3000	$ 269,979	$ 413,285
November	142,746	$ 3.8300	$ 546,717	154,256	$ 0.9600	$ 148,086	115,310	$ 2.3000	$ 265,213	$ 413,299
December	135,269	$ 3.8300	$ 518,080	147,233	$ 0.9600	$ 141,344	107,017	$ 2.3000	$ 246,139	$ 387,483
Total	1,887,796	$ 3.77	$ 7,123,134	1,992,571	$ 0.95	$ 1,893,632	1,532,353	$ 2.28	$ 3,487,457	$ 5,381,090

Hydro One	Network			Line Connection			Transformation Connection			Total Connection
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	-	$ 3.1942	$ -	-	$ 0.7710	$ -	-	$ 1.7493	$ -	$ -
February	-	$ 3.1942	$ -	-	$ 0.7710	$ -	-	$ 1.7493	$ -	$ -
March	-	$ 3.1942	$ -	-	$ 0.7710	$ -	-	$ 1.7493	$ -	$ -
April	-	$ 3.1942	$ -	-	$ 0.7710	$ -	-	$ 1.7493	$ -	$ -
May	-	$ 3.1942	$ -	-	$ 0.7710	$ -	-	$ 1.7493	$ -	$ -
June	-	$ 3.1942	$ -	-	$ 0.7710	$ -	-	$ 1.7493	$ -	$ -
July	-	$ 3.2915	$ -	-	$ 0.7877	$ -	-	$ 1.9755	$ -	$ -
August	-	$ 3.2915	$ -	-	$ 0.7877	$ -	-	$ 1.9755	$ -	$ -
September	-	$ 3.2915	$ -	-	$ 0.7877	$ -	-	$ 1.9755	$ -	$ -
October	-	$ 3.2915	$ -	-	$ 0.7877	$ -	-	$ 1.9755	$ -	$ -
November	-	$ 3.2915	$ -	-	$ 0.7877	$ -	-	$ 1.9755	$ -	$ -
December	-	$ 3.2915	$ -	-	$ 0.7877	$ -	-	$ 1.9755	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Add Extra Host Here (I)	Network			Line Connection			Transformation Connection			Total Connection
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	14	$ 2.6625	$ 36	14	$ 1.6731	$ 23	-	$ -	$ -	$ 23
February	13	$ 2.6625	$ 35	13	$ 1.6731	$ 22	-	$ -	$ -	$ 22
March	23	$ 2.6625	$ 60	23	$ 1.6731	$ 38	-	$ -	$ -	$ 38
April	22	$ 2.6625	$ 57	23	$ 1.6731	$ 38	-	$ -	$ -	$ 38
May	118	$ 2.6625	$ 315	133	$ 1.6731	$ 223	-	$ -	$ -	$ 223
June	238	$ 2.6625	$ 633	292	$ 1.6731	$ 488	-	$ -	$ -	$ 488
July	218	$ 2.6625	$ 581	293	$ 1.6731	$ 491	-	$ -	$ -	$ 491
August	202	$ 2.6625	$ 537	274	$ 1.6731	$ 459	-	$ -	$ -	$ 459
September	133	$ 2.6625	$ 354	261	$ 1.6731	$ 436	-	$ -	$ -	$ 436
October	97	$ 2.6625	$ 259	103	$ 1.6731	$ 172	-	$ -	$ -	$ 172
November	14	$ 2.6625	$ 37	15	$ 1.6731	$ 26	-	$ -	$ -	$ 26
December	13	$ 2.6625	$ 36	13	$ 1.6731	$ 23	-	$ -	$ -	$ 23
Total	1,104	$ 2.66	$ 2,940	1,457	$ 1.67	$ 2,438	-	$ -	$ -	$ 2,438

Add Extra Host Here (II)	Network			Line Connection			Transformation Connection			Total Connection
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Total	Network			Line Connection			Transformation Connection			Total Connection
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	150,258	$ 3.7099	$ 557,441	155,732	$ 0.9401	$ 146,398	123,560	$ 2.2500	$ 278,010	$ 424,408
February	140,263	$ 3.7099	$ 520,363	144,871	$ 0.9401	$ 136,189	114,429	$ 2.2500	$ 257,465	$ 393,654
March	131,372	$ 3.7098	$ 487,365	138,083	$ 0.9401	$ 129,814	105,599	$ 2.2500	$ 237,598	$ 367,412
April	130,097	$ 3.7098	$ 482,635	134,114	$ 0.9401	$ 126,084	102,221	$ 2.2500	$ 229,997	$ 356,081
May	175,974	$ 3.7093	$ 652,741	180,339	$ 0.9405	$ 169,616	140,320	$ 2.2500	$ 315,720	$ 485,336
June	165,173	$ 3.7085	$ 612,541	209,149	$ 0.9410	$ 196,814	152,964	$ 2.2500	$ 344,169	$ 540,983
July	195,469	$ 3.8287	$ 748,393	199,164	$ 0.9611	$ 191,407	156,627	$ 2.3000	$ 360,242	$ 551,649
August	187,452	$ 3.8287	$ 717,705	188,817	$ 0.9610	$ 181,460	147,017	$ 2.3000	$ 338,139	$ 519,599
September	189,745	$ 3.8292	$ 726,568	192,862	$ 0.9610	$ 185,333	149,907	$ 2.3000	$ 344,786	$ 530,119
October	145,056	$ 3.8292	$ 555,451	149,380	$ 0.9605	$ 143,478	117,382	$ 2.3000	$ 269,979	$ 413,456
November	142,760	$ 3.8299	$ 546,754	154,271	$ 0.9601	$ 148,111	115,310	$ 2.3000	$ 265,213	$ 413,324
December	135,282	$ 3.8299	$ 518,116	147,246	$ 0.9601	$ 141,366	107,017	$ 2.3000	$ 246,139	$ 387,505
Total	1,888,900	$ 3.77	$ 7,126,074	1,994,028	$ 0.95	$ 1,896,070	1,532,353	$ 2.28	$ 3,487,457	$ 5,383,528

Low Voltage Switchgear Credit (if applicable)	$ -
Total including deduction for Low Voltage Switchgear Credit	$ 5,383,528

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2020 Filers

The purpose of this sheet is to calculate the expected billing when forecasted 2019 Uniform Transmission Rates are applied against historical 2018 transmission units.

IESO	Network			Line Connection			Transformation Connection			Total Connection
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	150,244	$ 3.8300	$ 575,435	155,718	$ 0.9600	$ 149,489	123,560	$ 2.3000	$ 284,188	$ 433,677
February	140,250	$ 3.8300	$ 537,158	144,858	$ 0.9600	$ 139,064	114,429	$ 2.3000	$ 263,187	$ 402,250
March	131,349	$ 3.8300	$ 503,067	138,060	$ 0.9600	$ 132,538	105,599	$ 2.3000	$ 242,878	$ 375,415
April	130,075	$ 3.8300	$ 498,187	134,091	$ 0.9600	$ 128,727	102,221	$ 2.3000	$ 235,108	$ 363,836
May	175,856	$ 3.8300	$ 673,528	180,206	$ 0.9600	$ 172,998	140,320	$ 2.3000	$ 322,736	$ 495,734
June	164,935	$ 3.8300	$ 631,701	208,857	$ 0.9600	$ 200,503	152,964	$ 2.3000	$ 351,817	$ 552,320
July	195,251	$ 3.8300	$ 747,811	198,871	$ 0.9600	$ 190,916	156,627	$ 2.3000	$ 360,242	$ 551,158
August	187,250	$ 3.8300	$ 717,168	188,543	$ 0.9600	$ 181,001	147,017	$ 2.3000	$ 338,139	$ 519,140
September	189,612	$ 3.8300	$ 726,214	192,601	$ 0.9600	$ 184,897	149,907	$ 2.3000	$ 344,786	$ 529,683
October	144,959	$ 3.8300	$ 555,193	149,277	$ 0.9600	$ 143,306	117,382	$ 2.3000	$ 269,979	$ 413,285
November	142,746	$ 3.8300	$ 546,717	154,256	$ 0.9600	$ 148,086	115,310	$ 2.3000	$ 265,213	$ 413,299
December	135,269	$ 3.8300	$ 518,080	147,233	$ 0.9600	$ 141,344	107,017	$ 2.3000	$ 246,139	$ 387,483
Total	1,887,796	$ 3.83	$ 7,230,259	1,992,571	$ 0.96	$ 1,912,868	1,532,353	$ 2.30	$ 3,524,412	$ 5,437,280

Hydro One	Network			Line Connection			Transformation Connection			Total Connection
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ 3.2915	$ -	-	$ 0.7877	$ -	-	$ 1.9755	$ -	$ -
February	-	$ 3.2915	$ -	-	$ 0.7877	$ -	-	$ 1.9755	$ -	$ -
March	-	$ 3.2915	$ -	-	$ 0.7877	$ -	-	$ 1.9755	$ -	$ -
April	-	$ 3.2915	$ -	-	$ 0.7877	$ -	-	$ 1.9755	$ -	$ -
May	-	$ 3.2915	$ -	-	$ 0.7877	$ -	-	$ 1.9755	$ -	$ -
June	-	$ 3.2915	$ -	-	$ 0.7877	$ -	-	$ 1.9755	$ -	$ -
July	-	$ 3.2915	$ -	-	$ 0.7877	$ -	-	$ 1.9755	$ -	$ -
August	-	$ 3.2915	$ -	-	$ 0.7877	$ -	-	$ 1.9755	$ -	$ -
September	-	$ 3.2915	$ -	-	$ 0.7877	$ -	-	$ 1.9755	$ -	$ -
October	-	$ 3.2915	$ -	-	$ 0.7877	$ -	-	$ 1.9755	$ -	$ -
November	-	$ 3.2915	$ -	-	$ 0.7877	$ -	-	$ 1.9755	$ -	$ -
December	-	$ 3.2915	$ -	-	$ 0.7877	$ -	-	$ 1.9755	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Add Extra Host Here (I)	Network			Line Connection			Transformation Connection			Total Connection
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	14	$ 2.6625	$ 36	14	$ 1.6731	$ 23	-	$ -	$ -	$ 23
February	13	$ 2.6625	$ 35	13	$ 1.6731	$ 22	-	$ -	$ -	$ 22
March	23	$ 2.6625	$ 60	23	$ 1.6731	$ 38	-	$ -	$ -	$ 38
April	22	$ 2.6625	$ 57	23	$ 1.6731	$ 38	-	$ -	$ -	$ 38
May	118	$ 2.6625	$ 315	133	$ 1.6731	$ 223	-	$ -	$ -	$ 223
June	238	$ 2.6625	$ 633	292	$ 1.6731	$ 488	-	$ -	$ -	$ 488
July	218	$ 2.6625	$ 581	293	$ 1.6731	$ 491	-	$ -	$ -	$ 491
August	202	$ 2.6625	$ 537	274	$ 1.6731	$ 459	-	$ -	$ -	$ 459
September	133	$ 2.6625	$ 354	261	$ 1.6731	$ 436	-	$ -	$ -	$ 436
October	97	$ 2.6625	$ 259	103	$ 1.6731	$ 172	-	$ -	$ -	$ 172
November	14	$ 2.6625	$ 37	15	$ 1.6731	$ 26	-	$ -	$ -	$ 26
December	13	$ 2.6625	$ 36	13	$ 1.6731	$ 23	-	$ -	$ -	$ 23
Total	1,104	$ 2.66	$ 2,940	1,457	$ 1.67	$ 2,438	-	$ -	$ -	$ 2,438

Add Extra Host Here (II)	Network			Line Connection			Transformation Connection			Total Connection
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Total	Network			Line Connection			Transformation Connection			Total Connection
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	150,258	$ 3.83	$ 575,471	155,732	$ 0.96	$ 149,513	123,560	$ 2.30	$ 284,188	$ 433,701
February	140,263	$ 3.83	$ 537,193	144,871	$ 0.96	$ 139,086	114,429	$ 2.30	$ 263,187	$ 402,273
March	131,372	$ 3.83	$ 503,127	138,083	$ 0.96	$ 132,575	105,599	$ 2.30	$ 242,878	$ 375,453
April	130,097	$ 3.83	$ 498,244	134,114	$ 0.96	$ 128,766	102,221	$ 2.30	$ 235,108	$ 363,874
May	175,974	$ 3.83	$ 673,844	180,339	$ 0.96	$ 173,221	140,320	$ 2.30	$ 322,736	$ 495,957
June	165,173	$ 3.83	$ 632,334	209,149	$ 0.96	$ 200,991	152,964	$ 2.30	$ 351,817	$ 552,808
July	195,469	$ 3.83	$ 748,393	199,164	$ 0.96	$ 191,407	156,627	$ 2.30	$ 360,242	$ 551,649
August	187,452	$ 3.83	$ 717,705	188,817	$ 0.96	$ 181,460	147,017	$ 2.30	$ 338,139	$ 519,599
September	189,745	$ 3.83	$ 726,568	192,862	$ 0.96	$ 185,333	149,907	$ 2.30	$ 344,786	$ 530,119
October	145,056	$ 3.83	$ 555,451	149,380	$ 0.96	$ 143,478	117,382	$ 2.30	$ 269,979	$ 413,456
November	142,760	$ 3.83	$ 546,754	154,271	$ 0.96	$ 148,111	115,310	$ 2.30	$ 265,213	$ 413,324
December	135,282	$ 3.83	$ 518,116	147,246	$ 0.96	$ 141,366	107,017	$ 2.30	$ 246,139	$ 387,505
Total	1,888,900	$ 3.83	$ 7,233,199	1,994,028	$ 0.96	$ 1,915,306	1,532,353	$ 2.30	$ 3,524,412	$ 5,439,718

Low Voltage Switchgear Credit (if applicable)	$ -
Total including deduction for Low Voltage Switchgear Credit	$ 5,439,718

Incentive Rate-setting Mechanism Rate Generator for 2020 Filers

The purpose of this table is to re-align the current RTS Network Rates to recover current wholesale network costs.

