BRANTFORD power
Your delivery company

September 9, 2016

Ms. Kirsten Walli
Ontario Energy Board
PO Box 2319 27th Floor,
2300 Yonge Street
Toronto, Ontario
M4P 1E4

Dear Ms. Walli,

Re: 2017 COS Rates Application, Interrogatory Responses Board File No.: EB-2016-0058

Pursuant to Procedural Order No. 1 in the above noted matter, please find enclosed the Brantford Power Inc. ("BPI") interrogatory responses to Board Staff, Energy Probe ("EP"), School Energy Coalition ("SEC") and Vulnerable Energy Consumers Coalition ("VECC"). Further, BPI has updated several models and has submitted them in Live Excel format.

If you have any further questions, please do not hesitate to contact me at (519) 751-3522 Ext 5133 or via email at bdamboise@brantford.ca.

Sincerely,

[Original Signed By]

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cc: Randy Aiken, Aiken & Associates
Bruce Bacon, Borden Ladner Gervais
Michael Janigan, VECC Counsel
Paul Kwasnik, Brantford Power Inc.
David MacIntosh, Energy Probe
Wayne McNally, SEC Coordinator
Martha McOuat, Ontario Energy Board
Mark Rubenstein, Jay Shepherd Professional Corporation
Jay Shepherd, Jay Shepherd Professional Corporation
James Sidlofsky, Borden Ladner Gervais

Brantford Power Inc.

Cost of Service Rate Application for Rates Effective January 1, 2017

Interrogatory Responses

EB-2016-0058

Filed: September 9, 2016

Contents

Exhibit 1: Administration

IR: 1-Staff-1

a) Please provide an update to capital, OM&A, cost of power, load forecast and revenue requirement to incorporate at least six months of actual data for 2016 in the bridge year.

b) Upon completing all interrogatories from OEB staff and intervenors, please provide an updated RRWF in working Microsoft Excel format with any corrections or adjustments that Brantford Power wishes to make to the amounts in the previous version of the RRWF included in the middle column. Entries for changes and adjustments should be included in the middle column on sheet 3 Data_Input_Sheet. Please include documentation of the corrections and adjustments in the final sheet of the model, such as a reference to an interrogatory response or an explanatory note.

Response:

Please find the attached models updated for 2016 actuals only. BPI has consulted 2016 June YTD actuals and made adjustments in the following areas based on the YTD Trending:

- Cost of Power Model
- Load Forecast- updated regression for 6 month of 2016 actual
- Updates to CDM for 2015 actual CDM results and updated 2016/2017 forecast
- Revenue Offsets-
- Remove request for building funding in 2016

IR: 1-Staff-2

Ref: Appendix 2-W, Bill Impacts

Upon completing all interrogatories from OEB staff and intervenors, please provide updated bill impacts for all classes at the typical consumption / demand levels (e.g. 750 kWh for residential, 2,000 kWh for GS<50, etc.), reflecting any changes made during the interrogatory process.

Response:

Please see updated bill impacts submitted with Appendix 2 updates under 1-Staff-1.

IR: 1-Staff-3

Ref: Responses to Letters of Comment

Following publication of the Notice of Application, the OEB received 1 letter of comment. Sections 2.1.9 of the Filing Requirements states that distributors will be expected to file with the OEB their response to the matters raised within any letters of comment sent to the OEB related to the distributor's application. If the applicant has not received a copy of the letters, they may be accessed from the public record for this proceeding.

Please file a response to any matters raised in the letter of comment referenced above. Going forward, please ensure that responses are filed to any subsequent matters that may be raised in any further letters filed in this proceeding. All responses must be filed before the argument (submission) phase of this proceeding.

Response:

As shown in the Application and evidence, BPI has actively engaged with its customers, and is aware of the challenges faced by many vulnerable energy consumers. BPI is sensitive to the issue of energy affordability and is working to address the issue of electricity bill affordability in the following ways:

- Ongoing engagement with customers including opportunities to educate customers with respect to the energy system;
- The provision of Conservation and Demand Management Programs to assist any interested customer to lower their consumption, lowering their bills;
- Partnering with the Family Counseling Centre of Brant to provide the Ontario Electricity Support Program for ongoing, on-bill financial support for qualifying consumers; and
- Providing emergency financial assistance through the Family Counseling Centre of Brant to provide emergency financial assistance through the Low-Income Energy Assistance Program ("LEAP").
- Specific to this Application, in its budgeting BPI has taken the customer impact into consideration. BPI must balance the investments needed to operate and maintain its distribution system with the cost impact of these investments to customers.

- Additionally, BPI has made adjustments, for example the rate base and OM&A reductions associated with the building (in the original Application), as well as the amortization of System Integration Project OM&A during the Cost of Service cycle, in the favour of the customer, to consider customer affordability.

IR: 1-Staff-4

Ref: Conditions of Service

a) Please identify any rates and charges that are included in the Applicant's Conditions of Service, but do not appear on the OEB-approved tariff sheet, and provide an explanation for the nature of the costs being recovered through these rates and charges.
b) Please provide a schedule outlining the revenues recovered from these rates and charges from 2012 to 2014 inclusive, and the revenues forecasted for the 2015 bridge and 2016 test years.
c) Please explain whether, in the Applicant's view, these rates and charges should be included on the Applicant's tariff sheet of approved rates and charges.

Response:

a) BPI does not have any rates and charges in the Conditions of Service that do not appear on the OEB-approved tariff sheet. Included in our Conditions of Service are billable work orders that are based on time and material charges. BPI does not consider these to be rates and charges

b) BPI does not have any rates and charges in the Conditions of Service that are not on the Tariff of Rates and Charges and therefore no revenues with respect to such to report.

c) BPI does not have any rates and charges in the Conditions of Service that are not on the Tariff sheet.

IR: 1-Staff-5

Ref: Exhibit 1, Tab 1, Schedule 3, pg. 2

In its overview of the budget process methodology, Brantford Power has identified a specific requirement incorporating a review of alternative approaches to service delivery and the annualization of productivity savings achieved.

a) Please provide an itemized list of the productivity initiatives and resulting savings identified for 2015 during the preparation of the 2017 test year budget.
b) Please describe how these productivity savings were incorporated into the 2017 budget.

Response:

a) As indicated in the budget process methodology referenced above, the requirement to consider alternative approaches to service delivery and the reflection of the annualization of productivity savings achieved have been included in the budget process so BPI leaders can, where applicable, incorporate these factors when preparing their budget submissions.

As BPI requires the use of the "clean slate framework" whereby the next year's budget does not automatically carry forward the approved budget from the previous year, the current budget process does not require the leaders to roll forward on a line by line basis the prior year's budget or previous year's projections to the new request as part of their submissions. The Budget Year requirements are expected to represent the net requirements for the year including inflationary increases, the impact of workload volume increases or decreases related to regular work or special projects and the cost to implement and any resulting savings related from productivity initiatives.

In addition, because of functionality limitations of the current financial information system, limited documentation exists to allow Brantford to extract specific reasons for any budgetary differences from one year to the next without significant manual data gathering and analysis.
Nevertheless, Brantford has used best efforts to compile from available records a listing of productivity initiatives and resulting savings as requested which have been outlined in the following table:

Name of Productivity Measure	Description	Savings	Reflected in 2017 Budget?
Outsource Bill Printing	•more productive use of staff time. • decreasese in postage and mailing costs; • Savings related to asset maintenance and avoiding asset replacement (bill inserter machine) •enables the provision of additional services in the form of e-billing, an identified customer preference	20,000 in e-billing postage savings (2017); 14,000 in avoided asset maintenance; 25,000 in re-purposed staff time.	Savings for postage built in related to an assumed 5% takeup of e-billing, asset maintenance not included in budget.
Manager of Regulatory not filled; Senior Analyst.	BPI did not fill the Manager of Regulatory role when it became vacant. A Senior Regulatory Analyst role was created.	$10,000	Senior Regulatory Analyst is reflected in Regulatory Budget but not Manager of Regulatory.

b) Where productivity savings have been identified as part of the budget process, part year savings achieved in the previous year would be annualized and reflected as a full year saving when applicable in the budget year. New anticipated savings in the budget year would be recognized in that budget for the part year representing the period they are expected to be achieved and annualized thereafter as applicable in subsequent years.