Rate Class	Rate Description	Unit	Current RTSR-Network	Loss Adjusted Billed kWh	Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Adjusted RTSR Network
Residential Service Classification	Retail Transmission Rate - Network Service Rate	$/kWh	0.0079	310,952,460	0	2,456,524	35.5%	2,529,380	0.0081
General Service Less Than 50 kW Service Classification	Retail Transmission Rate - Network Service Rate	$/kWh	0.0070	97,759,903	0	684,319	9.9%	704,615	0.0072
General Service 50 To 4,999 kW Service Classification	Retail Transmission Rate - Network Service Rate	$/kW	2.4118		1,447,503	3,491,088	50.4%	3,594,626	2.4833
Embedded Distributor Service Classification	Retail Transmission Rate - Network Service Rate	$/kW	2.4118		95,219	229,649	3.3%	236,460	2.4833
Sentinel Lighting Service Classification	Retail Transmission Rate - Network Service Rate	$/kW	2.2521		520	1,171	0.0%	1,206	2.3189
Street Lighting Service Classification	Retail Transmission Rate - Network Service Rate	$/kW	2.3204		22,227	51,576	0.7%	53,105	2.3892
Unmetered Scattered Load Service Classification	Retail Transmission Rate - Network Service Rate	$/kWh	0.0042	1,545,347	0	6,490	0.1%	6,683	0.0043

The purpose of this table is to re-align the current RTS Connection Rates to recover current wholesale connection costs.

Rate Class	Rate Description	Unit	Current RTSR-Connection	Loss Adjusted Billed kWh	Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Adjusted RTSR-Connection
Residential Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0061	310,952,460	0	1,896,810	35.8%	1,929,665	0.0062
General Service Less Than 50 kW Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0054	97,759,903	0	527,903	10.0%	537,047	0.0055
General Service 50 To 4,999 kW Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.8282		1,447,503	2,646,325	50.0%	2,692,163	1.8599
Embedded Distributor Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.8282		95,219	174,079	3.3%	177,095	1.8599
Sentinel Lighting Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.7075		520	888	0.0%	903	1.7371
Street Lighting Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.6878		22,227	37,515	0.7%	38,165	1.7170
Unmetered Scattered Load Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0054	1,545,347	0	8,345	0.2%	8,489	0.0055

The purpose of this table is to update the re-aligned RTS Network Rates to recover future wholesale network costs.

Rate Class	Rate Description	Unit	Adjusted RTSR-Network	Loss Adjusted Billed kWh	Billed kW	Billed Amount	Billed Amount %	Forecast Wholesale Billing	Proposed RTSR-Network
Residential Service Classification	Retail Transmission Rate - Network Service Rate	$/kWh	0.0081	310,952,460	0	2,529,380	35.5%	2,567,403	**0.0083**
General Service Less Than 50 kW Service Classification	Retail Transmission Rate - Network Service Rate	$/kWh	0.0072	97,759,903	0	704,615	9.9%	715,207	**0.0073**
General Service 50 To 4,999 kW Service Classification	Retail Transmission Rate - Network Service Rate	$/kW	2.4833		1,447,503	3,594,626	50.4%	3,648,663	**2.5207**
Embedded Distributor Service Classification	Retail Transmission Rate - Network Service Rate	$/kW	2.4833		95,219	236,460	3.3%	240,015	**2.5207**
Sentinel Lighting Service Classification	Retail Transmission Rate - Network Service Rate	$/kW	2.3189		520	1,206	0.0%	1,224	**2.3537**
Street Lighting Service Classification	Retail Transmission Rate - Network Service Rate	$/kW	2.3892		22,227	53,105	0.7%	53,903	**2.4251**
Unmetered Scattered Load Service Classification	Retail Transmission Rate - Network Service Rate	$/kWh	0.0043	1,545,347	0	6,683	0.1%	6,783	**0.0044**

The purpose of this table is to update the re-aligned RTS Connection Rates to recover future wholesale connection costs.

Rate Class	Rate Description	Unit	Adjusted RTSR-Connection	Loss Adjusted Billed kWh	Billed kW	Billed Amount	Billed Amount %	Forecast Wholesale Billing	Proposed RTSR-Connection
Residential Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0062	310,952,460	0	1,929,665	35.8%	1,949,806	**0.0063**
General Service Less Than 50 kW Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0055	97,759,903	0	537,047	10.0%	542,653	**0.0056**
General Service 50 To 4,999 kW Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.8599		1,447,503	2,692,163	50.0%	2,720,262	**1.8793**
Embedded Distributor Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.8599		95,219	177,095	3.3%	178,943	**1.8793**
Sentinel Lighting Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.7371		520	903	0.0%	913	**1.7552**
Street Lighting Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.7170		22,227	38,165	0.7%	38,563	**1.7350**
Unmetered Scattered Load Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0055	1,545,347	0	8,489	0.2%	8,578	**0.0056**

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2020 Filers

If applicable, please enter any adjustments related to the revenue to cost ratio model into columns C and E. The Price Escalator and Stretch Factor have been set at the 2018 values and will be updated by OEB staff at a later date.

Price Escalator	**1.20%**	**Productivity Factor**	**0.00%**
Choose Stretch Factor Group	III	**Price Cap Index**	**0.90%**
Associated Stretch Factor Value	**0.30%**		

Rate Class	Current MFC	MFC Adjustment from R/C Model	Current Volumetric Charge	DVR Adjustment from R/C Model	Price Cap Index to be Applied to MFC and DVR	Proposed MFC	Proposed Volumetric Charge
RESIDENTIAL SERVICE CLASSIFICATION	23.5				0.90%	23.71	0.0000
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	30.77		0.0081		0.90%	31.05	0.0082
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	236.93		2.8643		0.90%	239.06	2.8901
EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION	362.56		2.0121		0.90%	365.82	2.0302
SENTINEL LIGHTING SERVICE CLASSIFICATION	4.24		20.3		0.90%	4.28	20.4827
STREET LIGHTING SERVICE CLASSIFICATION	1.45		6.0789		0.90%	1.46	6.1336
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	13.12		0.0091		0.90%	13.24	0.0092
STANDBY POWER SERVICE CLASSIFICATION	0		1.7389		0.90%	0.00	1.7546
MICROFIT SERVICE CLASSIFICATION	5.4					5.4	

If applicable, Wheeling Service Rate will be adjusted for PCI on Sheet 19.

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2020 Filers

Update the following rates if an OEB Decision has been issued at the time of completing this application

Regulatory Charges

Effective Date of Regulatory Charges		January 1, 2019	January 1, 2020
Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$/kWh	0.25	0.25

Time-of-Use RPP Prices

As of		May 1, 2019
Off-Peak	$/kWh	0.0650
Mid-Peak	$/kWh	0.0940
On-Peak	$/kWh	0.1340

Smart Meter Entity Charge (SME)

Smart Meter Entity Charge (SME)	$	0.57

Distribution Rate Protection (DRP) Amount (Applicable to LDCs under the Distribution Rate Protection program):	$	36.86

Miscellaneous Service Charges

Wireline Pole Attachment Charge	Unit	Current charge	Inflation factor *	Proposed charge ** / ***
Specific charge for access to the power poles - per pole/year	$	43.63	1.20%	44.15

Retail Service Charges		Current charge	Inflation factor*	Proposed charge ***
One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00	1.20%	101.20
Monthly fixed charge, per retailer	$	40.00	1.20%	40.48
Monthly variable charge, per customer, per retailer	$/cust.	1.00	1.20%	1.01
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.60	1.20%	0.61
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.60)	1.20%	(0.61)
Service Transaction Requests (STR)				-
Request fee, per request, applied to the requesting party	$	0.50	1.20%	0.51
Processing fee, per request, applied to the requesting party	$	1.00	1.20%	1.01
Electronic Business Transaction (EBT) system, applied to the requesting party				
up to twice a year		no charge		no charge
more than twice a year, per request (plus incremental delivery costs)	$	4.00	1.20%	4.05
Notice of switch letter charge, per letter	$	2.00	1.20%	2.02

* inflation factor subject to change pending OEB approved inflation rate effective in 2020

** applicable only to LDCs in which the province-wide pole attachment charge applies

*** subject to change pending OEB order on miscellaneous service charges

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2020 Filers

In the Green Cells below, enter all proposed rate riders/rates. Please note that the following rates/charges are to be entered in the Final Tariff Schedule tab: Monthly Service Charge, Distribution Volumetric Rate and Retail Transmission Rates.
In column A, select the rate rider descriptions from the drop-down list in the blue cells. If the rate description cannot be found, enter the rate rider descriptions in the green cells. The rate rider description must begin with "Rate Rider for".
In column B, choose the associated unit from the drop-down menu.
In column C, enter the rate. All rate riders with a "$" unit should be rounded to 2 decimal places and all others rounded to 4 decimal places.
In column E, enter the expiry date (e.g. April 30, 2020) or description of the expiry date in text (e.g. the effective date of the next cost of service-based rate order).
In column G, a sub-total (A or B) should already be assigned to the rate rider unless the rate description was entered into a green cell in column A. In these particular cases, from the dropdown list in column G, choose the appropriate sub-total (A or B) . Sub-Total A refers to rates/rate riders that Not considered as pass through costs (eg: LRAMVA and ICM/ACM rate riders). Sub-Total B refers to rates/rate riders that are considered pass through costs.

RESIDENTIAL SERVICE CLASSIFICATION	UNIT	RATE		DATE (EG: April 30, 2020)	SUB-TOTAL
Rate Rider for Recovery of Incremental Capital	$	1.75	- effective until		A
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	UNIT	RATE		DATE (EG: April 30, 2020)	SUB-TOTAL
Rate Rider for Recovery of Incremental Capital	$	3.98	- effective until		A
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		

GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	UNIT	RATE		DATE (EG: April 30, 2020)	SUB-TOTAL
Rate Rider for Recovery of Incremental Capital	$	70.44	- effective until		A
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		

EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION	UNIT	RATE		DATE (EG: April 30, 2020)	SUB-TOTAL
Rate Rider for Recovery of Incremental Capital	$	1,215.36	- effective until		A
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		

SENTINEL LIGHTING SERVICE CLASSIFICATION	UNIT	RATE		DATE (EG: April 30, 2020)	SUB-TOTAL
Rate Rider for Recovery of Incremental Capital	$	0.45	- effective until		A
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		

STREET LIGHTING SERVICE CLASSIFICATION	UNIT	RATE		DATE (EG: April 30, 2020)	SUB-TOTAL
Rate Rider for Recovery of Incremental Capital	$	0.25	- effective until		A
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	UNIT	RATE		DATE (EG: April 30, 2020)	SUB-TOTAL
Rate Rider for Recovery of Incremental Capital	$	1.18	- effective until		A
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		

Brantford Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2020
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2019-0022

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	23.71
Rate Rider for Recovery of Incremental Capital - effective until	$	1.75
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Retail Transmission Rate - Network Service Rate	$/kWh	0.0083
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0063

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Brantford Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2020

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2019-0022

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to a non residential account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	31.05
Rate Rider for Recovery of Incremental Capital - effective until	$	3.98
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Distribution Volumetric Rate	$/kWh	0.0082
Retail Transmission Rate - Network Service Rate	$/kWh	0.0073
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0056

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Brantford Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2020
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2019-0022

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

The rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

The rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	239.06
Rate Rider for Recovery of Incremental Capital - effective until	$	70.44
Distribution Volumetric Rate	$/kW	2.8901
Retail Transmission Rate - Network Service Rate	$/kW	2.5207
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.8793

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Brantford Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2020
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2019-0022

EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION

This classification applies to an electricity distributor licensed by the Ontario Energy Board that is provided electricity by means of this distributor's facilities. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Approved on an Interim Basis

Service Charge	$	365.82
Rate Rider for Recovery of Incremental Capital - effective until	$	1,215.36
Distribution Volumetric Rate	$/kW	2.0302
Retail Transmission Rate - Network Service Rate	$/kW	2.5207
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.8793

Brantford Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2020

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2019-0022

microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.40

Brantford Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2020
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EB-2019-0022

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	4.28
Rate Rider for Recovery of Incremental Capital - effective until	$	0.45
Distribution Volumetric Rate	$/kW	20.4827
Retail Transmission Rate - Network Service Rate	$/kW	2.3537
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.7552

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Brantford Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2020
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EB-2019-0022

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photocells. The consumption for these customers will be based on the calculated load times the required lighting times established in the approved Ontario Energy Board street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	1.46
Rate Rider for Recovery of Incremental Capital - effective until	$	0.25
Distribution Volumetric Rate	$/kW	6.1336
Retail Transmission Rate - Network Service Rate	$/kW	2.4251
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.7350

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Brantford Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2020

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EB-2019-0022

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone boots, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information/ documentation with regard to electrical demand/consumption of the proposed unmetered load. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	13.24
Rate Rider for Recovery of Incremental Capital - effective until	$	1.18
Distribution Volumetric Rate	$/kWh	0.0092
Retail Transmission Rate - Network Service Rate	$/kWh	0.0044
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0056

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Brantford Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2020
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EB-2019-0022

STANDBY POWER SERVICE CLASSIFICATION

This classification refers to an account that has Load Displacement Generation and requires the distributor to provide back-up service. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

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MONTHLY RATES AND CHARGES - Delivery Component - Approved on an Interim Basis

Standby Charge - for a month where standby power is not provided. The charge is applied to the contracted amount (e.g. nameplate rating of the generation facility).	$/kW	1.7546

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for Transformer Losses - applied to measured demand & energy	%	(1.00)

Brantford Power Inc.
TARIFF OF RATES AND CHARGES
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EB-2019-0022

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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Customer Administration		
Easement letter	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned cheque (plus bank charges)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late payment - per month	%	1.50
Late payment - per annum	%	19.56
Collection of account charge - no disconnection	$	30.00
Disconnect/reconnect at meter - during regular hours	$	65.00
Disconnect/reconnect at meter - after regular hours	$	185.00
Disconnect/reconnect at pole - during regular hours	$	185.00
Disconnect/reconnect at pole - after regular hours	$	415.00
Install/remove load control device - during regular hours	$	65.00
Install/remove load control device - after regular hours	$	185.00
Other		
Temporary service install & remove - overhead - no transformer	$	500.00
Temporary service - install & remove - underground - no transformer	$	300.00
Specific charge for access to the power poles - per pole/year (with the exception of wireless attachments)	$	44.15
Meter removal without authorization	$	60.00

Brantford Power Inc.
TARIFF OF RATES AND CHARGES
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EB-2019-0022

RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

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Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	101.20
Monthly fixed charge, per retailer	$	40.48
Monthly variable charge, per customer, per retailer	$/cust.	1.01
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.61
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.61)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.51
Processing fee, per request, applied to the requesting party	$	1.01
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
up to twice a year	$	no charge
more than twice a year, per request (plus incremental delivery costs)	$	4.05

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.032
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0218

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2020 Filers

The bill comparisons below must be provided for typical customers and consumption levels. Bill impacts must be provided for residential customers consuming 750 kWh per month and general service customers consuming 2,000 kWh per month and having a monthly demand of less than 50 kW. Include bill comparisons for Non-RPP (retailer) as well. **To assess the combined effects of the shift to fixed rates and other bill impacts associated with changes in the cost of distribution service, applicants are to include a total bill impact for a residential customer at the distributor's 10th consumption percentile (In other words, 10% of a distributor's residential customers consume at or less than this level of consumption on a monthly basis). Refer to section 3.2.3 of the Chapter 3 Filing Requirements For Electricity Distribution Rate Applications.**

For certain classes where one or more customers have unique consumption and demand patterns and which may be significantly impacted by the proposed rate changes, the distributor must show a typical comparison, and provide an explanation.

Note:
1. For those classes that are not eligible for the RPP price, the weighted average price including Class B GA through end of May 2018 of $0.1117/kWh (IESO's Monthly Market Report for May 2018, page 22) has been used to represent the cost of power. For those classes on a retailer contract, applicants should enter the contract price (plus GA) for a more accurate estimate. Changes to the cost of power can be made directly on the bill impact table for the specific class.
2. Please enter the applicable billing determinant (e.g. number of connections or devices) to be applied to the monthly service charge for unmetered rate classes in column N. If the monthly service charge is applied on a per customer basis, enter the number "1". Distributors should provide the number of connections or devices reflective of a typical customer in each class.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Table 1

RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	**Units**	**RPP? Non-RPP Retailer? Non-RPP Other?**	**Current Loss Factor** (eg: 1.0351)	**Proposed Loss Factor**	**Consumption (kWh)**	**Demand kW (if applicable)**	**RTSR Demand or Demand-Interval?**	**Billing Determinant Applied to Fixed Charge for Unmetered Classes (e.g. # of devices/connections).**
RESIDENTIAL SERVICE CLASSIFICATION	kWh	RPP	1.032	1.032	750		CONSUMPTION	
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	RPP	1.032	1.032	2,000		CONSUMPTION	
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.032	1.032	100,000	250	DEMAND	
EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.032	1.032	2,000,000	12,000	DEMAND	
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.032	1.032	55	1	DEMAND	1
STREET LIGHTING SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.032	1.032	622,000	1,900	DEMAND	5,849
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	Non-RPP (Other)	1.032	1.032	280		CONSUMPTION	1
STANDBY POWER SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.032	1.032	-			
Add additional scenarios if required			1.032	1.032				
Add additional scenarios if required			1.032	1.032				
Add additional scenarios if required			1.032	1.032				
Add additional scenarios if required			1.032	1.032				
Add additional scenarios if required			1.032	1.032				
Add additional scenarios if required			1.032	1.032				
Add additional scenarios if required			1.032	1.032				
Add additional scenarios if required			1.032	1.032				
Add additional scenarios if required			1.032	1.032				
Add additional scenarios if required			1.032	1.032				
Add additional scenarios if required			1.032	1.032				
Add additional scenarios if required			1.032	1.032				

Table 2

RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	Units	Sub-Total						Total	
		A		B		C		Total Bill	
		$	%	$	%	$	%	$	%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ 1.59	6.6%	$ 3.24	13.1%	$ 3.70	10.4%	$ 3.88	3.7%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kWh	$ 2.66	5.5%	$ 7.06	14.1%	$ 8.09	10.7%	$ 8.50	3.3%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 59.87	6.2%	$ 558.02	117.7%	$ 598.02	39.0%	$ 675.76	4.5%
EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 1,435.82	5.9%	$ (1,870.18)	-6.7%	$ 49.82	0.1%	$ 56.30	0.0%
SENTINEL LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 0.67	2.7%	$ 1.55	6.5%	$ 1.70	6.1%	$ 1.92	4.9%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 1,624.67	8.1%	$ 4,831.31	28.7%	$ 5,119.92	20.9%	$ 5,785.51	5.2%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - Non-RPP (Other)	kWh	$ 1.33	8.5%	$ 2.00	12.5%	$ 2.12	11.3%	$ 2.39	4.2%
STANDBY POWER SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ -	0.0%	$ -	0.0%	$ -	0.0%	$ -	0.0%

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	750 kWh
Demand	- kW
Current Loss Factor	1.0320
Proposed/Approved Loss Factor	1.0320

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 23.50	1	$ 23.50	$ 23.71	1	$ 23.71	$ 0.21	0.89%
Distribution Volumetric Rate	$ -	750	$ -	$ -	750	$ -	$ -	
Fixed Rate Riders	$ -	1	$ -	$ 1.75	1	$ 1.75	$ 1.75	
Volumetric Rate Riders	$ 0.0005	750	$ 0.38	$ -	750	$ -	$ (0.38)	-100.00%
Sub-Total A (excluding pass through)			**$ 23.88**			**$ 25.46**	**$ 1.59**	**6.64%**
Line Losses on Cost of Power	$ 0.0824	24	$ 1.98	$ 0.0824	24	$ 1.98	$ -	0.00%
Total Deferral/Variance Account Rate Riders	-$ 0.0020	750	$ (1.50)	$ -	750	$ -	$ 1.50	-100.00%
CBR Class B Rate Riders	-$ 0.0002	750	$ (0.15)	$ -	750	$ -	$ 0.15	-100.00%
GA Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
Low Voltage Service Charge	$ -	750	$ -		750	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ 0.57	1	$ 0.57	$ 0.57	1	$ 0.57	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		750	$ -	$ -	750	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 24.77**			**$ 28.01**	**$ 3.24**	**13.06%**
RTSR - Network	$ 0.0079	774	$ 6.11	$ 0.0083	774	$ 6.42	$ 0.31	5.06%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0061	774	$ 4.72	$ 0.0063	774	$ 4.88	$ 0.15	3.28%
Sub-Total C - Delivery (including Sub-Total B)			**$ 35.61**			**$ 39.31**	**$ 3.70**	**10.39%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	774	$ 2.63	$ 0.0034	774	$ 2.63	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	774	$ 0.39	$ 0.0005	774	$ 0.39	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0650	488	$ 31.69	$ 0.0650	488	$ 31.69	$ -	0.00%
TOU - Mid Peak	$ 0.0940	128	$ 11.99	$ 0.0940	128	$ 11.99	$ -	0.00%
TOU - On Peak	$ 0.1340	135	$ 18.09	$ 0.1340	135	$ 18.09	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 100.64**			**$ 104.34**	**$ 3.70**	**3.68%**
HST	13%		$ 13.08	13%		$ 13.56	$ 0.48	3.68%
8% Rebate	8%		$ (8.05)	8%		$ (8.35)	$ (0.30)	
Total Bill on TOU			**$ 105.67**			**$ 109.55**	**$ 3.88**	**3.68%**

In the manager's summary, discuss the reasoi

Customer Class:	GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	2,000 kWh
Demand	- kW
Current Loss Factor	1.0320
Proposed/Approved Loss Factor	1.0320

	Current OEB-Approved			Proposed			Impact		
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	
Monthly Service Charge	$ 30.77	1	$ 30.77	$ 31.05	1	$ 31.05	$ 0.28	0.91%	
Distribution Volumetric Rate	$ 0.0081	2000	$ 16.20	$ 0.0082	2000	$ 16.40	$ 0.20	1.23%	
Fixed Rate Riders	$ -	1	$ -	$ 3.98	1	$ 3.98	$ 3.98		
Volumetric Rate Riders	$ 0.0009	2000	$ 1.80	$ -	2000	$ -	$ (1.80)	-100.00%	
Sub-Total A (excluding pass through)			**$ 48.77**			**$ 51.43**	**$ 2.66**	**5.45%**	
Line Losses on Cost of Power	$ 0.0824	64	$ 5.27	$ 0.0824	64	$ 5.27	$ -	0.00%	
Total Deferral/Variance Account Rate Riders	-$ 0.0020	2,000	$ (4.00)	$ -	2,000	$ -	$ 4.00	-100.00%	
CBR Class B Rate Riders	-$ 0.0002	2,000	$ (0.40)	$ -	2,000	$ -	$ 0.40	-100.00%	
GA Rate Riders	$ -	2,000	$ -	$ -	2,000	$ -	$ -		
Low Voltage Service Charge	$ -	2,000	$ -		2,000	$ -	$ -		
Smart Meter Entity Charge (if applicable)	$ 0.57	1	$ 0.57	$ 0.57	1	$ 0.57	$ -	0.00%	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Volumetric Rate Riders		2,000	$ -	$ -	2,000	$ -	$ -		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 50.21**			**$ 57.27**	**$ 7.06**	**14.06%**	
RTSR - Network	$ 0.0070	2,064	$ 14.45	$ 0.0073	2,064	$ 15.07	$ 0.62	4.29%	In the manager's summary, discuss the reaso
RTSR - Connection and/or Line and Transformation Connection	$ 0.0054	2,064	$ 11.15	$ 0.0056	2,064	$ 11.56	$ 0.41	3.70%	
Sub-Total C - Delivery (including Sub-Total B)			**$ 75.80**			**$ 83.90**	**$ 8.09**	**10.67%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	2,064	$ 7.02	$ 0.0034	2,064	$ 7.02	$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	2,064	$ 1.03	$ 0.0005	2,064	$ 1.03	$ -	0.00%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
TOU - Off Peak	$ 0.0650	1,300	$ 84.50	$ 0.0650	1,300	$ 84.50	$ -	0.00%	
TOU - Mid Peak	$ 0.0940	340	$ 31.96	$ 0.0940	340	$ 31.96	$ -	0.00%	
TOU - On Peak	$ 0.1340	360	$ 48.24	$ 0.1340	360	$ 48.24	$ -	0.00%	
Total Bill on TOU (before Taxes)			**$ 248.80**			**$ 256.90**	**$ 8.09**	**3.25%**	
HST	13%		$ 32.34	13%		$ 33.40	$ 1.05	3.25%	
8% Rebate	8%		$ (19.90)	8%		$ (20.55)	$ (0.65)		
Total Bill on TOU			**$ 261.24**			**$ 269.74**	**$ 8.50**	**3.25%**	

Customer Class:	GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Other)
Consumption	100,000 kWh
Demand	250 kW
Current Loss Factor	1.0320
Proposed/Approved Loss Factor	1.0320

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 236.93	1	$ 236.93	$ 239.06	1	$ 239.06	$ 2.13	0.90%
Distribution Volumetric Rate	$ 2.8643	250	$ 716.08	$ 2.8901	250	$ 722.53	$ 6.45	0.90%
Fixed Rate Riders	$ -	1	$ -	$ 70.44	1	$ 70.44	$ 70.44	
Volumetric Rate Riders	$ 0.0766	250	$ 19.15	$ -	250	$ -	$ (19.15)	-100.00%
Sub-Total A (excluding pass through)			**$ 972.16**			**$ 1,032.03**	**$ 59.87**	**6.16%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	-$ 0.7369	250	$ (184.23)	$ -	250	$ -	$ 184.23	-100.00%
CBR Class B Rate Riders	-$ 0.0557	250	$ (13.93)	$ -	250	$ -	$ 13.93	-100.00%
GA Rate Riders	-$ 0.0030	100,000	$ (300.00)	$ -	100,000	$ -	$ 300.00	-100.00%
Low Voltage Service Charge	$ -	250	$ -		250	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		250	$ -	$ -	250	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 474.01**			**$ 1,032.03**	**$ 558.02**	**117.72%**
RTSR - Network	$ 2.4118	250	$ 602.95	$ 2.5207	250	$ 630.18	$ 27.23	4.52%
RTSR - Connection and/or Line and Transformation Connection	$ 1.8282	250	$ 457.05	$ 1.8793	250	$ 469.83	$ 12.78	2.80%
Sub-Total C - Delivery (including Sub-Total B)			**$ 1,534.01**			**$ 2,132.03**	**$ 598.02**	**38.98%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	103,200	$ 350.88	$ 0.0034	103,200	$ 350.88	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	103,200	$ 51.60	$ 0.0005	103,200	$ 51.60	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1101	103,200	$ 11,362.32	$ 0.1101	103,200	$ 11,362.32	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price			**$ 13,299.06**			**$ 13,897.08**	**$ 598.02**	**4.50%**
HST	13%		$ 1,728.88	13%		$ 1,806.62	$ 77.74	4.50%
Total Bill on Average IESO Wholesale Market Price			**$ 15,027.93**			**$ 15,703.69**	**$ 675.76**	**4.50%**

In the manager's summary, discuss the reasor

Customer Class:	EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION	
RPP / Non-RPP:	Non-RPP (Other)	
Consumption	2,000,000	kWh
Demand	12,000	kW
Current Loss Factor	1.0320	
Proposed/Approved Loss Factor	1.0320	