Similarly, productivity initiative evaluation and implementation costs would also be updated in the budget year by adding or removing the full or part year costs related to the initiative as initiatives are completed and new ones are initiated.

Please see the third column in the response to part (a) for a description of how each specific savings measure was carried through.

IR: 1-Staff-6

Ref: Exhibit 1, Attachment 1-F

In the 2015 reconciliation between the audited financial statements and the RRR, there is a reconciling item of $136k impairment loss that was due from affiliates on Brantford Power's audited financial statements but reclassified to expenses in the RRR. Please explain what this impairment loss pertains to, how impairment was determined and what the impact to Brantford Power's application was.

Response:

BPI recorded an impairment loss of $136,261 related to the receivable balance from its affiliate, Brantford Generation Inc. ("BGI"), which is currently in financial distress and is proceeding with a financial restructuring. The impairment loss represents 100% of the carrying value. The amount was reclassified to expense account 4380 – Non-Utility Expenses for the purposes of RRR.

The impairment loss is related to executive and finance services provided to BGI from BPI, which are non-utility expenses. Although the non-payment by BGI represents a bad debt to BPI, BPI made the adjustment to ensure that the impairment was not included in the calculation of distribution OM&A to ensure that OM&A only reflected bad debts from customer non- payment for distributions services.

Since the adjustments relate to 2015 and 2016, and not the 2017 Test Year, there is no impact to the revenue requirement being sought for recovery associated with this component of bad debt. BPI does not anticipate there will be any time spent on BGI matters during 2017, and therefore there are no equivalent expenses or bad debts expected.

IR: 1-Energy Probe-1

Ref: Exhibit 1, Tab 2, Schedule 7

How was the rate of 4.20% on the affiliate debt that was renewed on Feb. 1, 2016 determined to be a competitive rate? Did BPI seek any debt from third parties in the same timeframe?

Response:

BPI renewed the rate on its note with the City of Brantford based on terms of the promissory note, which is RBC Prime + 1.5%.

BPI compared the stipulated five year renewal rate contained in the promissory note against the OEB's deemed long term debt rate and the publicly available 30 year rate available from Infrastructure Ontario in December 2015.

Brantford Power Inc.

Illustration of Alternative Financing Rates

Source	Current Rate
Promissory Note Renewal Rate (Prime + 1.5%)	4.20%
Ontario Energy Board Deemed Long Term Debt Rate	4.54%
Infrastructure Ontario Long Term Debt Rate (30 year Term – Dec 3)	3.89%

Infrastructure Ontario had advised BPI that it would not be eligible for any new financing until such time Infrastructure Ontario and Brantford Generation Inc. (affiliate of BPI) had resolved their issues. In effect, this lower rate was not available to BPI at the time of renewal.

Consequently, BPI proceeded with the 4.20% as the lowest cost alternative.

BPI did not seek any debt from third parties in the same time frame for the following reasons:

- The existing City of Brantford promissory note is currently subordinated to both the Royal Bank and Infrastructure Ontario Long Term Debt. The introduction of a third lender at this time would have required a renegotiation of the relative security position of existing lenders. With the pending new financing required to fund the planned acquisition of a single facility to replace the existing three BPI operating locations, BPI believed it was prudent to continue to retain the City of Brantford's promissory note because its current subordinated position provides BPI with the most flexibility to secure new financing for the pending facility acquisition.
- Furthermore, as BPI's current lending covenants with Infrastructure Ontario requires Infrastructure Ontario to approve any new borrowings, the refinancing of existing debt would likely dilute their current security interests as it is unlikely a third lender would accept a third place security position without requiring a higher interest rate. BPI believed it had a better opportunity to obtain the consent of Infrastructure Ontario for new borrowings in the context of financing the acquisition of its planned facility as this would result in additional assets in the security pool commensurate with the financing obtained which could be ring fenced and avoid impacting the security position of existing lenders.

IR: 1-Energy Probe-2

Ref: Exhibit 1, Tab 4, Schedule 8

The evidence states that BPI applies fully allocated costing to the provision of services to its affiliates and that the costs exactly match the revenues.

a) Please confirm that all of the costs are included in account 4380 and that there are no costs included in the OM&A associated with the provision of services to affiliates in either the test year, bridge year or in any of the historical years. If this cannot be confirmed, please explain fully.

b) Please confirm that the fully allocated costs include both direct and indirect costs, such as a percentage of building rate base and operating/maintenance expenses, a percentage of computer and software capital costs and operating/maintenance expenses and the associated depreciation costs. If this cannot be confirmed, please explain why these costs are not fully allocated to the provision of services to the affiliates.

Response:

a) BPI confirms there are no OM&A costs included with the provision of services to affiliates in the Bridge, Test and Historic years. BPI employees who perform work for affiliates docket the time spent on affiliate matters. A proportional component of their salary, wages and other fully allocated OM&A costs are billed to the appropriate affiliates. The expenses and revenues are recorded in accounts 4380 and 4375 in order to isolate them from impacting distribution OM&A.

b) For historic costs, BPI has included fully allocated costing, which includes allocations of the home business units for each employee. For Bridge Year and Test Year forecasts, no amounts related to FIS capital (return on capital, depreciation and tax) has been included in these calculations. BPI acknowledges that the affiliate recoveries need to reflect this amount, and is in the process of estimating the 2016 and 2017 amounts which need to be charged, both related directly to affiliate users and the fully allocated capital cost for BPI employees performing work for the affiliates. Given the comparative simplicity of affiliates operations and the relative small number of affiliate users, BPI does not expect these amounts to be material.

IR: 1-Energy Probe-3

Ref: Exhibit 1, Tab 5, Schedule 1

The evidence states that for 2014 there were no material changes from the transition to MIFRS from CGAAP.

a) Does this statement also apply to only the impact on OM&A?

b) What is the approximate impact on 2013 OM&A of the change from CGAAP to MIFRS?

Response:

a) The reference at Exhibit 1, tab 5, schedule 1 refers to the revenue requirement impact of MIFRS. BPI would like to correct the record to add $100,000 in 2017 additional expenses, related to the amortization increase associated with the early retirement of assets, so the revenue requirement impact in 1.5-A should be $99,429. For the 2014 transition year, BPI confirms that the MIFRS impact on OM&A and the MIFRS increase on revenue requirement were not material.

b) The 2013 impact to OM&A only would be approximately $18,400. This is the impact of a decrease related to $31,600 in prepaid expenses, offset by an increase of about $50,000 related to Other Post Employment Benefits (assuming the OPEBs impact is about the same level as for 2014).

   BPI notes this was an approximate answer only. BPI notes the early disposals are recorded as amortization expense, and therefore have not been included in the figures above.

IR: 1-Energy Probe-4

Ref: **Exhibit 1, Tab 2, Schedule 10 &**

Exhibit 1, Tab 7, Schedule 8

Please explain the different level of bill impacts shown in Table 1.2.10 and Table 1.7.8.

Response:

The table shown in 1.2.10 represents total bill impacts while the table shown in 1.7.8 only shows bill impacts from changes in distribution excluding pass-through costs (sub-total A).

Please refer to the table below which is an extract from Appendix 2-W. Column A are the amounts referred to in the table shown in 1.7.8 and the Total column on the far right are the amounts referred to in the table shown in 1.2.10.