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 362.56	1	$ 362.56	$ 365.82	1	$ 365.82	$ 3.26	0.90%
Distribution Volumetric Rate	$ 2.0121	12000	$ 24,145.20	$ 2.0302	12000	$ 24,362.40	$ 217.20	0.90%
Fixed Rate Riders	$ -	1	$ -	$ 1,215.36	1	$ 1,215.36	$ 1,215.36	
Volumetric Rate Riders	$ -	12000	$ -	$ -	12000	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 24,507.76**			**$ 25,943.58**	**$ 1,435.82**	**5.86%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ 0.2755	12,000	$ 3,306.00	$ -	12,000	$ -	$ (3,306.00)	-100.00%
CBR Class B Rate Riders	$ -	12,000	$ -	$ -	12,000	$ -	$ -	
GA Rate Riders	$ -	2,000,000	$ -	$ -	2,000,000	$ -	$ -	
Low Voltage Service Charge	$ -	12,000	$ -		12,000	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		12,000	$ -	$ -	12,000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 27,813.76**			**$ 25,943.58**	**$ (1,870.18)**	**-6.72%**
RTSR - Network	$ 2.4118	12,000	$ 28,941.60	$ 2.5207	12,000	$ 30,248.40	$ 1,306.80	4.52%
RTSR - Connection and/or Line and Transformation Connection	$ 1.8282	12,000	$ 21,938.40	$ 1.8793	12,000	$ 22,551.60	$ 613.20	2.80%
Sub-Total C - Delivery (including Sub-Total B)			**$ 78,693.76**			**$ 78,743.58**	**$ 49.82**	**0.06%**
Wholesale Market Service Charge (WMSC)		2,064,000	$ -		2,064,000	$ -	$ -	
Rural and Remote Rate Protection (RRRP)		2,064,000	$ -		2,064,000	$ -	$ -	
Standard Supply Service Charge		1	$ -		1	$ -	$ -	
Average IESO Wholesale Market Price	$ 0.1101	2,064,000	$ 227,246.40	$ 0.1101	2,064,000	$ 227,246.40	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price			**$ 305,940.16**			**$ 305,989.98**	**$ 49.82**	**0.02%**
HST	13%		$ 39,772.22	13%		$ 39,778.70	$ 6.48	0.02%
Total Bill on Average IESO Wholesale Market Price			**$ 345,712.38**			**$ 345,768.68**	**$ 56.30**	**0.02%**

In the manager's summary, discuss the reasor

Customer Class:	SENTINEL LIGHTING SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Other)
Consumption	55 kWh
Demand	1 kW
Current Loss Factor	1.0320
Proposed/Approved Loss Factor	1.0320

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 4.24	1	$ 4.24	$ 4.28	1	$ 4.28	$ 0.04	0.94%
Distribution Volumetric Rate	$ 20.3000	1	$ 20.30	$ 20.4827	1	$ 20.48	$ 0.18	0.90%
Fixed Rate Riders	$ -	1	$ -	$ 0.45	1	$ 0.45	$ 0.45	
Volumetric Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 24.54**			**$ 25.21**	**$ 0.67**	**2.74%**
Line Losses on Cost of Power	$ 0.1101	2	$ 0.19	$ 0.1101	2	$ 0.19	$ -	0.00%
Total Deferral/Variance Account Rate Riders	-$ 0.6492	1	$ (0.65)	$ -	1	$ -	$ 0.65	-100.00%
CBR Class B Rate Riders	-$ 0.0544	1	$ (0.05)	$ -	1	$ -	$ 0.05	-100.00%
GA Rate Riders	-$ 0.0031	55	$ (0.17)	$ -	55	$ -	$ 0.17	-100.00%
Low Voltage Service Charge	$ -	1	$ -		1	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		1	$ -	$ -	1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 23.86**			**$ 25.41**	**$ 1.55**	**6.48%**
RTSR - Network	$ 2.2521	1	$ 2.25	$ 2.3537	1	$ 2.35	$ 0.10	4.51% *In the manager's summary, discuss the reasor*
RTSR - Connection and/or Line and Transformation Connection	$ 1.7075	1	$ 1.71	$ 1.7552	1	$ 1.76	$ 0.05	2.79%
Sub-Total C - Delivery (including Sub-Total B)			**$ 27.82**			**$ 29.52**	**$ 1.70**	**6.10%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	57	$ 0.19	$ 0.0034	57	$ 0.19	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	57	$ 0.03	$ 0.0005	57	$ 0.03	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1101	55	$ 6.06	$ 0.1101	55	$ 6.06	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price			**$ 34.35**			**$ 36.04**	**$ 1.70**	**4.94%**
HST	13%		$ 4.46	13%		$ 4.69	$ 0.22	4.94%
Total Bill on Average IESO Wholesale Market Price			**$ 38.81**			**$ 40.73**	**$ 1.92**	**4.94%**

Customer Class:	STREET LIGHTING SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Other)
Consumption	622,000 kWh
Demand	1,900 kW
Current Loss Factor	1.0320
Proposed/Approved Loss Factor	1.0320

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	$ 1.45	5849	$ 8,481.05	$ 1.46	5849	$ 8,539.54	$ 58.49	0.69%
Distribution Volumetric Rate	$ 6.0789	1900	$ 11,549.91	$ 6.1336	1900	$ 11,653.84	$ 103.93	0.90%
Fixed Rate Riders	$ -	5849	$ -	$ 0.25	5849	$ 1,462.25	$ 1,462.25	
Volumetric Rate Riders	$ -	1900	$ -	$ -	1900	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 20,030.96**			**$ 21,655.63**	**$ 1,624.67**	**8.11%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	-$ 0.6505	1,900	$ (1,235.95)	$ -	1,900	$ -	$ 1,235.95	-100.00%
CBR Class B Rate Riders	-$ 0.0551	1,900	$ (104.69)	$ -	1,900	$ -	$ 104.69	-100.00%
GA Rate Riders	-$ 0.0030	622,000	$ (1,866.00)	$ -	622,000	$ -	$ 1,866.00	-100.00%
Low Voltage Service Charge	$ -	1,900	$ -		1,900	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		1,900	$ -	$ -	1,900	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 16,824.32**			**$ 21,655.63**	**$ 4,831.31**	**28.72%**
RTSR - Network	$ 2.3204	1,900	$ 4,408.76	$ 2.4251	1,900	$ 4,607.69	$ 198.93	4.51%
RTSR - Connection and/or Line and Transformation Connection	$ 1.6878	1,900	$ 3,206.82	$ 1.7350	1,900	$ 3,296.50	$ 89.68	2.80%
Sub-Total C - Delivery (including Sub-Total B)			**$ 24,439.90**			**$ 29,559.82**	**$ 5,119.92**	**20.95%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	641,904	$ 2,182.47	$ 0.0034	641,904	$ 2,182.47	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	641,904	$ 320.95	$ 0.0005	641,904	$ 320.95	$ -	0.00%
Standard Supply Service Charge	$ 0.25	5849	$ 1,462.25	$ 0.25	5849	$ 1,462.25	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1101	641,904	$ 70,673.63	$ 0.1101	641,904	$ 70,673.63	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price			**$ 99,079.21**			**$ 104,199.13**	**$ 5,119.92**	**5.17%**
HST	13%		$ 12,880.30	13%		$ 13,545.89	$ 665.59	5.17%
Total Bill on Average IESO Wholesale Market Price			**$ 111,959.50**			**$ 117,745.01**	**$ 5,785.51**	**5.17%**

In the manager's summary, discuss the reaso

Customer Class:	UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Other)
Consumption	280 kWh
Demand	- kW
Current Loss Factor	1.0320
Proposed/Approved Loss Factor	1.0320

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 13.12	1	$ 13.12	$ 13.24	1	$ 13.24	$ 0.12	0.91%
Distribution Volumetric Rate	$ 0.0091	280	$ 2.55	$ 0.0092	280	$ 2.58	$ 0.03	1.10%
Fixed Rate Riders	$ -	1	$ -	$ 1.18	1	$ 1.18	$ 1.18	
Volumetric Rate Riders	$ -	280	$ -	$ -	280	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 15.67**			**$ 17.00**	**$ 1.33**	**8.48%**
Line Losses on Cost of Power	$ 0.1101	9	$ 0.99	$ 0.1101	9	$ 0.99	$ -	0.00%
Total Deferral/Variance Account Rate Riders	-$ 0.0022	280	$ (0.62)	$ -	280	$ -	$ 0.62	-100.00%
CBR Class B Rate Riders	-$ 0.0002	280	$ (0.06)	$ -	280	$ -	$ 0.06	-100.00%
GA Rate Riders	$ -	280	$ -	$ -	280	$ -	$ -	
Low Voltage Service Charge	$ -	280	$ -		280	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		280	$ -	$ -	280	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 15.98**			**$ 17.98**	**$ 2.00**	**12.51%**
RTSR - Network	$ 0.0042	289	$ 1.21	$ 0.0044	289	$ 1.27	$ 0.06	4.76%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0054	289	$ 1.56	$ 0.0056	289	$ 1.62	$ 0.06	3.70%
Sub-Total C - Delivery (including Sub-Total B)			**$ 18.76**			**$ 20.87**	**$ 2.12**	**11.28%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	289	$ 0.98	$ 0.0034	289	$ 0.98	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	289	$ 0.14	$ 0.0005	289	$ 0.14	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1101	280	$ 30.83	$ 0.1101	280	$ 30.83	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price			**$ 50.96**			**$ 53.08**	**$ 2.12**	**4.15%**
HST	13%		$ 6.62	13%		$ 6.90	$ 0.28	4.15%
Total Bill on Average IESO Wholesale Market Price			**$ 57.59**			**$ 59.98**	**$ 2.39**	**4.15%**

In the manager's summary, discuss the reasor

Customer Class:	STANDBY POWER SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Other)
Consumption	- kWh
Demand	- kW
Current Loss Factor	1.0320
Proposed/Approved Loss Factor	1.0320

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ -	1	$ -	$ -	1	$ -	$ -	
Distribution Volumetric Rate	$ 1.7389	0	$ -	$ 1.7546	0	$ -	$ -	
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ -	0	$ -	$ -	0	$ -	$ -	
Sub-Total A (excluding pass through)			**$ -**			**$ -**	**$ -**	
Line Losses on Cost of Power	$ 0.1101	-	$ -	$ 0.1101	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ -	-	$ -	$ -	-	$ -	$ -	
CBR Class B Rate Riders	$ -	-	$ -	$ -	-	$ -	$ -	
GA Rate Riders	$ -	-	$ -	$ -	-	$ -	$ -	
Low Voltage Service Charge	$ -	-	$ -		-	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		-	$ -	$ -	-	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ -**			**$ -**	**$ -**	
RTSR - Network	$ -	-	$ -	$ -	-	$ -	$ -	
RTSR - Connection and/or Line and Transformation Connection	$ -	-	$ -	$ -	-	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ -**			**$ -**	**$ -**	
Wholesale Market Service Charge (WMSC)		-	$ -		-	$ -	$ -	
Rural and Remote Rate Protection (RRRP)		-	$ -		-	$ -	$ -	
Standard Supply Service Charge		1	$ -		1	$ -	$ -	
Average IESO Wholesale Market Price	$ 0.1101	-	$ -	$ 0.1101	-	$ -	$ -	
Total Bill on Average IESO Wholesale Market Price			**$ -**			**$ -**	**$ -**	
HST	13%		$ -	13%		$ -	$ -	
Total Bill on Average IESO Wholesale Market Price			**$ -**			**$ -**	**$ -**	

IRM Attachment C:

Certification of Evidence

Certification of Evidence

I hereby certify that, to the best of my knowledge, the evidence filed in this Application is accurate, consistent and complete. BPI has robust processes and internal controls in place for the preparation, review, verification and oversight of account balances being proposed for disposition.

Certified by:

Original Signed By Brian D'Amboise

____

Date: August 12, 2019

Brian D'Amboise, CPA, CA
Chief Financial Officer and VP of
Corporate Services
Brantford Power Inc.
Box 308
84 Market Street
Brantford ON N3T 5N8
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IRM Attachment D:

Most Recent Tariff of Rates (2019)

Schedule A

To Decision and Rate Order

Tariff of Rates and Charges

OEB File No: EB-2018-0020

DATED: December 20, 2018

REVISED: January 4, 2019

Brantford Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2019

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0020

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	23.50
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019 Applicable only for Non-RPP Customers - Approved on an Interim Basis	$/kWh	(0.0030)
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019	$/kWh	0.0005
Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis	$/kWh	(0.0020)
Rate Rider for Disposition of Capacity Based Recovery Account (2019) - effective until December 31, 2019 Applicable only for Class B Customers - Approved on an Interim Basis	$/kWh	(0.0002)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0079
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0061

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Brantford Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2019
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0020

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to a non residential account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	30.77
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Distribution Volumetric Rate	$/kWh	0.0081
Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019 Applicable only for Non-RPP Customers - Approved on an Interim Basis	$/kWh	(0.0030)
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019	$/kWh	0.0009
Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis	$/kWh	(0.0020)
Rate Rider for Disposition of Capacity Based Recovery Account (2019) - effective until December 31, 2019 Applicable only for Class B Customers - Approved on an Interim Basis	$/kWh	(0.0002)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0070
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0054

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Brantford Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2019

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0020

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

The rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

The rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	236.93
Distribution Volumetric Rate	$/kW	2.8643
Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019 Applicable only for Non-RPP Customers - Approved on an Interim Basis	$/kWh	(0.0030)
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until December 31, 2019	$/kW	0.0766
Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 Applicable only for Non-Wholesale Market Participants - Approved on an Interim Basis	$/kW	(0.9771)
Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis	$/kW	0.2402

Brantford Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2019
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0020

Rate Rider for Disposition of Capacity Based Recovery Account (2019) - effective until December 31, 2019 Applicable only for Class B Customers - Approved on an Interim Basis	$/kW	(0.0557)
Retail Transmission Rate - Network Service Rate	$/kW	2.4118
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.8282

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Brantford Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2019

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EB-2018-0020

EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION

This classification applies to an electricity distributor licensed by the Ontario Energy Board that is provided electricity by means of this distributor's facilities. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Approved on an Interim Basis

Service Charge	$	362.56
Distribution Volumetric Rate	$/kW	2.0121
Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis	$/kW	0.2755
Retail Transmission Rate - Network Service Rate	$/kW	2.4118
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.8282