Table 2

RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	Units	Sub-Total						Total	
		A		B		C		A + B + C	
		$	%	$	%	$	%	$	%
Residential	kWh	$ 4.12	17.2%	$ 1.88	7.1%	$ 1.85	5.0%	$ 2.08	1.5%
Residential	kWh	$ 5.16	27.6%	$ 4.44	22.0%	$ 4.42	18.3%	$ 4.99	8.1%
Residential	kWh	$ 3.77	13.8%	$ 1.41	4.8%	$ 1.38	3.4%	$ 1.54	0.9%
General Service Less than 50 kW	kWh	$ 8.66	18.2%	$ 2.67	5.0%	$ 2.60	3.3%	$ 2.90	0.9%
General Service Less than 50 kW	kWh	$ 10.86	19.9%	$ 1.87	3.0%	$ 1.77	1.8%	$ 1.94	0.4%
General Service 50-4,999 kW	kW	$ 443.46	25.1%	-$ 131.05	-5.9%	-$ 131.25	-3.1%	-$ 209.34	-0.8%
Street Lighting	kW	$ 3.71	103.4%	$ 2.59	41.8%	$ 2.59	25.5%	$ 2.92	6.2%
Sentinal Lighting	kW	$ 4.19	17.8%	$ 3.19	12.7%	$ 3.19	11.0%	$ 3.60	4.9%
Embedded Distributor	kW	$ 3,930.30	55.2%	$ 2,852.30	34.7%	$ 2,850.70	11.4%	$ 2,775.95	1.5%
Unmetered Scatter Load	kWh	$ 2.65	17.7%	$ 1.80	10.9%	$ 0.96	4.8%	$ 1.08	1.9%

IR: 1-Energy Probe-5

Ref: Exhibit 1, Tab 8, Schedule 1

a) Please provide live Excel spreadsheets of the PEG benchmarking tool used by BPI to arrive at the figures shown in Table 1.8-B.

b) Please explain why some figures are missing for actual 2014 in Table 1.8-B.

c) Please update the table to include actual 2015 data.

Response:

a) Please refer to Attachment 1-EP-5 for the live Excel spreadsheet of the PEG benchmarking tool used by BPI to arrive at the figures shown in Table 1.8-B.

b) Please refer to the following updated chart which includes the missing information for actual 2014.

Year		Total Cost	Cost per Customer	Cost per km of Line	% difference from Predicted	3 Year Average Performance	Efficiency Assessment
2013	Actual	$ 19,528,936	$ 507.00	$ 39,373	0.71%	0.97%	3
2014	Actual	$ 19,239,301	$ 503.00	$ 39,047	-4.14%	0.42%	3
2015	Actual	$ 19,730,181	$ 504.25	$ 39,619	-6.83%	-3.42%	3
2013	Modelled	$ 19,391,353	$ 506.64	$ 39,373	0.71%	0.97%	3
2014	Modelled	$ 20,052,029	$ 495.96	$ 38,595	-4.14%	0.42%	3
2015	Modelled	$ 21,124,973	$ 502.59	$ 39,488	-6.83%	-3.42%	3
2016	Modelled	$ 22,181,005	$ 589.79	$ 46,387	4.56%	-2.24%	3
2017	Modelled	$ 23,345,342	$ 576.71	$ 45,594	-1.78%	-1.46%	3
2018	Modelled	$ 24,615,173	$ 580.66	$ 46,136	-5.39%	-0.87%	3
2019	Modelled	$ 26,012,218	$ 585.46	$ 46,751	-9.09%	-5.42%	3

c) Please refer to the chart in b) above which has been updated to include actual 2015 data.

IR: 1-Energy Probe-6

Ref: Exhibit 1, Tab 9, Schedule 1

a) Please explain how the salary, wages and benefits associated with the Vice President responsible for customer service, communications and conservation and demand management departments have been split between the utility related functions and the CDM department function.

b) Has BPI included all of the costs associated with this new position in the BPI revenue requirement?

c) Has BPI determined the amount of the costs associated with the CEO that should be included in the regulated revenue requirement, given the additional responsibilities taken on related to the affiliates?

Response:

a) The VP Customer Service and CDM books her time to the CDM business unit for any work done related to CDM. Costs related to wages and benefits, as well as other related expenses (payroll burden, office supplies, etc.) are then allocated to CDM accordingly throughout the year.

For budgeting purposes, the expected hours spent on CDM work for the VP Customer Service and CDM is forecasted, based on trends in past year and the expected workload for the coming years. This forecast is then used to allocate a proportionate amount of salaries, benefits and other related expenses to the CDM business unit.

As the result of a budgeting error, the time allocated with the CDM work forecast for this position was not carried through to the 2016 and 2017 budget. BPI has made an adjustment to correct this in 2017 as part of its response to 1-Staff-1 b), removing the associated costs of $6,061 from OM&A and moving it into 4380 Non-Utility Expenses, as well as adding offsetting revenue of $6,061 in 4375-Non Utility Revenue.

b) As discussed above, while the full cost of the position had been included (erroneously) in the revenue requirement, the updates made in 1-Staff-1 b) include a correction.

c) Yes, through a process similar to the one described above for the VP CS ad CDM, the CEO dockets time spent doing work for affiliates. The affiliates are charged a proportionate amount of CEO expenses (including wages, benefits and other expenses) based on this time docketing. For 2017, roughly 17% is allocated to the affiliates for CEO time, based on forecasts of the time requirements for each affiliate. The revenues and expenses associated with executives' services to the affiliates have been included in accounts 4375 and 4380 and net to $0 in order to exclude these costs from the revenue requirement.

IR: 1-Energy Probe-7

Ref: Exhibit 1, Tab 9, Schedule 1

Does the position of executive assistant only perform work for BPI or does the position also assist the CEO with his role in the affiliates? If the latter, please explain how the costs associated with this position have been allocated between the regulated BPI and the unregulated affiliates.

Response:

The position of Executive Assistant to the CEO also performs work to assist with the affiliates. The Executive Assistant dockets time in the same manner as the CEO, CFO, and Finance staff docket the time they spend on affiliate work. The expenses including wages, benefits, burden and office expense, are billed proportionately to affiliates based on the amount of time spent on affiliate work. The associated expenses and revenues are recorded in the revenue offset accounts 4375 and 4380 in order to exclude these from the calculation of revenue requirement. For 2017, approximately 11% of these expenses are allocated to affiliates.

IR: 1-Energy Probe-8

Ref: Exhibit 1, Tab 9, Schedule 2

a) Please confirm that there are no costs included in the historical, bridge or test year OM&A figures associated with the cost of the Board of Directors of Brantford Energy. If this cannot be confirmed, please provide the costs included in the OM&A costs both historically and forecast for the bridge and test years that have been included in the BPI OM&A figures.

b) Are there any costs related to Brantford Energy that have been included in the BPI revenue requirement? If yes, please provide a description of the costs and quantification of the costs from 2013 through 2017.

Response:

a) OM&A does not include the cost of the BEC Board of Directors and BPI costs only reflect the costs for BPI's Board of Directors.

b) There are no costs related to Brantford Energy included in the BPI revenue requirement.

IR: 1-SEC-1

[Ex.1-1-2, p.2-3]
With respect to the Applicant's strategic goals, please:

a. Provide a copy of the latest Strategic Plan.
b. Explain how the strategic goal to "[g]row the business…." furthers each of the RRFE outcomes.
c. Please explain what the Applicant means by growing the business by directing capital <u>to industry levels.</u>

Response:

a. Copy attached

   Attachment 1-SEC-1: Copy of BPI Strategic Plan

b. The strategic goal "Grow the business by directing capital to industry levels by increasing our systems, facilities, technology, customer base and infrastructure" furthers each of the RRFE Outcomes as follows:

   As a result of BPI's former "virtual" utility structure, certain elements of General Plant typically used by an LDC such as facilities and information systems were purchased and owned by the City of Brantford and not reflected in BPI's rate base. As a result, BPI's Property Plant and Equipment per customer was not in keeping with other LDCs of comparable size because these asset classes were not represented.

   Following BPI's restructuring in 2012 where the "virtual" utility structure was replaced with a more conventional utility structure where LDC functions are performed by LDC employees, BPI had the opportunity to consider only the specific requirements for BPI when assets required replacement instead of pursuing with the City of Brantford, General Plant additions that included specifications that provided for a hybrid solution addressing the requirements for municipal administration and the requirements for an LDC.