Brantford Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2019
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EB-2018-0020

microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator’s microFIT program and connected to the distributor’s distribution system. Further servicing details are available in the distributor’s Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.40

Brantford Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2019
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EB-2018-0020

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	4.24
Distribution Volumetric Rate	$/kW	20.3000
Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019 Applicable only for Non-RPP Customers - Approved on an Interim Basis	$/kWh	(0.0031)
Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis	$/kW	(0.6492)
Rate Rider for Disposition of Capacity Based Recovery Account (2019) - effective until December 31, 2019 Applicable only for Class B Customers - Approved on an Interim Basis	$/kW	(0.0544)
Retail Transmission Rate - Network Service Rate	$/kW	2.2521
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.7075

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Brantford Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2019

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EB-2018-0020

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photocells. The consumption for these customers will be based on the calculated load times the required lighting times established in the approved Ontario Energy Board street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	1.45
Distribution Volumetric Rate	$/kW	6.0789
Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019 Applicable only for Non-RPP Customers - Approved on an Interim Basis	$/kWh	(0.0030)
Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis	$/kW	(0.6505)
Rate Rider for Disposition of Capacity Based Recovery Account (2019) - effective until December 31, 2019 Applicable only for Class B Customers - Approved on an Interim Basis	$/kW	(0.0551)
Retail Transmission Rate - Network Service Rate	$/kW	2.3204
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.6878

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Brantford Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2019
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EB-2018-0020

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone boots, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information/ documentation with regard to electrical demand/consumption of the proposed unmetered load. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	13.12
Distribution Volumetric Rate	$/kWh	0.0091
Rate Rider for Disposition of Capacity Based Recovery Account (2019) - effective until December 31, 2019 Applicable only for Class B Customers - Approved on an Interim Basis	$/kWh	(0.0002)
Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 - Approved on an Interim Basis	$/kWh	(0.0022)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0042
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0054

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Brantford Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2019
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EB-2018-0020

STANDBY POWER SERVICE CLASSIFICATION

This classification refers to an account that has Load Displacement Generation and requires the distributor to provide back-up service. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component - Approved on an Interim Basis

Standby Charge - for a month where standby power is not provided. The charge is applied to the contracted amount (e.g. nameplate rating of the generation facility).	$/kW	1.7389

Brantford Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2019

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EB-2018-0020

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for Transformer Losses - applied to measured demand & energy	%	(1.00)

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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Customer Administration

Easement letter	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned cheque (plus bank charges)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account

Late payment - per month	%	1.50
Late payment - per annum	%	19.56
Collection of account charge - no disconnection	$	30.00
Disconnect/reconnect at meter - during regular hours	$	65.00
Disconnect/reconnect at meter - after regular hours	$	185.00
Disconnect/reconnect at pole - during regular hours	$	185.00
Disconnect/reconnect at pole - after regular hours	$	415.00
Install/remove load control device - during regular hours	$	65.00
Install/remove load control device - after regular hours	$	185.00

Other

Temporary service install & remove - overhead - no transformer	$	500.00
Temporary service - install & remove - underground - no transformer	$	300.00
Specific charge for access to the power poles - per pole/year (with the exception of wireless attachments)	$	43.63
Meter removal without authorization	$	60.00

Brantford Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2019

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EB-2018-0020

RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly fixed charge, per retailer	$	20.00
Monthly variable charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
up to twice a year	$	no charge
more than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0320
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0218

IRM Attachment E:

Proposed Tariff of Rates

Brantford Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2020
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2019-0022

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	23.71
Rate Rider for Recovery of Incremental Capital - effective until	$	1.75
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Retail Transmission Rate - Network Service Rate	$/kWh	0.0083
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0063

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Brantford Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2020
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EB-2019-0022

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to a non residential account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	31.05
Rate Rider for Recovery of Incremental Capital - effective until	$	3.98
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Distribution Volumetric Rate	$/kWh	0.0082
Retail Transmission Rate - Network Service Rate	$/kWh	0.0073
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0056

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Brantford Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2020

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EB-2019-0022

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

The rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

The rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	239.06
Rate Rider for Recovery of Incremental Capital - effective until	$	70.44
Distribution Volumetric Rate	$/kW	2.8901
Retail Transmission Rate - Network Service Rate	$/kW	2.5207
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.8793

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Brantford Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2020
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2019-0022

EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION

This classification applies to an electricity distributor licensed by the Ontario Energy Board that is provided electricity by means of this distributor's facilities. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Approved on an Interim Basis

Service Charge	$	365.82
Rate Rider for Recovery of Incremental Capital - effective until	$	1,215.36
Distribution Volumetric Rate	$/kW	2.0302
Retail Transmission Rate - Network Service Rate	$/kW	2.5207
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.8793

Brantford Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2020
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EB-2019-0022

microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.40

Brantford Power Inc.
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EB-2019-0022

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Further servicing details are available in the distributor’s Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	4.28
Rate Rider for Recovery of Incremental Capital - effective until	$	0.45
Distribution Volumetric Rate	$/kW	20.4827
Retail Transmission Rate - Network Service Rate	$/kW	2.3537
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.7552

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

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TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2020
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EB-2019-0022

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photocells. The consumption for these customers will be based on the calculated load times the required lighting times established in the approved Ontario Energy Board street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	1.46
Rate Rider for Recovery of Incremental Capital - effective until	$	0.25
Distribution Volumetric Rate	$/kW	6.1336
Retail Transmission Rate - Network Service Rate	$/kW	2.4251
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.7350

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

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EB-2019-0022

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone boots, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information/ documentation with regard to electrical demand/consumption of the proposed unmetered load. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	13.24
Rate Rider for Recovery of Incremental Capital - effective until	$	1.18
Distribution Volumetric Rate	$/kWh	0.0092
Retail Transmission Rate - Network Service Rate	$/kWh	0.0044
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0056

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

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EB-2019-0022

STANDBY POWER SERVICE CLASSIFICATION

This classification refers to an account that has Load Displacement Generation and requires the distributor to provide back-up service. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

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MONTHLY RATES AND CHARGES - Delivery Component - Approved on an Interim Basis

Standby Charge - for a month where standby power is not provided. The charge is applied to the contracted amount (e.g. nameplate rating of the generation facility).	$/kW	1.7546

Brantford Power Inc.
TARIFF OF RATES AND CHARGES
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ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for Transformer Losses - applied to measured demand & energy	%	(1.00)

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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Customer Administration

Easement letter	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned cheque (plus bank charges)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account

Late payment - per month	%	1.50
Late payment - per annum	%	19.56
Collection of account charge - no disconnection	$	30.00
Disconnect/reconnect at meter - during regular hours	$	65.00
Disconnect/reconnect at meter - after regular hours	$	185.00
Disconnect/reconnect at pole - during regular hours	$	185.00
Disconnect/reconnect at pole - after regular hours	$	415.00
Install/remove load control device - during regular hours	$	65.00
Install/remove load control device - after regular hours	$	185.00

Other

Temporary service install & remove - overhead - no transformer	$	500.00
Temporary service - install & remove - underground - no transformer	$	300.00
Specific charge for access to the power poles - per pole/year (with the exception of wireless attachments)	$	44.15
Meter removal without authorization	$	60.00

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RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	101.20
Monthly fixed charge, per retailer	$	40.48
Monthly variable charge, per customer, per retailer	$/cust.	1.01
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.61
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.61)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.51
Processing fee, per request, applied to the requesting party	$	1.01
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
up to twice a year	$	no charge
more than twice a year, per request (plus incremental delivery costs)	$	4.05

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.032
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0218

IRM Attachment F:

Supporting RRR and Rate Order Excerpts

File Number:	0
Exhibit:	
Tab:	
Schedule:	
Page:	
Date:	

Appendix 2-H
Other Operating Revenue

USoA #	USoA Description	2013 Actual	Actual Year²	Actual Year²	Actual Year	Bridge Year²	Test Year
		2013	2014	2014	2015	2016	2017
	Reporting Basis	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
4235	Specific Service Charges	-$ 441,756	-$ 539,109	-$ 539,109	-$ 650,019	-$ 520,272	-$ 651,903
4225	Late Payment Charges	-$ 152,695	-$ 207,146	-$ 207,146	-$ 219,014	-$ 226,236	-$ 235,599
4080	SSS Revenue	-$ 106,572	-$ 108,547	-$ 108,547	-$ 111,559	-$ 110,820	-$ 111,730
4082	Retail Services Revenues	-$ 36,888	-$ 46,483	-$ 46,483	-$ 44,303	-$ 41,369	-$ 41,376
4084	Service Tax Requests	-$ 17,103	-$ 16,257	-$ 16,257	-$ 15,882	-$ 9,506	-$ 9,589
4090	Electric Services Incidental to Energy Sales	$ -	$ -	$ -	$ -	$ -	$ -
4205	Interdepartmental Rents	$ -	$ -	$ -	$ -	$ -	$ -
4210	Rent from Electic Property	-$ 107,996	-$ 108,645	-$ 108,645	-$ 109,740	-$ 99,527	-$ 101,517
4215	Other Utility Operating Income	$ -	$ -	$ -	$ -	$ -	$ -
4220	Other Electric Revenues	$ -	$ 929	$ 929	$ -	$ -	$ -
4240	Provision for Rate Refunds	$ -	$ -	$ -	$ -	$ -	$ -
4245	Government Assistance Directly Credited to Income	$ -	$ -	$ -	$ -	$ -	$ -
4305	Regulatory Debits	$ -	$ -	$ -	$ -	$ -	$ -
4310	Regulatory Credits	$ -	$ -	$ -	$ -	$ -	$ -
4315	Revenues from Electric Plant Leased to Others	$ -	$ -	$ -	$ -	$ -	$ -
4320	Expenses of Electric Plant Leased to Others	$ -	$ -	$ -	$ -	$ -	$ -
4325	Revenues from Merchandise, Jobbing, Etc.	$ -	$ -	$ -	$ -	$ -	$ -
4330	Costs and Expenses of Merchandising, Jobbing, Etc	$ -	$ -	$ -	$ -	$ -	$ -
4335	Profits and Losses from Financial Instrument Hedges	$ -	$ -		$ -	$ -	$ -
4340	Profits and Losses from Financial Instrument Investments	$ -	$ -	$ -	$ -	$ -	$ -
4345	Gains from Disposition of Future Use Utility Plant	$ -	$ -	$ -	$ -	$ -	$ -
4350	Losses from Disposition of Future Use Utility Plant	$ -	$ -	$ -	$ -	$ -	$ -
4355	Gain on Disposition of Utility and Other Property	-$ 12,687	-$ 13,477	-$ 13,477	-$ 39,464	$ 10,000	-$ 15,000
4360	Loss on Disposition of Utility and Other Property	$ -	$ -	$ -	$ -	$ -	$ -
4365	Gains from Disposition of Allowances for Emission	$ -	$ -	$ -	$ -	$ -	$ -
4370	Losses from Disposition of Allowances for Emission	$ -	$ -	$ -	$ -	$ -	$ -
4375	Revenues from Non-Utility Operations	-$ 2,985,434	-$ 3,493,082	-$ 3,493,082	-$ 2,947,370	-$ 2,164,668	-$ 2,021,948
4380	Expenses from Non-Utility Operations	$ 3,097,191	$ 3,618,390	$ 3,618,390	$ 2,990,804	$ 2,164,669	$ 2,021,948
4385	Expenses of Non-Utility Operations	$ -	$ -	$ -	$ -	$ -	$ -
4390	Miscellaneous Non-Operating Income	-$ 7,493	-$ 6,511	-$ 6,511	-$ 56,029	-$ 15,000	-$ 15,300
4395	Rate-Payer Benefit Including Interest	$ -	$ -	$ -	$ -	$ -	$ -
4398	Foreign Exchange Gains and Losses, Including Amortization	$ -	$ -	$ -	$ -	$ -	$ -
4405	Interest and Dividend Income	-$ 354,063	-$ 249,186	-$ 249,186	-$ 203,279	-$ 138,337	-$ 132,986
4415	Equity in Earnings of Subsidiary Companies	$ -	$ -		$ -	$ -	$ -
Specific Service Charges		-$ 441,756	-$ 539,109	-$ 539,109	-$ 650,019	-$ 520,272	-$ 651,903
Late Payment Charges		-$ 152,695	-$ 207,146	-$ 207,146	-$ 219,014	-$ 226,236	-$ 235,599
Other Operating Revenues		-$ 268,559	-$ 279,002	-$ 279,002	-$ 281,484	-$ 261,222	-$ 264,212
Other Income or Deductions		-$ 262,486	-$ 143,866	-$ 143,866	-$ 255,338	-$ 143,336	-$ 163,286
Total		-$ 1,125,496	-$ 1,169,123	-$ 1,169,123	-$ 1,405,856	-$ 1,151,066	-$ 1,315,000

Description	Account(s)
Specific Service Charges:	4235
Late Payment Charges:	4225
Other Distribution Revenues:	4080, 4082, 4084, 4090, 4205, 4210, 4215, 4220, 4240, 4245
Other Income and Expenses:	4305, 4310, 4315, 4320, 4325, 4330, 4335, 4340, 4345, 4350, 4355, 4360, 4365, 4370, 4375, 4380, 4385, 4390, 4395, 4398, 4405, 4415

Note: Add all applicable accounts listed above to the table and include all relevant information.

Account Breakdown Details

For each "Other Operating Revenue" and "Other Income or Deductions" Account, a detailed breakdown of the account components is required. See the example below for Account 4405, Interest and Dividend Income.

Account 4080 -SSS Revenue

	2013 Actual	Actual Year²	Actual Year²	Actual Year	Bridge Year²	Test Year
	2013	2014	2014	2015	2016	2017

Reporting Basis	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
RESIDENTIAL REV - SSS	-$ 96,602	-$ 98,395	-$ 98,395	-$ 99,745	-$ 100,530	-$ 101,410
GEN SERV <50KW REV - SSS	-$ 7,556	-$ 7,684	-$ 7,684	-$ 7,732	-$ 7,770	-$ 7,800
G. S. UNMETERED REV SSS	-$ 1,316	-$ 1,299	-$ 1,299	-$ 1,293	-$ 1,320	-$ 1,320
GEN SERV >50KW REV - SSS	-$ 978	-$ 1,050	-$ 1,050	-$ 1,065	-$ 1,080	-$ 1,080
STREET LIGHT REV - SSS	-$ 3	-$ 3	-$ 3	-$ 3	$ -	$ -
SENTINEL LIGHT REV - SSS	-$ 111	-$ 111	-$ 111	-$ 1,717	-$ 120	-$ 120
GEN SERV>5000KW REV - SSS	-$ 7	-$ 7	-$ 7	-$ 4	$ -	$ -
Total	-$ 106,572	-$ 108,549	-$ 108,549	-$ 111,559	-$ 110,820	-$ 111,730

Account 4082 -Retail Services Revenue

	2013 Actual	Actual Year[2]	Actual Year[2]	Actual Year	Bridge Year[2]	Test Year
	2013	2014	2014	2015	2016	2017
Reporting Basis	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
RSVA ADJUSTMENT	$ 238	-$ 12,763	-$ 12,763	-$ 12,398	-$ 8,801	-$ 8,808
RTLR(9)-STANDARD CHARGE	$ -	$ -	$ -	-$ 100	$ -	$ -
RTLR(9)-DCBR BILL READY CHARGE	-$ 12,026	-$ 10,714	-$ 10,714	-$ 9,932	-$ 10,236	-$ 10,236
RTLR(9)-MONTHLY FIXED CHARGE	-$ 4,260	-$ 4,109	-$ 4,109	-$ 4,332	-$ 4,320	-$ 4,320
RTLR(9)-MONTHLY VARIABLE CHRG	-$ 20,840	-$ 18,898	-$ 18,898	-$ 17,542	-$ 18,012	-$ 18,012
Total	-$ 36,888	-$ 46,483	-$ 46,483	-$ 44,303	-$ 41,369	-$ 41,376

Account 4084 -Service Tax Requests

	2013 Actual	Actual Year[2]	Actual Year[2]	Actual Year	Bridge Year[2]	Test Year
	2013	2014	2014	2015	2016	2017
Reporting Basis	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
RSVA ADJUSTMENT	-$ 16,105	-$ 15,390	-$ 15,390	-$ 15,147	-$ 9,098	-$ 9,181
RTLR(9)-ACCEPT FEE	-$ 571	-$ 511	-$ 511	-$ 443	-$ 252	-$ 252
RTLR(9)-REQUEST FEE	-$ 427	-$ 355	-$ 355	-$ 293	-$ 156	-$ 156
Total	-$ 17,103	-$ 16,257	-$ 16,257	-$ 15,882	-$ 9,506	-$ 9,589

Account 4220 -Other Electric Revenue

	2013 Actual	Actual Year[2]	Actual Year[2]	Actual Year	Bridge Year[2]	Test Year
	2013	2014	2014	2015	2016	2017
Reporting Basis	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
OCCUPANCY/COLLECTION REVENUE	$ -	$ 929	$ 929	$ -	$ -	$ -
Total	$ -	$ 929	$ 929	$ -	$ -	$ -

Account 4405 - Interest and Dividend Income

	2013 Actual	Actual Year[2]	Actual Year[2]	Actual Year	Bridge Year[2]	Test Year
	2013	2014	2014	2015	2016	2017
Reporting Basis	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
INTEREST ON INCOME TAXES	-$ 6,701	$ -	$ -			
INTEREST ON A/R	-$ 4,298	$ 497	$ 497	-$ 7,027	-$ 7,000	-$ 7,140
INVESTMENT INCOME	-$ 199,521	-$ 173,887	-$ 173,887	-$ 126,219	-$ 131,337	-$ 125,846
Total	-$ 210,520	-$ 173,390	-$ 173,390	-$ 133,246	-$ 138,337	-$ 132,986

Account 4210 - Rent from Electric Property

	2013 Actual	Actual Year[2]	Actual Year[2]	Actual Year	Bridge Year[2]	Test Year
	2013	2014	2014	2015	2016	2017
Reporting Basis	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
Pole Rental Revenues Affiliates	-$ 45,125	-$ 45,773	-$ 45,773	-$ 46,399	-$ 47,624	-$ 48,576
Pole Rental Revenues Other	-$ 62,872	-$ 62,872	-$ 62,872	-$ 63,341	-$ 51,903	-$ 52,941
Total	-$ 107,996	-$ 108,645	-$ 108,645	-$ 109,740	-$ 99,527	-$ 101,517

Account 4225 - Late Payment Charges

	2013 Actual	Actual Year[2]	Actual Year[2]	Actual Year	Bridge Year[2]	Test Year
	2013	2014	2014	2015	2016	2017
Reporting Basis	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
Late Payment Charges	-$ 152,695	$ 207,146	$ 207,146	-$ 219,014	-$ 226,236	-$ 235,599
Total	-$ 152,695	$ 207,146	$ 207,146	-$ 219,014	-$ 226,236	-$ 235,599

Account 4235 - Miscellaneous Service Revenues

	2013 Actual	Actual Year[2]	Actual Year[2]	Actual Year	Bridge Year[2]	Test Year
	2013	2014	2014	2015	2016	2017
Reporting Basis	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
ARREARS CERTIFICATE REVENUE	-$ 1,340	-$ 435	-$ 435	-$ 126	-$ 135	-$ 135
CREDIT CHECK FEE	-$ 2,865	-$ 2,870	-$ 2,870	-$ 3,240	-$ 3,583	-$ 3,655
RETURNED CHEQUE CHARGE	-$ 5,715	-$ 5,795	-$ 5,795	-$ 5,026	-$ 5,891	-$ 6,009
NEW A/C SET UP FEE	-$ 158,745	-$ 156,060	-$ 156,060	-$ 163,072	-$ 160,222	-$ 163,426
FIELD COLLECTION CHARGE	-$ 244,886	-$ 333,900	-$ 333,900	-$ 440,550	-$ 313,393	-$ 440,889
RECONNECTION CHARGE	-$ 12,555	-$ 17,095	-$ 17,095	-$ 15,743	-$ 15,984	-$ 16,304
ELECTRIC RECONNECT AFTER HOURS	-$ 8,325	-$ 14,245	-$ 14,245	-$ 12,580	-$ 12,077	-$ 12,319

RECONNECT AT POLE	-$ 925	$ -	$ -			
TEMP HYDRO SERVICE CHARGE	-$ 2,500	-$ 3,000	-$ 3,000	-$ 3,500	-$ 3,121	-$ 3,183
TEMP U/G SERVICE CHARGE	$ -	-$ 600	-$ 600	-$ 300		
ENERGY SALES	-$ 3,901	-$ 5,109	-$ 5,109	-$ 5,822	-$ 5,866	-$ 5,983
OTHER	$ -	$ -	$ -	-$ 60	$ -	$ -
Total	-$ 441,756	-$ 539,109	-$ 539,109	-$ 650,019	-$ 520,272	-$ 651,903

Account 4355-Gain on Disposition of Utility and Other Property

	2013 Actual	Actual Year²	Actual Year²	Actual Year	Bridge Year²	Test Year
	2013	2014	2014	2015	2016	2017
Reporting Basis	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
Gain on Disposition of Utility and Other Property	-$ 12,687	-$ 13,477	-$ 13,477	-$ 39,464	-$ 10,000	-$ 15,000
Total	-$ 12,687	-$ 13,477	-$ 13,477	-$ 39,464	-$ 10,000	-$ 15,000

Account 4375- Revenue from Non-Utility Operations

	2013 Actual	Actual Year²	Actual Year²	Actual Year	Bridge Year²	Test Year
	2013	2014	2014	2015	2016	2017
Reporting Basis	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
Affiliate Allocations	$ -	-$ 85,811	-$ 85,811	-$ 410,229	-$ 384,269	-$ 306,988
New Building Rental Income- Non-Utility					$ -	$ -
CDM Bonus	-$ 2,985,434	-$ 3,407,271	-$ 3,407,271	-$ 2,537,141	-$ 1,580,232	-$ 1,610,428
Adjustment to offset BEC Management Fees in 4380 and bad debt expense for affiliates					-$ 200,167	-$ 104,532
Adjustment to offset New Building Operational Cost-Non-Utility in 4380						$ -
Total	-$ 2,985,434	-$ 3,493,082	-$ 3,493,082	-$ 2,947,370	-$ 2,164,668	-$ 2,021,948

Account 4380-Expenses from Non-Utility Operations

	2013 Actual	Actual Year²	Actual Year²	Actual Year	Bridge Year²	Test Year
	2013	2014	2014	2015	2016	2017
Reporting Basis	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
CDM Bonus	$ 2,978,691	$ 3,407,271	$ 3,407,271	$ 2,283,588	$ 1,580,232	$ 1,610,428
Bad Debt Expense	$ -	$ -	$ -	$ 136,261	$ 96,810	$ -
New Building Operational Cost- Non-Utility	$ -	$ -	$ -	$ -	$ -	$ -
Affiliate Allocations	$ -	$ 85,811	$ 85,811	$ 410,229	$ 384,269	$ 306,988
BEC Management Fees	$ 118,500	$ 125,308	$ 125,308	$ 160,727	$ 103,357	$ 104,532
Total	$ 3,097,191	$ 3,618,390	$ 3,618,390	$ 2,990,805	$ 2,164,669	$ 2,021,948

Account 4390-Miscellaneous Non-Operating Income

	2013 Actual	Actual Year²	Actual Year²	Actual Year	Bridge Year²	Test Year
	2013	2014	2014	2015	2016	2017
Reporting Basis	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
Sales of Scrap	-$ 7,493	-$ 6,511	-$ 6,511	-$ 15,410	-$ 15,000	-$ 15,300
Other	$ -	$ -	$ -	-$ 40,619	$ -	$ -
Total	-$ 7,493	-$ 6,511	-$ 6,511	-$ 56,029	-$ 15,000	-$ 15,300

Notes:

1 List and specify any other interest revenue.

2 2015, 2014 must be presented in both a CGAAP and MIFRS basis.

Clicking Save or Apply will not automatically submit this filing. To SUBMIT this filing, scroll to the end of the page, select Yes in the Submit drop down then click the SAVE button.

Click here for tips and examples (from RRR Filing

Table 1a

SSS Metered Consumption by Detailed Rate Class

Please enter metered consumption from SSS customers based on your distributor's detailed rate classes.

The figures entered in Table 1a will populate Table 1b on an aggregated basis.

Detailed Rate Class	Metered consumption for customers on RPP kWh (a)	Metered consumption for customers on RPP kW (b)	Metered consumption for customers Not on RPP kWh (c)	Metered consumption for customers Not on RPP kW (d)	Metered consumption for customers billed by IESO for commodity kWh (e)	Metered consumption for customers billed by IESO for commodity kW (f)	Total Consumption for Distribution Customers KWh (g=a+c+e)	Total Consumption for Distribution Customers KW (h=b+d+f)
Residential	289979565.70		0.00				289979565.70	0.00
General Service Less Than 50 kW	82456911.90		254548.20				82711460.10	0.00
General Service 50 to 4,999 kW	36929489.60	106844.50	356247686.90	994672.10	6330357.00	12258.40	399507533.40	1113775.00
Sentinel Lighting	190022.90	520.30					190022.90	520.30
Street Lighting			7191580.00	22227.00			7191580.00	22227.00
Unmetered Scattered Load	1497429.00						1497429.00	0.00
Embedded Distributor					41227723.00	95218.60	41227723.00	95218.60

Table 1b

SSS Metered Consumption by Generic Rate Class

Table 1b will be auto-populated when entries in Table 1a are entered and saved.

Please verify that the classes in Table 1a have been accurately aggregated into the generic class groupings identified below.

Generic Rate Class	Metered consumption for customers on RPP kWh (i)	Metered consumption for customers on RPP kW (j)	Metered consumption for customers Not on RPP kWh (k)	Metered consumption for customers Not on RPP kW (l)	Metered consumption for customers billed by IESO for commodity kWh (m)	Metered consumption for customers billed by IESO for commodity kW (n)	Total Consumption for Distribution Customers KWh (o=i+k+m)	Total Consumption for Distribution Customers KW (p=j+l+n)
Residential	289979565.70	0.00	0.00	0.00	0.00	0.00	289979565.70	0.00
General Service < 50 kW	82456911.90	0.00	254548.20	0.00	0.00	0.00	82711460.10	0.00
General Service >= 50 kW	36929489.60	106844.50	356247686.90	994672.10	6330357.00	12258.40	399507533.40	1113775.00
Large User							0.00	0.00
Sub Transmission Customers							0.00	0.00
Embedded Distributor(s)	0.00	0.00	0.00	0.00	41227723.00	95218.60	41227723.00	95218.60
Street Lighting Connections	0.00	0.00	7191580.00	22227.00	0.00	0.00	7191580.00	22227.00
Sentinel Lighting Connections	190022.90	520.30	0.00	0.00	0.00	0.00	190022.90	520.30
Unmetered Scattered Load Connections	1497429.00	0.00	0.00	0.00	0.00	0.00	1497429.00	0.00
Total (Auto-Calculated)	411053419.10	107364.80	363693815.10	1016899.10	47558080.00	107477.00	822305314.20	1231740.90

Energy Sales with Retailer

Please enter metered consumption for customers successfully enrolled with a retailer broken down by individual retailer.