   As part of prudent procurement of these assets at the time of replacement, BPI can now develop specifications that solely address its business needs and the needs of its customers. In this manner, BPI is expected to reflect new investments in the General Plant component as it acquires for the first time, assets that are in general use by LDCs to replace existing shared assets. This will occur over time in keeping with the Distribution System Plan forecasts. As the elements of Property Plant and Equipment are acquired over time, BPI expects that over a period of time, its PPE per customer will eventually be in keeping with the levels currently in place for other comparable LDCs.

RRFE Outcome	1) How "Grow the Business…" furthers the RRFE Outcomes
Customer Focus	• The ability of operating under one facility will improve cross departmental communications allowing for more timely and effective responses to customers and provide a single site to conduct business with BPI. • Investment in new FIS will provide opportunities for better cost tracking for better and timely exception identification of exceptions for improved project management and possible resulting efficiencies. • Investment in new CIS and OMS will provide features customers have been requesting that current systems are not capable of e.g. web presentment, self-serve options, better and more timely outage information. • Investments in systems generally are expected to increase the level of service to the levels in keeping with good utility practice that are not possible with BPI's existing antiquated systems. • Expansion in customer base will allow for amortization of fixed costs over a larger base potentially reducing the per customer contribution to these costs. • Continued investments in technology and infrastructure in keeping with sound asset management principles will ensure BPI maintains or improves reliability levels for customers;
Operational Effectiveness	• The ability of operating under one facility will improve cross departmental communications allowing for more timely and effective management and administration of the business. Some efficiency opportunities are possible with respect to duplicated space and equipment when operating in three facilities including the elimination of travel time between locations. • Investment in new FIS will provide opportunities for better cost tracking for better and timely exception identification of exceptions for improved project management and possible resulting efficiencies. In addition FIS is expected to streamline or automate some of the existing cumbersome or manual business processes and improve integration between other BPI systems for more timely management information and reduce duplication. Also with more timely information, the ability for timely corrective action to remedy exceptions will be enhanced. • Investment in new CIS will provide more timely and additional integration into the GIS and FIS systems. In addition CIS is expected to

RRFE Outcome	1) How "Grow the Business…" furthers the RRFE Outcomes
	streamline or automate some of the existing cumbersome or manual business processes. • Expansion in customer base will allow for amortization of fixed costs over a larger base potentially reducing the per customer cost of OM&A. • Continued investments in technology and infrastructure in keeping with sound asset management principles will ensure BPI maintains its infrastructure in proper working order and minimize repair costs.
Public Policy Responsiveness	• Investment in new FIS will provide opportunities for better cost tracking and flexibility in meeting existing and adapting to changing reporting obligations • Investment in new CIS will provide more system capability to more effectively introduce mandated changes to billing and settlement requirements. • Continued investments in technology and infrastructure in keeping with sound asset management principles will ensure BPI maintains its infrastructure in proper working order to meet the performance obligations established by the OEB and reported on the scorecard.
Financial Performance	• The ability of operating under one facility will improve cross departmental communications allowing for more timely and effective management and administration of the business. Some efficiency opportunities are possible with respect to duplicated space and equipment when operating in three facilities including the elimination of travel time between locations. • Investment in new FIS will provide opportunities for better cost tracking for better and timely exception identification of exceptions for improved project management and possible resulting efficiencies. In addition FIS is expected to streamline or automate some of the existing cumbersome or manual business processes and improve integration between other BPI systems for more timely management information and reduce duplication. This will either provide savings or allow existing resources the opportunity to analyze and investigate data for further improvement opportunities. • In addition CIS is expected to streamline or automate some of the existing cumbersome or manual business processes and provide more opportunities for customer self service opportunities.

RRFE Outcome	1) How "Grow the Business…" furthers the RRFE Outcomes
	• Expansion in customer base will allow for amortization of fixed costs over a larger base potentially reducing the per customer cost of OM&A. • Continued investments in technology and infrastructure in keeping with sound asset management principles will ensure BPI maintains its infrastructure in proper working order and minimize repair costs. • All of the above will provide better opportunities for efficiencies. Should they result in better cost performance than comparators, a reduced productivity stretch factor could improve financial performance.

It is important to note as described in Exhibit 1, Tab E1. Schedule 3 Page 4 of 5 where BPI described its Key Budget Considerations that it considers in addition to general strategic and business objectives the specific RRFE objectives. Although the "Grow the Business" strategic objective provides opportunities for improving shareholder returns, BPI's focus is to ensure the outcomes from such investments can contribute where possible positively to the interest of all stakeholders.

These decisions are intended to be in keeping with sound asset management principles or with utility best practices while balancing the considerations to ensure where possible that there are commensurate benefits to the customers in the form of possible cost efficiencies or the provision of requested or improved service levels. In other cases, these investments are being made to ensure BPI can continue to meet its compliance obligations which have been established for the benefit or protection of customers.

c. BPI's past capital investments have been primarily made in the distribution plant. As regular investments in certain categories of general plant have not been made with the same regularity, it has resulted in BPI having very old information systems which have higher inherent operational risk, are not conducive to optimal automation or integration with other systems and cannot provide customers with the level of e-services required.

Similarly, as BPI operates from three distinct leased facilities, BPI has been limited by the nature of those facilities to only making very minor leasehold improvements. As a result, current facilities do not allow for the realignment or expansion or contraction of space to mirror departmental groupings. This has resulted in some cases where single departments were not able to share the same work space or space was not sufficient to provided adequate access to meeting rooms.

Given the fact that BPI's property plant and equipment per customer is below those invested in many comparable LDCs, the reference to "growing the business by directing capital to industry levels" is intended to reflect that BPI's Distribution System Plan has identified the necessary investments required and the rationale for making targeted investments in all asset categories including the general plant category of Property Plant and Equipment.

Although these investments are being planned to address specific operational issues and to mitigate business risk on critical systems, they are expected to allow BPI to begin to move over time its investment per customer levels to a level more in keeping with current industry levels.

It is not BPI's objective to make investments for investment sake but rather to ensure through sound investment planning as outlined in the Distribution System Plan, that BPI target capital investments in asset classes where deficiencies exist that must be addressed to move to and ultimately achieve a vintage and capability for its property plant and equipment commensurate with good utility practice.

IR: 1-SEC-2

[Ex.1-1-3, p.4]
Please provide a copy of the latest Business Plan.

Response:

BPI's Business Plan is reflected in the Budget and Multi-Year Forecast approved by the Board at their December 2015 Board meeting.

Attachment 1-SEC-2 A BPI 2016 2017 Budget

Attachment 1-SEC-2 B 2016 Budget

Attachment 1-SEC-2 C BPI Budget Resolution.

IR: 1-SEC-3

[Ex.1-2-3, p.4]
Please provide details about what changes the SLT made after reviewing departmental budgets after "comparing it to the general inflation rate and the customer's ability to pay".

Response:

BPI's budget process involves many review steps from the department initial preparation leading to the final budget presented to the Board of Directors. The SLT review process is informal and involves a number of meetings to discuss issues and opportunities. Included in the SLT's review objectives are the following goals:

1. Obtaining an understanding and rationale for the budget proposal submitted by a department;
2. Determining the desirability and reasonability of the proposal in terms of strategic direction, business priorities or customer expectations ;
3. Determining the affordability and sustainability of the proposal i.e. can BPI afford within available funding the requests and how will this request impact the future cost of service to the customer.

SLT review will start from a bottom up approach to ensure each submission has merit. At that point, SLT will determine if the overall business plan can accommodate the sum of accepted requests. At that point, SLT will adjust requirements by deferring projects, phasing projects, changing the scope of projects or removing them from the plan to ensure spending is commensurate with available funding.

As formal change logs were not compiled as part of the budget preparation process, BPI has attempted to recreate the specific issues and changes requested during the various SLT sessions from available documentation as outlined below. Regrettably, as the budget process is iterative and changes are made as decisions are made or as analysis and quality assurance is performed, it is not possible to reproduce a full reconciliation of changes that were made from the original department submissions to the final approved budget.

The items listed below are illustrative of the types of questions and changes that are requested. They represent circumstances where desired spending has been deemed beyond the available capacity of the business or customers to afford.

Budget Reductions Made by SLT:

- Eliminate 4th Financial Analyst – staffing should be 3 FA's plus Accounting Clerk plus FIS back fill.

- Reviewed assumptions related to new building and addressed surplus land and updated expected acquisition costs.

- Confirm new building treatment, affiliate charges and expected occupancy date

- Provide for key investments – engagement $50k, Training $50k, Policy Review $100k FS $50K

- Update strategic items projects funding from $250,000 to $175,000 (related to policy review, customer engagement and training budgets.

IR: 1-SEC-4

[Ex.1]
Please provide copies of all benchmarking studies, reports, and analysis that the Applicant has undertaken or participated in since 2013, and are not already included in the application.

Response:

BPI has participated annually in the MEARIE Management Salary Survey Of Local Distribution Companies in the years 2014 and 2016.

Attachment 1-SEC-4A: 2014 MEARIE Survey

Attachment 1-SEC-4B: 2016 MEARIE Survey

IR: 1-SEC-5

[Ex.1]
Please provide a list of measurable outcomes that ratepayers can expect the Applicant to achieve during the Test Year. Please explain how those outcomes are incremental and commensurate with the rate increase the Applicant is seeking in this application.

Response:

With the removal of the building and other changes presented in 1-Staff-1 b), BPI is requesting an increase of $1,530,842 in revenues, or 9.3% in distributions rates. For this increase, customers can expect BPI to continue to achieve above- standard performance on its balanced scorecard in the areas of customer satisfaction, public policy responsiveness and operational efficiency. BPI's customers will also benefit from the introduction of time of use web presentment and the improved outage communications as a result of outage management improvements.

While consistent performance is not necessarily an <u>incremental</u> performance outcome, the operating reality is that, due to inflationary pressures and asset and system aging, in some instances it costs more to maintain the same level of performance.

As discussed in the Application, there are several risks which may prevent BPI from continuing its performance in these scorecard metrics. BPI's current CIS 20+ years old, well beyond its useful life, and contains extensive customization. The market share for the vendor is decreasing, and BPI risks increased costs or potentially discontinued service (in addition to CIS failure) on the current CIS. These items pose a risk to BPI's billing accuracy and customer satisfaction, as well as its public policy compliance/ responsiveness.

The replacement of the current Financial Information System will assist BPI to better track trends, productivity improvements and cost drivers in order to assist with BPI's total cost metrics in the future.

The capital expenditures budget should allow BPI to deliver consistent reliability results, and to meet is scorecard reliability target.

IR: 1-SEC-6

[Ex. 1]
Please provide details of all productivity initiatives the Applicant has undertaken since 2013. Please quantify the savings achieved.

Response:

BPI can provide the following listing of productivity improvements. BPI notes that in some instances, increased productivity came in the form of completing increased work with the same amount of resources. In some instances, due to lacking systems for financial analysis, the savings were not quantifiable.

Please note: the savings are primarily completed on an estimate basis, using an “all else equal” assumption, and assuming measures are in place the full year. Rounded numbers have been used, especially where related to compensation data.

Department	Year	Name of Productivity Measure	Description	Quantified, annualized savings (if applicable	Notes
Customer Service	2015	Outsource Bill Printing	•more productive use of staff time. • decreasese in postage and mailing costs; • Savings related to asset maintenance and avoiding asset replacement (bill inserter machine) •enables the provision of additional services in the form of e-billing, an identified customer preference	20,000 in e-billing postage savings (2017); 14,000 in avoided asset maintenance; 25,000 in re-purposed staff time.	
SLT	2014	Corporate Services Restructuring	Restructuring of SLT - from 5 positions to 4, including a new dedicated resource for Customer Service, CDM and Communications. Regulatory and Corporate Services function absorbed within CFO role.	$ 140,000.00	The SLT was able to include dedicated positions for the same operational areas as before (merging Operations and Engineering, Finance and Regulatory/Admin) and new focus areas, with lower headcount
SLT + Finance	2014	Providing Services to affiliate companies	CFO assumed responsibility for BEC Group CFO responsibilities - allowing for cost to be shared	2014: $85,811 2015: $410,229 2016: $384,269 2017: $302,417	
Regulatory	2014	Mat leave not replaced w/ contract - regulatory. One-time savings only	One-time savings associated with completing work with a lower staff complement in Regulatory Department.	$ 90,000.00	one-time
Regulatory	2015	Manager of Regulatory not filled; Senior Analyst.	BPI did not fill the Manager of Regulatory role when it became vacant. A Senior Regulatory Analyst role was created.	$10,000	per year
Finance/Regulatory	2016	FIS	Integration of RRR, CoS and finanical requirements in the design of the FIS is expected to create synergies and efficiencies by allowing greater company access to self serve, improved audit trails and internal control.	Frees up staff resources for greater focus on analysis and quality assurance rather than data processing	
Finance	2014	IFRS - template	Purchased financial statement template from KPMG to minimize the work required to prepare IFRS compliance financial statements. Cost of $5,000 was less than the internal cost would have been.	Unknown avoided cost.	
Finance	2016	FIS Procurement	Sound RFI and RFP procurement process, including site vists, reference checks. Additionally established a Best and Final Offer Stage for top two vendors to ensure the highest value option was chosen, at the lowest cost.	$190,000 in annualized savings compared to previous quotes, including both capital and OM&A, occuring primarily in 2017 and beyond	
General	2016	IBEW Negotiations	The new language allowing for placing staff on standby in advance of a storm allows for more flexibility and coverage at minimal cost. Getting the IBEW to agree to move the Customer Premise Representative into the metering group allows us to expand metering team and better utilize this role.	Increased flexibility and risk mitigation related to outages and major events.	
General	2014	CUPE Negotiations	Added a 10 year service requirement to be eligible to OPEB. Although not a savings immediately - this will over time mitigate increases in our OPEB costs.	Future Savings TBD	
Corporate	2016	Payroll Administration	Payroll to be administered bi weekly rather than weekly	Negligible cost decreased, staff time refocused elsewhere in department.	
Billing	2016	Reduction in volume of wire transfers	Payments to Retailers is completed bi weekly rather than daily	Ability to refocus work on other tasks.	
Corporate	2016	eServices	Reduction in postage of 5%	2016: $15,000 2017: $20,000	
Settlements	2017	Web Presentment tool for C&I customers	Introduction of an online web presentment tool and invoice calculator for C&I customers	reallocation of ~ $8,000 worth of time to other department work by allowing customers a self serve option	
OPS	2014	Stores Reorganization	Assistant Stock Keeper position was determined to be redundant and eliminated.	$ 75,000.00	per year
ENG	2014	Engineering Reorganization	Resignation of Eng'g Manager (role was not replaced). Of the remaining 2 Eng'g Managers, one took on additonal responsibility for Metering.	$ 120,000.00	per year
OPS	2013 - 2015	OPS Succession Planning	2013 - reduced journeypersons by 1, 2014 - replaced 2 journeypersons with 2 apprentices, 2015 - added 1 General Foreperson	2013: $105,00 2014: $95,000 2015: $15,000 2017 expected impact: $27,500	savings from apprentices decrease annually as they move through apprenticeship program.

IR: 1-SEC-7

[Ex. 1]
Please provide details of what *incremental* productivity initiatives the Applicant plans to undertake in the Test Year. Please quantify the forecast savings that will be achieved.

Response:

Department	Year	Name of Productivity Measure	Description	Quantified, annualized savings (if applicable)	Notes
Billing	2017	Reduction in vendor support cost	Transition to preprinted bill 'shells' from in process printing.	Ability to refocus work on other tasks.	
Settlements	2017	Web Presentment tool for C&I customers	Introduction of an online web presentment tool and invoice calculator for C&I customers	Increased benefits to customer.	

IR: 1-SEC-8

[Ex.1]
Please provide a copy of all materials provided to the Board of Directors in approving this application, and the underlying Test Year budgets.

Response:

Attachments :

1-SEC-8 A Budget Report (Oct)

1-SEC-8 B Budget Report (Nov)

1-SEC-8 C Budget

Please also refer to the presentation attached as 4-Staff-40a.