+	Retailer	Is this Retailer complete?	Total kWhs	Total kWs	

➪	Active Energy Inc.	Yes	12050397.30	26338.00	✕
➪	Bruce Power Inc.	Yes	53218548.20	95855.20	✕
➪	Direct Energy Marketing Inc.	Yes	4653956.70	4985.80	✕
➪	ECNG Inc.	Yes	40462232.00	88367.00	✕
➪	Hudson Energy Canada Corp.	Yes	25620145.10	96433.40	✕
➪	Planet Energy (Ontario) Corp.	Yes	1395071.60	762.90	✕
➪	Just Energy Ontario L.P.	Yes	10750627.80	1106.40	✕
➪	Canadian Hydro Ltd.	Yes	436924.80	1529.50	✕
➪	Onit Energy Ltd.	Yes	7287292.90	13501.50	✕
➪	Summitt Energy Management Inc. on behalf of Summitt Energy LP	Yes	3660090.10	4848.40	✕
➪	Superior Energy Management Electricity LP	Yes	0.00	0.00	✕
➪	Sunwave Gas & Power Inc.	Yes	168702.00	0.00	✕
➪	Gas Ontario Inc.	Yes	59519.50	0.00	✕

Have you entered all retailers?

Yes

Please note that Table 2a (“Aggregate Consumption with Retailers”) and Table 3b (“Total Metered Consumption”) will not update unless you have answered “Yes” and saved the form.

Table 2a

Aggregated Consumption of Retailer Customers by Generic Rate Class

The figures in Table 2a are auto-calculated. When all retailer tables have been entered, select "Yes" above and click Save to record the entries from each retailer table and allow Table 2a to be populated.

Please verify that the classes have been accurately aggregated into the generic class groupings identified below.

Generic Rate Class	Metered Consumption in kWhs (q)	Metered Consumption in kWs (r)
Residential	11330956.90	0.00
General Service < 50 kW	12017128.00	0.00
General Service >= 50 kW	136415423.00	333728.10
Large User	0.00	0.00
Sub Transmission Customers	0.00	0.00
Embedded Distributor(s)	0.00	0.00
Street Lighting Connections	0.00	0.00
Sentinel Lighting Connections	0.00	0.00

Unmetered Scattered Load Connections	0.00	0.00
Total (Auto-Calculated)	159763507.90	333728.10

Table 2b

Aggregated Consumption from Retailer Customers by Detailed Rate Class

Please enter aggregate consumption from retailer customers based on your distributor's detailed rate class.

These figures are entered to populate Table 3a which will be used to further streamline the application process for formulaic adjustments to rates during an incentive rate-setting period.

Detailed Rate Class	Metered Consumption in kWhs (s)	Metered Consumption in kWs (t)
Residential	11330956.90	
General Service Less Than 50 kW	12017128.00	
General Service 50 to 4,999 kW	136415423.00	333728.10
Sentinel Lighting		
Street Lighting		
Unmetered Scattered Load		
Embedded Distributor		

Table 3a

Total Metered Consumption (SSS + Retailer) by Detailed Rate Class

Metered consumption in kWhs and kW will auto-populate from Table 1a and Table 2b

The data populated in Table 3a will be used to further streamline the application process for formulaic adjustments to rates during an incentive rate-setting period.

Detailed Rate Class	Metered consumption in kWhs (u=g+s)	Metered consumption in kWs (v=h+t)
Residential	301310522.60	0.00
General Service Less Than 50 kW	94728588.10	0.00
General Service 50 to 4,999 kW	535922956.50	1447503.10
Sentinel Lighting	190022.90	520.30
Street Lighting	7191580.00	22227.00
Unmetered Scattered Load	1497429.00	0.00
Embedded Distributor	41227723.00	95218.60

Table 3b

Total Metered Consumption (SSS + Retailer) and Annual Billings by Generic Rate Class

Metered consumption in kWhs and kW will auto-populate from Table 1b and Table 2a.

Please input Annual Billings for each generic rate class. The sum of annual billings for all rate classes should equal Account 4080 from the RRR 2.1.7 Trial Balance.

Generic Rate Class	Metered consumption in kWhs (w=o+q)	Metered consumption in kWs (x=p+r)	Annual Bilings - Distribution Revenue (Acct. 4080)
Residential	301310522.60	0.00	10180620.00
General Service < 50 kW	94728588.10	0.00	1682379.00
General Service >= 50 kW	535922956.50	1447503.10	4814488.00
Large User	0.00	0.00	
Sub Transmission Customers	0.00	0.00	
Embedded Distributor(s)	41227723.00	95218.60	140343.00
Street Lighting Connections	7191580.00	22227.00	232095.00
Sentinel Lighting Connections	190022.90	520.30	37436.00
Unmetered Scattered Load Connections	1497429.00	0.00	78805.00
Total (Auto-Calculated)	982068822.10	1565469.00	17166166.00

Table 4 Wholesale Market Participants

Please report Metered kWhs, Metered kWs and annual billings ($) for wholesale market participants connected to the distributor's distribution system.

Metered kWhs: 47558080.00

Metered kWs: 107477.00

Annual Billings (in dollars): 40331.00

Table 5 Class A Consumption

Please report the aggregate consumption and demand for Class A customers

Metered kWhs: 186988209.29

Metered kWs: 395519.80

Checklist | Input Appendices | **ROE Summary** | Over Earning Drivers | Under Earning Drivers

Instructions

A distributor shall report, in the form and manner determined by the OEB, the Regulated Return on Equity (ROE) earned in the reporting year.

The reported ROE is to be calculated on the same basis as was used in the distributor's last Cost of Service (CoS).

The sign of the input cells are to be aligned with the sign of the accounts reported in RRR 2.1.7. Generally, revenue/gain items are to be entered as negative numbers and expense/loss items are to be entered as positive numbers.

Please read the RRR Filing Guide for the detailed guidance on the inputs of the form and appendices.

Click here for tips and examples (from RRR Filing Guide).

Information from the distributor's last CoS Decision and Order and the successfully submitted RRR 2.1.7 trial balance have been pre-populated in this form.

Please review each input for accuracy and contact Industry Relations Enquiry if you have any questions.

CoS Decision and Order Info

			Data Source
The CoS Decision and Order EB number for the ROE	xx	EB-2016-0058	CoS Decision and Order (last CoS establishing the current reporting year's base rates)
Accounting standard used in CoS Decision and Order	yy	MIFRS	CoS Decision and Order

Regulated Net Income

			Data Source
Regulated net income (loss), as per RRR 2.1.7	a	1963215.86	RRR 2.1.7 - USoA 3046 * (-1)
Adjustment items:			
Non-rate regulated items and other adjustments (Appendix 1)	b	-55925.53	Appendix 1 cell (aq)

Unrealized (gains)/losses on interest rate swaps (Not applicable if recorded in Other Comprehensive Income)	c	-42124.57	Please provide USoAs: 4390
Actuarial (gains)/losses on OPEB and/or Pensions not approved by the OEB	d	-1574.00	Please provide USoAs: Various
Non-recoverable donations (Appendix 2)	e	9387.75	Appendix 2 cell (be)
Net interest/carrying charges from DVAs (Appendix 3)	f	51605.25	Appendix 3 cell (cc)
Interest adjustment for deemed debt (Appendix 4)	g	-149322.56	Appendix 4 cell (dg)
Adjusted regulated net income before tax adjustments	h=a+b+c+d+e+f+g	1775262.20	
Add back:			
Future/deferred taxes expense	i	-67549.00	RRR 2.1.7 - USoA 6115
Current income tax expense (Does not include future income tax)	j	575283.00	RRR 2.1.7 - USoA 6110
Deduct:			
Current income tax expense for regulated ROE purposes (Appendix 6)	k	-67656.14	Appendix 6 cell (fq)
Adjusted regulated net income	l=h+i+j-k	2350652.34	

Deemed Equity

Rate base:			**Data Source**
Cost of power	m	109290238.94	RRR 2.1.7 - Sum of USoA 4705-4751 inclusive
			RRR 2.1.7 - Sum of USoA 4505-4640, 4805-5695, 6105, 6205, 6210, and

Operating expenses before any applicable adjustments		n1 10791928.46	6225, then subtract ROE Summary cell (d) and subtract ROE Summary cell (e)
Other Adjustments:			
		n2	Please provide USoAs
Adjusted operating expenses		n=n1-n2 10791928.46	
Total Cost of Power and Operating Expenses		o=m+n 120082167.40	
Working capital allowance % as approved in the last CoS Decision and Order		% p 7.50	CoS Decision and Order
Total working capital allowance ($)		q=o*p 9006162.55	
PP&E			
Opening balance - regulated PP&E (NBV) (Appendix 5)		r 65184864.63	Appendix 5 cell (ec)
Adjusted closing balance - regulated PP&E (NBV) (Appendix 5)		s 65568604.31	Appendix 5 cell (el)
Average regulated PP&E		t=(r+s)/2 65376734.47	
Total rate base		u=q+t 74382897.02	
Regulated deemed short-term debt % and $	% v 4.00	v1=v*u 2975315.88	Cell (v) from CoS Decision and Order
Regulated deemed long-term debt % and $	% w 56.00	w1=w*u 41654422.33	Cell (w) from CoS Decision and Order
Regulated deemed equity % and $	% x 40.00	x1=x*u 29753158.81	Cell (x) from CoS Decision and order

Regulated Rate of Return on Deemed Equity (ROE)

		Data Source
Achieved ROE %	% y=l/x1 7.90	
Deemed ROE % from the distributor's last CoS Decision and Order	% z 8.78	CoS Decision and Order
Difference - maximum deadband 3%	% z1=y-z -0.88	
ROE status for the year (Over-earning/Under-earning/Within 300 basis points deadband)	z2 Within	If the distributor is in an over-earning position as indicated in cell (z2), please complete Appendices 7 & 8. If the distributor is in an under-earning position as indicated in cell (z2), please complete Appendices 9 & 10.

IRM Attachment G:

KPMG Substantively Enacted Tax as at June 30, 2019

Please refer to the following web address for this attachment:

https://home.kpmg/content/dam/kpmg/ca/pdf/2019/07/substantively-enacted-income-tax-rates-for-ccpc-for-2019-and-beyond.pdf

IRM Attachment H:

1595 Analysis Work Form

Ontario Energy Board

1595 Analysis Workform

Version 1.0

Account 1595 Analysis Workform

Input cells

Drop down cells

Utility Name Brantford Power Inc.

Utility name must be selected

Please select "yes" for the 1595 Rate Years being Requested for Disposition

2012	No
2013	No
2014	No
2015	No
2016	No
2017	Yes

Ontario Energy Board

1595 Analysis Workform

Components of the 1595 Account Balances:		Principal Balance Approved for Disposition	Carrying Charges Balance Approved for Disposition	Total Balances Approved for Disposition	Rate Rider Amounts Collected/(Returned)	Residual Balances Pertaining to Principal and Carrying Charges Approved for Disposition	Carrying Charges Recorded on Net Principal Account Balances	Total Residual Balances	Collections/Returns Variance (%)
Total Group 1 and Group 2 Balances excluding Account 1589 - Global Adjustment		-$2,778,621	$25,564	-$2,753,057	-$2,798,935	$45,878	-$16,111	**$29,767**	**-1.7%**
Account 1589 - Global Adjustment		$1,613,940	$24,341	$1,638,281	$1,559,629	$78,652	$7,358	**$86,011**	**4.8%**
Total Group 1 and Group 2 Balances		-$1,164,681	$49,905	-$1,114,776	-$1,239,306	$124,530	-$8,752	**$115,778**	**-11.2%**
							Total residual balance per continuity schedule:	$115,779	
							Difference (any variance should be explained):	**$1**	

*Unresolved differences of +/- 10% require further analysis and explanation. Amounts originally approved for disposition based on forecasted consumption or number of customers must be compared to actual figures.

Additional Notes and Comments

Note the $1 is a result of rounding

IRM Attachment I:

Completed 2020 IRM Application Completion Checklist

2020 IRM Checklist
Brantford Power Inc.
EB-2019-0022

Date: August 12, 2019

Filing Requirement Page # Reference		Evidence Reference, Notes
IRM REQUIREMENTS		
3.1.2 Components of the Application Filing , Pg. 3-4		
Pg. 3	Manager's summary documenting and explain all rate adjustments requested	Section 1.0
3	Contact info - primary contact may be a person within the applicant's organization other than the primary license contact	page 4
4	Completed Rate Generator Model and supplementary work forms, Excel and PDF	Attachment B
4	Current tariff sheet, PDF	Attachment D
4	Supporting documentation (e.g. relevant past decisions, RRWF etc.)	Attachment F
4	Statement as to who will be affected by the application, specific customer groups affected by particular request	section 1.1
4	Applicant's internet address	page 4
4	Statement confirming accuracy of billing determinants pre-populated in model	section 1.3
4	Text searchable PDF format for all documents	yes, where applicable.
3.1.3 Applications and Electronic Models, Pg. 5-6		
5	Populated GA Analysis Workform	No- please see Cover letter. BPI is working to complete this however th GA analysis is not requested for disposition.
5	If required, for distributors seeking revenue to cost ratio adjustments due to previous OEB decision, the Revenue to Cost Ratio Adjustment Workform must be filed	N/A- 1.5.2
5	For an incremental or pre-approved advanced capital module (ICM/ACM) cost recovery and associated rate rider(s), a distributor must file the Capital Module Applicable to ACM and ICM	ICM Appendix G
5	A distributor seeking to dispose of lost revenue amounts from conservation and demand management activities, during an IRM term, must file the Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) Workform	N/A- 1.5.7 -- not applying
5 & 6	Account 1595 Analysis Workform - for distributors who meet the requirements for disposition of residual balances in 1595 sub-accounts	IRM Attachment I; section 1.5.6
Addendum, Page 15	All distributors must file the responses to the questions in Appendix A of the GA Analysis Workform.	No- please see Cover letter. BPI is working to complete this however th GA analysis is not requested for disposition.
3.2.2 Revenue to Cost Ratio Adjustments		
8	Completed revenue-to-cost ratio adjustment workform to adjust the revenue-to-cost ratio if previously approved by the OEB	N/A Section 1.5.2
3.2.3 Rate Design for Residential Electricity Customers		
	Residential Rate Design - Exceptions and Mitigation (applicable only to distributors that have not completed the rate design transition)	Completed in 2019 rates
9	Extension of OEB-approved transition period, if necessary	N/A
9	Alternative/additional strategy in the event that an additional transition year is insufficient, or that no extension is necessary, however substantiated with reasons	N/A
9	Calculation of the combined impact of the fixed rate increase and any other changes in the cost of distribution service for those residential RPP customers who are at the 10th percentile of overall consumption	N/A
9	Description of the method used to derive the 10th consumption percentile. The description should include a discussion regarding the nature of the data that was used (e.g. was the source data for all residential customers or a representative sample of residential customers).	N/A
9	If the total bill impact of the elements proposed in the application is 10% or greater for RPP customers consuming at the 10th percentile, a distributor must file a plan to mitigate the impact for the whole residential class or indicate why such a plan is not required	N/A
10	Mitigation plan if total bill increases for any customer class exceed 10%	N/A
3.2.4 Electricity Distribution Retail Transmission Se	No action required at filing - model completed with most recent uniform transmission rates (UTRs) approved by the OEB	
3.2.5 Review and Disposition of Group 1 DVA Balances, Pg. 10-16		
10	Justification if any account balance in excess of the threshold should not be disposed	Confirmed no balances disposed due to threshold test not being met (table 1.5.6-B)
11	Completed tab 3 - continuity schedule in Rate Generator Model	IRM Attachment B
11	Explanation of variance between amounts proposed for disposition and amounts reported in RRR for each account	Section 1.5.6, table 1.5.6-C
11	Statement as to whether any adjustments have been made to balances previously approved by the OEB on a final basis If yes, explanations provided for the nature and amounts of the adjustments and supporting documentation under a section titled "Adjustments to Deferral and Variance Accounts	Section 1.5.6 page 15/30
12	GA rate riders calculated on an energy basis (kWh)	Not applicable, as DVA threshold not reached
General	Propose rate riders for recovery or refund of balances that are proposed for disposition. The default disposition period is one year; if the applicant is proposing an alternative recovery period must provide explanation.	Not applicable, as DVA threshold not reached
3.2.5.1 Wholesale Market Participants		
12	Establish separate rate riders to recover balances in the RSVA's from Market Participants who must not be allocated the RSVA balances related to charges for which the WMP's settle directly with the IESO.	N/A- no DVA disposition
3.2.5.2 Global Adjustment		
13	Establishment of a separate rate rider included in the delivery component of the bill that would apply prospectively to Non-RPP Class B customers when clearing balances from the GA Variance Account	N/A- no DVA disposition
14 & Addendum, Pages 16 - 17	For each year that the accumulated balance of Account 1589 has not been disposed, regardless of whether or not distrbutors are seeking disposition of Group 1 accounts in the current proceeding, all distributors are required to file the GA Analysis Workform in live Excel format and responses to questions in Appendix A of the GA Analysis Workform Instructions; explain discrepancies. Unexplained discrepancies calculated separately for each calendar year	No- please see Cover letter. BPI is working to complete this however th GA analysis is not requested for disposition.
14 15	Description of settlement process with IESO or host distributor, specify GA rate used for each rate class, itemize process for providing estimates and describe true-up process, details of method for estimating RPP and non-RPP consumption, treatment of embedded generation/distribution, distributor's internal control tests in validating estimated and actual consumption figures used in RPP settlement process and subsequent true-up adjustments If distributor uses the actual GA rate to bill non-RPP Class B customers, a proposal must be made to exclude these customer classes from the allocations of the balance of Account 1589 and the calculation of the resulting rate riders	Section "Commodity Accounts 1588 and 1589"- page 16/30
15	Description of financial accounting practices related to recording transaction in 1588 and 1589	Section "Commodity Accounts 1588 and 1589"- page 16/30
14 & 15	Disclosure of nature, timing, and dollar impact of subsequent adjustments recorded after recording period that adjust the initial transactions from preliminary estimates to actual figures based on consumption data - complete GA Analysis Workform for each applicable fiscal year subsequent to the most recent year in which Accounts 1588 and 1589 were approved for disposition on a final basis by the OEB	Section "variances from RRR Trial Balance" GA analysis is delayed per Cover letter.
15	If a distributor uses the actual GA price to bill non-RPP Class B customers for an entire rate class, propose made to exclude these customer classes from the allocation of the balance of account 1589 RSVA GA and the calculation of the resulting rate riders - these rate classes are not to be charged/refunded the GA rate rider as they did not contribute to the accumulation of the balance of account 1589 RSVA GA	N/A confirmed in section 1.5.6, page 16
3.2.5.3 Commodity Accounts 1588 and 1589		
15	RPP Settlement True-Up - distributors to follow guidance in May 23, 2017 letter pertaining to the period that is being requested for disposition for Accounts 1588 and 1589	N/A no disposition requested
15	Certification by the CEO, CFO or equivalent that distributor has robust processes and internal controls in place for the preparation, review, verification and oversight of account balances being proposed for disposition	IRM Attachment C
Addendum, Pages 12 - 13	Status update on implementation of new accounting guidance (related to Accounts 1588 and 1589 - Feb 21, 2019), a review of historical balances, results of the review, and any adjustments made to account balances; for any adjustments made - include the reason, how it was quantified and the journal entried to adjust the balances	Section 1.5.6, starting page 14
3.2.5.4 Capacity Based Recovery (CBR)		
16	Proposed disposition of Account 1580 sub-account CBR Class B in accordance with the OEB's CBR Accounting Guidance. - embedded distributors who are not charged CBR (therefore no balance in sub-account CBR Class B) must indicate this is the case for them - In the DVA continuity schedule, applicants must indicate whether they serve any Class A customers during the period where Account 1580 CBR Class B sub-account balance accumulated. - Account 1580 sub-account CBR Class A is not to be disposed through rates proceedings but rather follow the OEB's accounting guidance. - The DVA continuity schedule will allocate the portion of Account 1580 sub-account CBR Class B allocated to customers who transitioned between Class A and Class B based on consumption levels	No disposition requested, howeverrequired tabs are filled in correctly in IRM model
3.2.6 Lost Revenue Adjustment Mechanism Variance Account		
Addendum, Pages 20 - 22	LRAMVA - disposition of balance. Distributors must provide version 4 of LRAMVA Work Form in a working Excel file when making LRAMVA requests for remaining amounts related to CFF activity. An application for lost revenues should include: Participation and Cost reports in Excel format, made available by the IESO. An application for lost revenues should also provide the following: - statement identifying the year(s) of new lost revenues and prior year savings persistence claimed in the LRAMVA disposition - statement confirming LRAMVA based on verified savings results supported by the distributors final CDM Report and Persistence Savings Report (both filed in Excel format) and a statement indicating use of most recent input assumptions when calculating lost revenue - summary table with principal and carrying charges by rate class and resulting rate riders - statement providing the disposition period; rationale provided for disposing the balance in the LRAMVA if one or more classes do not generate significant rate riders - statement confirming LRAMVA reference amounts, rationale for the distributors circumstances if LRAMVA threshold not used - rationale confirming how rate class allocations for actual CDM savings were determined by class and program (Tab 3-A of LRAMVA Work Form) - statement confirming whether additional documentation was provided in support of projects that were not included in distributors final CDM Annual Report (Tab 8 of LRAMVA Work Form as applicable) - for a distributor's streetlighting project(s) which may have been completed in collaboration with local municipalities, the following must be provided: Explanation of the methodology to calculate streetlighting savings; Confirmation whether the streetlighting savings were calculated in accordance with OEB-approved load profiles for streetlighting projects; Confirmation whether the streetlighting project(s) received funding from the IESO and the appropriate net-to-gross assumption used to calculate streetlighting savings For the recovery of lost revenues related to demand savings from street light upgrades, distributors should provide the following information: o Explanation of the forecast demand savings from street lights, including assumptions built into the load forecast from the last CoS application o Confirmation that the street light upgrades represent incremental savings attributable to participation in the IESO program, and that any savings not attributable to the IESO program have been removed (for example, other upgrades under normal asset management plans) o Confirmation that the associated energy savings from the applicable IESO program have been removed from the LRAMVA workform so as not to double count savings (for example, if requesting lost revenue recovery for the demand savings from a street light upgrade program, the associated energy savings from the Retrofit program have been subtracted from the Retrofit total)	Not seeking disposition
3.2.7 Tax Changes		
19 & 20	If applicable, tabs 8 and 9 of Rate Generator Model complete	N/A- Section1.5.8
20	If one or more customer classes does not generate a rate rider to the fourth decimal place, a proposal that the entire 50/50 sharing amount will be transferred to Account 1595 for disposition at a future date	N/A- Section1.5.8
3.2.8 Z-Factor Claims, Pg. 20-21		
20	Evidence that costs incurred meet criteria of need, materiality and prudence - see 3rd Generation IRM Report	N/A not claimed Section 1.5.9

2020 IRM Checklist
Brantford Power Inc.
EB-2019-0022

Filing Requirement Page # Reference

Date: August 12, 2019

Filing Requirement Page # Reference		Evidence Reference, Notes
IRM REQUIREMENTS		
20 & 21	In addition distributor must: - Notify OEB by letter of all Z-Factor events within 6 months of event (Confirm that letter is on file) - Apply to OEB for any cost recovery of amounts in OEB-approved deferral account claimed under Z-Factor treatment - Demonstrate that distributor could not have been able to plan or budget for the event and harm caused is genuinely incremental - Demonstrate that costs incurred within a 12-month period and are incremental to those already being recovered in rates as part of ongoing business exposure risk	N/A not claimed Section 1.5.9
3.2.8.2 Z-Factor Accounting Treatment		
21	Eligible Z-factor cost amounts recorded in Account 1572, Extraordinary Event Costs, of the OEB's USoA contained in the Accounting Procedures Handbook (APH) for electricity distributors.	N/A not claimed Section 1.5.9
21	Carrying charges are calculated using simple interest applied to the monthly opening balances in the account and recorded in a separate Sub-Account of this account	N/A not claimed Section 1.5.9
3.2.8.3 Recovery of Z-Factor Costs		
21	Description of manner in which distributor intends to allocate incremental costs, including rationale for approach and merits of alternative allocation methods	N/A not claimed Section 1.5.9
21	Specification of whether rate rider(s) will apply on fixed or variable basis, or combination; length of disposition period and rational for proposal	N/A not claimed Section 1.5.9
21	Residential rider on fixed basis	N/A not claimed Section 1.5.9
21	Detailed calculation of incremental revenue requirement and resulting rate rider(s)	N/A not claimed Section 1.5.9
3.3.1 Advanced Capital Module, Pg. 22-23		
22	Evidence of passing "Means Test"	N/A see section 1.5.10
22	Information on relevant project or projects updated cost projections, confirmation that the project or projects are on schedule to be completed as planned and an updated ACM/ICM module in Excel format	N/A see section 1.5.10
22/23	If proposed recovery differs significantly from pre-approved amount, a detailed explanation is required as to why	N/A see section 1.5.10
23	If updated cost projects are 30% greater than pre-approved amount, distributor must treat project as new ICM, re-filed business case and other relevant material required	N/A see section 1.5.10
3.3.2 Incremental Capital Module, Pg. 23-29		
3.3.2.1 ICM Filing Requirements		
	The following should be provided when filing for incremental capital:	
25	An analysis demonstrating that the materiality threshold test has been met and that the amounts will have a significant influence on the operation of the distributor	ICM Section 1.2.5
25	Justification that the amounts to be incurred will be prudent - amounts represents the most cost-effective option (but not necessarily the least initial cost) for ratepayers	ICM Section 1.2.8
25	Justification that amounts being sought are directly related to the cause, which must be clearly outside of the base upon which current rates were derived	ICM Section 2.8
25	Evidence that the incremental revenue requested will not be recovered through other means (e.g., it is not, in full or in part, included in base rates or being funded by the expansion of service to include new customers and other load growth)	ICM Section 1.0, Section 2.8
25	Details by project for the proposed capital spending plan for the expected in-service year	ICM Section 2.0
25	Description of the proposed capital projects and expected in-service dates	ICM Section 2.0 and 2.10
25	Calculation of the revenue requirement (i.e. the cost of capital, depreciation, and PILs) associated with each proposed incremental capital project	ICM Table 1; ICM model
25	Calculation of each incremental project's revenue requirements that will be offset by revenue generated through other means (e.g. customer contributions in aid of construction)	ICM Section 2.8- Reduction for severable land; allocations to parties
25	Description of the actions the distributor would take in the event that the OEB does not approve the application	ICM Section 1.2.7
25	Calculation of a rate rider to recover the incremental revenue from each applicable customer class. The distributor must identify and provide a rationale for its proposed rider design, whether variable, fixed or a combination of fixed and variable riders. As discussed at section 3.2.3, any new rate rider for the residential class must be applied on a fixed basis	ICM Section 1.1
3.3.5 Off-Ramps		
30	A distributor whose earnings are in excess of the dead band (i.e. 300 basis points) but nevertheless applies for an increase to its base rates - an explanation to substantiate its reasons for doing so required	N/A
Appendix A		
Appendix A	Confirm disposition of residual balances for vintage Account 1595 have only been done once - distributors expected to seek disposition of the balance a year after a rate rider's sunset date has expired. No further dispositions of these accounts are generally expected unless justified by the distributor	N/a- no 1595 disposition requested
Appendix A & Addendum, Page 22	Distributors who meet the requirements for disposition of residual balances of Account 1595 sub-accounts, must complete the 1595 Analysis Workform. Account 1595 sub-accounts are eligible for disposition when one full year has elapsed since the associated rate riders' sunset dates have expired and the residual balances have been externally audited.	No disposition however work form included as Att I
Appendix A	Material residual balances will require further analysis, consisting of separating the components of the residual balances by each applicable rate rider and by customer rate class. Distributors are expected to provide detailed explanations for any significant residual balances attributable to specific rate riders for each customer rate class. Explanations must include for example, volume differences between forecast volumes (used to calculate the rate riders) as compared to actual volumes at which the rate riders were billed.	N/A -no disposition, limited residual balance.