The Board of Directors of BPI did not officially approve the 2017 cost of service application before it was filed. However, on December 16, 2015, the Senior Leadership Team of BPI did present a 2017 budget to the Board of Directors. As a result of that presentation the Board of Directors approved the following resolution;

THAT Whereas the Board of Directors have reviewed the proposed 2016 Budget and Multi year forecast presented by Management; and

Whereas Brantford Power Inc. has achieved strong returns in 2013 and 2014 and is currently forecasting a strong return in 2015; and

Whereas the proposed budget for 2016 reflects distribution revenues that continue to be based on a revenue requirement established pursuant to the 2013 costs of service distribution rate application process , and

Whereas this revenue requirement does not reflect adequate funding for transitional and new ongoing costs related to the implementation of certain Brantford Power Inc. strategic plan initiatives including the elimination of three operating facilities by the acquisition of an existing repurposed consolidated facility and the implementation of a new financial information systems, and

Whereas, the financial impact of these unfunded costs is a budgeted 2016 return that is significantly below the level of returns contemplated in the 2013 Cost of Service rate application and further that the current illustration of future 2017-2020 returns continue to reflect returns that are consistently

> ***below the 9.19% return on equity level currently identified by the OEB as the reasonable return on equity;***
>
> ***That the Brantford Power Inc. Board of Directors approve the 2016 Budget as submitted and direct Management to incorporate into the 2017 Cost of Service Distribution Rate application a revenue requirement request that is sufficient to recover Brantford Power Inc.'s prudently incurred cost of service necessary to achieve a reasonable return on equity at the level established by the Ontario Energy Board.***

Based on this resolution, the 2017 cost of service application was prepared with some very minor alterations. The Senior Leadership Team presented to the Board of Directors at their meeting of April 28, 2016 the highlights of the proposed cost of service rate application including the bill impacts prior to the filing of the application and the Board did not suggests any changes be made to the application based on the bill impact information provided.

IR: 1-SEC-9

[Ex.1]
Does the Applicant have a corporate scorecard or similar document? If so, please provide the 2015 and 2016 versions.

Response:

Yes, BPI uses a corporate scorecard for Key Performance Indicators which is reported to the BPI Board on a quarterly basis. The year end 2015 and first quarter 2016 is attached. The second quarter report has not yet been compiled or reported to the BPI Board.

Attachment 1-SEC-9 A 2015 KPIs

Attachment 1-SEC-9 B 2016 Q1 KPIs

IR: 1.0-VECC-1

Reference: E1/T1/S3/pg.2

a) Please provide the evidence that BPI's wage rates are lower than comparable utilities.

Response:

As discussed in section E1/T2/S3, BPI is referring specifically to wages for *skilled trades* falling behind the market rate in the area. In 2015, BPI undertook an informal survey of neighbouring utilities to assess the market rates for this type of labour in the area.

The survey focused on the wage rates for a linesperson, and the following utilities were included in the comparison:

- Brantford Power Inc.
- Burlington Hydro Inc.
- Canadian Niagara Power
- Energy+ Inc. (Prev CND)
- IBEW Outside
- Energy+ Inc. (Prev BCP)
- PWU
- Enersource
- Grimsby Power
- Greater Sudbury Utilities
- Guelph Hydro Electric Systems
- Haldimand County Hydro
- Horizon Utilities
- Kitchener-Wilmot Hydro Inc.
- London Hydro
- Milton Hydro Distribution Inc.
- Oakville Hydro
- Orillia Power
- Peterborough Utilities Services Inc.
- PowerStream Inc.
- Waterloo North Hydro Inc.
- Welland Hydro-Electric Systems

The responded provided their 2015 and/or 2016 rate for the position linesperson. The survey indicated that BPI had the lowest rates at $37.22 in 2015*, with the group average at $40.19, and the range (not including BPI) from $38.60 to $42.55.

> *with the exception of Haldimand County Hydro for 2015, which, as a result of its Acquisition by Hydro One, was expected to implement Hydro One wage rates effective 2016.

IR: 1.0-VECC-2

Reference: E1/T8/S1/pg.9-10

a) Please explain if Table 1.8 is showing improving or declining total cost efficiency.

Response:

BPI has assumed the reference is referring to table 1.8-B, Projected Total Cost and Efficiency Assessment. The table is indicating, based on the column “ % difference from predicted”, improving total cost efficiency over the full forecast period, with a temporary outlier in 2016. This temporary above- predicted cost in 2016 reverts to a favorable variance in 2017, and on the basis of the “3 Year Average Performance”, the results continue to be less than predicted costs in each of the forecast years. BPI believes 2016 outlier is associated with the one-time costs in the 2016 year related to facility relocation and system integration projects.

IR: 1.0-VECC-3

Reference: E1/Attachment 1-A/pg.25

a) Have all of the recommendations of the Convergys study (e.g. pages 25, 27) been implemented? If not please explain why not.

Response:

The table below outlines each recommendation from the Convergys Report, whether BPI has implemented it, and explanatory notes.

Convergys recommendations	**Implemented? (y/n)**	**Reason why not**
Coach reps on call handling, especially remaining calm and courteous when they encounter challenging situations	y	Customer Service Representatives were provided with a document outlining call flow standards and the mandatory elements to be covered on each telephone interaction. Performance expectations have been communicated to Customer Service Representatives, and coaching and feedback is provided as required.
Use positive language to influence the customer's perception of the interaction	y	Customer Service Representatives were provided with a document outlining call flow standards and the mandatory elements to be covered on each telephone interaction. Performance expectations have been communicated to Customer Service Representatives, and coaching and feedback is provided as required.

Convergys recommendations	**Implemented? (y/n)**	**Reason why not**
Utilize DataLink to aid in identifying and improving instances of lower Rep performance.	y	Both managers and Customer Service Representatives have been provided with access to DataLink, the survey vendor's database, where individual representative performance in the areas of level of understanding, being knowledgeable, being courteous, setting expectations and accuracy of responses to issues and questions is tracked and reported. To enable immediate feedback and service recovery efforts, low score alerts were also this year implemented, where managers are emailed when a customer provides a satisfaction rating of 1 or 2 based on their interaction with Brantford Power.
Set appropriate expectations for the customer by stating a timeline for resolution when possible, or giving clear next steps when not.	y	Customer Service Representatives were provided with a document outlining call flow standards and the mandatory elements to be covered on each telephone interaction. Performance expectations have been communicated to Customer Service Representatives, and coaching and feedback is provided as required.
Identify the type of issues and calls that require multiple contacts to resolve in order to improve processes and Rep training.	n	This analysis will require the survey vendor to cross-tabulate various data points to derive meaningful data and information on an ongoing basis. In the absence of this process, training and process improvement opportunities are identified through call monitoring, customer feedback, and escalation and complaint management.
Educate customers on self-service options for payments and account changes. Use customer bills, email marketing and Brantford's website to inform customers of self-serve options.	y	On-bill messaging and website updates are consistently used to promote e-Billing as a self-service option available to all customers. There is currently no available online option to modify account information.

Convergys recommendations	**Implemented? (y/n)**	**Reason why not**
Modify wording of Q10 (methods of contact attempted before your call)	y	This question was modified to capture and report all methods used by a customer in their attempt to resolve an issue. The survey was also modified to add an open-ended question to record verbatim comments and reasons why customers did not receive first contact resolution.
Specify prior contact with Brantford to best measure FCR	y	See above
Determine if call handling differences exist between business and residential customers	n	There is an insufficient sample of transactional survey responses from business customers to complete a meaningful analysis. Any differences between business and residential customer preferences and satisfaction are captured through the biannual survey process.
Measure which call types are handled most effectively and which have room for improvement	y	DataLink stores an ongoing record of customer satisfaction by call type and by Customer Service Representative for each survey attribute. Trends and opportunities for improvement can be easily identified.
Evaluate whether placing customers on hold or transferring them has an impact on satisfaction.	y	The Customer Effort Index (see below) will determine the extent to which placing a customer on hold has an impact on overall satisfaction. It will also indicate a customer's perception of how easy it is to do business with Brantford Power.
Develop a Customer Effort Index to measure and trend Effort	y	The Customer Effort Index has been added to the transactional survey process and will be tracked and reported on in 2016.

Convergys recommendations	**Implemented? (y/n)**	**Reason why not**
Stay on the line with customers while working through an issue when possible, rather than placing the Customer on hold.	y	Customer Service Representatives were provided with a document outlining call flow standards and the mandatory elements to be covered on each telephone interaction. Performance expectations have been communicated to Customer Service Representatives, and coaching and feedback is provided as required.
Identify early in the call process when a call should be transferred to reduce call times in instances of non-resolution.	y	Customer Service Representatives have been provided with call transfer procedures, in addition to protocol for referring or escalating issues to a manager for follow up. Escalated items are detailed, tracked and remain open in a SharePoint database until the customer is contacted and the issue resolved.
Ensure the website offers answers to commonly asked questions as well as opportunities for self-service especially concerning billing and making payment.	y	Bill messaging and website updates have been used to promote e-Billing as a self-service option available to all customers. The website also outlines options for customers to subscribe to automatic pre-authorized and credit card payments. There are currently no self-service options for online bill payments
Ask clarifying questions during calls to ensure both spoken and unspoken Customer needs are being met to prevent additional contacts from being necessary.	y	Customer Service Representatives were provided with a document outlining call flow standards and the mandatory elements to be covered on each telephone interaction. Performance expectations have been communicated to Customer Service Representatives, and coaching and feedback is provided as required.

IR: 1-0-VECC-4

Reference:

At the noted reference it states: "*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* [sic] *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*."

a) How many customers questioned the need for any change? Did the survey offer the status quo as an option?
b) What cost was given to the respondent as being associated with the each move option?

Response:

BPI is withdrawing the request for funding for its facility in the Bridge and Test Years. Please refer to the response to 2-Staff-7 for further information.

IR: 1.0-VECC-5

Reference: E1/Attachment 1-A/pg.25

a) Has BPI or its parent had any discussions with interested parties in the last 12 months with respect to the sale of BPI?

Response:

BPI or its parent has not had any discussion with interested parties in the last 12 months with respect to the sale of BPI.

Exhibit 2: Rate Base

IR: 2-Staff-7

(Continues on next page)

Ref: Exhibit 2, Tab 1, Schedule 1, pgs. 2-17
Ref: Appendix 2-C

With Regard to Brantford Power's proposed acquisition of land and building, please provide the following additional information:

a) Brantford Power states that the purchase of the property is not yet certain as of the filing of the application. Please provide a status update of the transaction, including:
   i) Has the final offer been accepted?
   ii) If so, what is the final purchase price?
   iii) Is the building currently occupied?
   iv) At what date will Brantford Power take possession of the building?
   v) Has a new lease been executed with the current tenant? If so, what is the term of the lease?

b) At page 13, Brantford Power states that it expects relocation to be underway by October 1, 2016 given that minimal changes are anticipated for the office portion of the facility. Please describe the changes that would be required to meet Brantford Power's space needs, with specific reference to:
   i) The current configuration of the office space as it compares to the configuration required to meet Brantford Power's specific organizational requirements;
   ii) The current configuration of common space as it compares to Brantford Power's needs;
   iii) The current finishes and furniture as compared to Brantford Power's needs;
   iv) Reconfiguration required to stock room, interior vehicle storage and any other utility space.

c) Brantford Power's analysis appears to be based on estimates provided by its real estate consultants. Has Brantford Power received actual construction/refurbishment estimates for the required work? If so, please provide an update to the proposed refurbishment costs, including contingencies.

d) Has Brantford Power retained a construction company to complete the required refurbishments? If so, please provide the proposed timeline to complete the work.

IR: 2-Staff-7 (continued)

e) Please provide a table which compares the staff workspace in square feet as indicated in the AECOM space requirements, the amount of workspace to be occupied by Brantford Power, the amount to be occupied by Brantford Power affiliates and the amount to be occupied by the existing tenant. On separate lines, please provide the same comparison for each of stock room space, interior vehicle storage, outdoor secure storage and total building space.

f) Based on the response to part e) above, please provide a comparison of the revenue requirement impact of including only the Brantford Power portion of the land and building in rate base with the revenue requirement impact of removal of non LDC operating costs and using rental income as an offset to OM&A, as proposed.

g) Please provide a calculation of the net present value of the option to lease which excludes the portion of the land and building applicable to Brantford Power affiliates and the remaining tenant.

h) At page 10, Brantford Power has provided an excerpt from a letter from AECOM that states:

> *Assuming the area is regularly shaped it should be more than adequate to accommodate Brantford Power's outdoor storage needs. An aerial view of the property indicates that the surrounding area is not developed. Improvements would be required to develop a secure site storage area.*

    i) Is the area regularly shaped?
    ii) Is it adequate to accommodate outdoor storage needs?
    iii) What improvements are required?
    iv) What is the proposed timeline for these improvements?
    v) What is the cost of these improvements?
    vi) Have these improvements been incorporated into the capital cost proposed?

i) OEB staff notes that Brantford Power has assumed that, despite uncertainties evident as at its May 4 application date, the transaction will be complete, refurbishments done and all staff relocated by December 31, 2016 to include this asset in the opening rate base for the 2017 test year. Is Brantford Power requesting OEB approval of its <u>proposed</u> cost in rate base for 2017? What treatment would Brantford Power propose for variances between proposed and actual cost?

j) Did Brantford Power consider applying for an ICM or an ACM during the IRM term to allow the OEB to consider the prudence of the <u>actual</u> cost of this asset for inclusion in rate base?

Response:

With its application updates, provided as part of its response to 1-staff-1b), BPI has removed the funding requests related to the facility relocation. In its original Application, BPI indicated that it had not finalized the deal regarding the purchase of the intended repurposed building at the time the Application was submitted. At this time, the facility relocation project has not progressed at a pace that BPI believes could allow for occupancy of the new building before December 31, 2016 as planned. The Board of Directors will be reviewing the status of this initiative at its October meeting.

As a result, and consistent with the Board Staff questions i) and j) above, BPI has removed the amounts provided for the relocation in the 2016 Bridge Year and 2017 Test Year, and plans to apply for an ICM application when the facility relocation is complete.

Please note, as the facility relocation is no longer being proposed for recovery through rates in this Application, interrogatories related to the new facility are no longer relevant, and responses to those questions are no longer necessary and have not been completed.

BPI has reflected on RRWF, tab 10 tracking sheet the impact of removing the relocation project from the Application and updating it for the continued occupancy of BPI's existing leased facilities.

IR: 2-Staff-8

(Continues on next page)

Ref: Exhibit 2 - Attachment A, pg. 16-17 (PDF 125-126)

"Some specific BPI Distribution System Plan cost savings are expected to be achieved through the following:

- *Asset condition inspections and comprehensive data collection will provide a better understanding of each asset's stage in their lifecycle which will lead to more cost effective decisions with respect to maintenance, refurbishment and replacement decisions. BPI has not been able to quantify the capital or System O&M savings resulting from this as BPI will complete the first full 3-year cycle of inspections using the ODM in 2017.*
- *Proactive maintenance and replacement of plant will reduce reactive maintenance costs and improve service to customers, will result in fewer and shorter duration outages and will have a beneficial impact on the cost of outages to customers. A structured program will also smooth financial rate impacts in an effort to avoid disruptive rate spikes to address the volume of plant reaching end of life. BPI has not been able to quantify the capital or System O&M savings resulting from this as the improved financial reporting and analysis tools in the financial information system was only implemented at the end of 2016.*
- *Joint use underground construction with telecoms, where appropriate, will reduce underground cable installation costs for replacement of existing underground subdivision cable at end-of-life. BPI has not*

been able to quantify the capital or System O&M savings resulting from this due to the unknowns related to which of the budget and forecast projects will allow BPI to share space and costs.

- *Improved use of the Geographic Information System (GIS) to capture and access plant attribute data (i.e. nameplate data, condition, inspection/maintenance histories, etc.) will aid in cost control through optimization of the asset's lifecycle. BPI has not been able to quantify the capital or System O&M savings resulting from this as BPI will complete the first full 3-year cycle of inspections using the ODM in 2017.*
- *Prudent investment in distribution automation (i.e. remotely operated switches), as part of Smart Grid development, will improve day-to-day switching operations and have a positive impact on improving outage restoration time thereby mitigating customer outage costs. BPI has not been able to quantify the capital or System O&M savings resulting from this as the current penetration level of the remotely operated switches does not yet provide sufficient coverage in the service area to identify quantitative improvements.*
- *Coordination of plant inspection with maintenance reduces operating costs. Contractors performing tree trimming and infra-red testing also carry out visual inspections of adjacent plant. Exception reports are generated, as required, for follow-up remediation efforts by BPI. BPI has not been able to quantify the capital or System O&M savings resulting from this because the practice has been in place for a number of years. This is an ongoing, persistent activity.*
- *The use of distribution system design standards purchased from Enersource in 2006, significantly reduces unit costs for standard development and equipment approvals. BPI has not been able to quantify the capital or System O&M savings resulting from this as the standards have been in place and in use since 2006. This is an ongoing and persistent activity.*
- *Certain maintenance activities (i.e. painting transformers) help extend the life of the equipment thereby deferring replacement costs for a number of years. BPI has not been able to quantify the*
- **IR: 2-Staff-8 (continued)**
- *capital or System O&M savings resulting from this as there are no 'control' assets that are not receiving maintenance to compare to.*
- *Mobile equipment (i.e. laptops and tablets) in use provides paperless access to GIS information, maps, schematics, drawings and standards for inspection crews and Operations supervisors. During the period of the DSP BPI intends to expand the use of mobile equipment to all work crews to enable Workforce Management. BPI has not been able to quantify the capital or System O&M savings resulting from this as full Workforce Management is not yet implemented.*

For a portion of the general plant projects, completing the implementation of the outage management system as the customer information system is being implemented rather than before will save BPI the cost of a second integration with the legacy customer information system. BPI did not quantify the savings attributable to completing the projects in this order."

a) Has Brantford Power estimated capital or system O&M savings for each of the cost saving sources listed above?
    i. If yes, please provide details of the calculation of O&M savings.
b) Are the trends in O&M spending related to these cost savings being tracked?
    i. If yes, please provide this data.

ii. If no, please describe the steps being taken by Brantford Power going forward to ensure adequate tracking of O&M spending trends and cost savings trends.

Response:

a) Brantford Power (BPI) has not estimated capital or system O&M savings for each of the cost savings sources listed above.

b) BPI is not tracking the trends in O&M spending related to these cost savings. Beginning in 2017, BPI plans to use the separate Job/Work Order functionality in its new FIS to enhance its ability to track possible areas of cost savings listed above. Additionally, BPI will identify appropriate units of measure for possible areas of cost savings listed above.

IR: 2-Staff-9

Ref: Exhibit 2 - Attachment A, pg. 18 (PDF 127)

"The Optimal Decision Model (ODM) used by BPI to prioritize system renewal projects continually benefits from this updated data. The ODM draws information from the GIS system and the Customer Information System (CIS) in addition to inspection reports and input from qualified staff. While the ODM continues to use asset condition assessment to determine remaining useful life, in addition to risk assessment to determine probable consequence of failure and probability of failure, and combines them according to the asset risk analysis flowchart, it has moved beyond this to develop asset deterioration models. In these models, the estimated service life and a deterioration curve are combined to determine the remaining service life.

By using deterioration curves, the remaining service life is determined using classification and regression trees. This analysis works best when there is detailed asset data available to determine condition influencing factors and to have a reasonable sample set. This method of analysis has helped BPI to more clearly define the risks and be better able to assign or implement risk mitigation strategies."

a) Please provide a concrete example of the ODM output results and show how these results are being used to prioritize projects.
b) Has Brantford Power tracked the effectiveness of implementing its ODM to date?
   i. If yes, please provide this data.
   ii. If no, please describe the steps being taken by Brantford Power going forward to ensure adequate tracking and effective implementation of the ODM results.
c) Does Brantford Power's asset management process identify specific projects or does it point to general areas of concern? Please provide details.

Response:

a) Please see Attachment 2-Staff-9, "ODM_Results 30.pdf". The following is a description of the columns in the report.

G3E_FNO – the asset class identifier. The asset classes are:

208 – Pole

306 – Primary Conductor

316 – Secondary Bus

209 – Structure

313 – Switch

314 – Transformer

G3E_FID – unique, asset identifier.

INSTALL_DATE – the installation date of an asset.

AGE – the current age of an asset (in years), the difference between the current year the year the asset was installed.

ESL – the Estimated Service Life generated by the ODM.

INSPECT_DATE – date the asset was last inspected.

YEARS_SINCE_INSP – the number of years since the asset was last inspected, the difference between the current year and the year the asset was last inspected.

CHI – the Condition Health Index of the asset. [0 – 4]

FOLLOWING_LC – a notation identifying if the asset is following the life curve for the asset class relative to its AGE as determined by the ODM. [Yes, Worse, Better]

ODM_ERL – the estimated remaining life (in years) of the asset as determined by the ODM.

POF – the probability of failure as determined from the CHI. [1 – 4]

CRI – the critical index as determined by the ODM. [0 – 100]

COF – the consequence of failure based on the CRI. [Minor, Moderate, Major, Catastrophic]

RISK_INDEX – the asset's risk score based on the CRI and POF. [1 – 400]

RISK_LEVEL – the asset's level of risk. [Low, Moderate, High, Very High]

Three rows have been highlighted in the example report file. Asset numbers 1439968 – 1439970. These three assets will be used to show how the results are used to prioritize projects.

Example 1 – 1439968 & 1439970 each have the same ERL and POF. They each have different CRI and RISK_INDEX but have the same RISK_LEVEL. As a result of the higher RISK_INDEX number, 1439970 would be prioritized over 1439968. It should be noted that with a Moderate RISK_LEVEL, neither pole would be identified for actual replacement.

Example 2 – 1439969 & 1439970 each have the same CRI. They have different ERL, POF, RISK_INDEX and RISK_LEVEL. As a result of the higher RISK_INDEX number, 1439970 would be prioritized over 1439969. It should be noted that with a Moderate RISK_LEVEL, neither pole would be identified for actual replacement.

c)

i) Brantford Power (BPI) has not formally tracked the effectiveness of implementing its ODM. On a formal basis, BPI reviews the annual output from the ODM and compares the year to year results

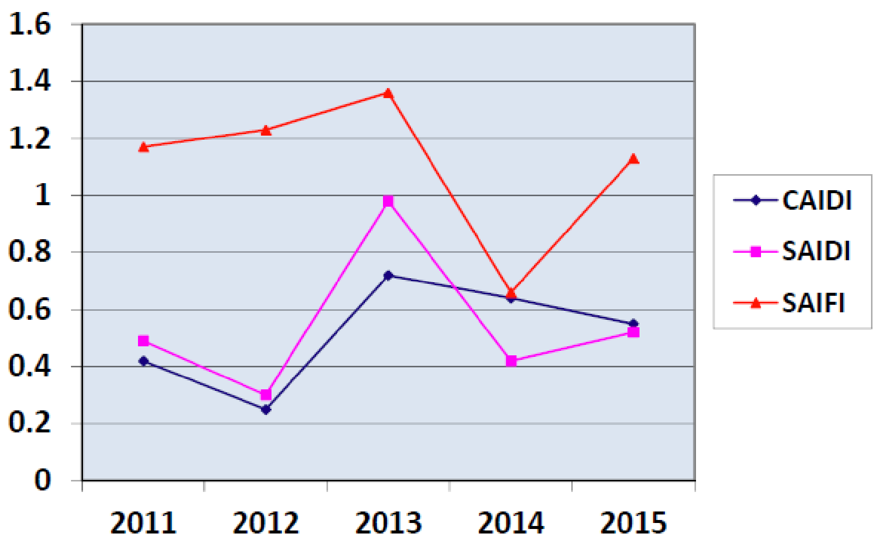
ii) BPI will develop an effectiveness measure in 2016 and take the necessary steps to implement it in 2017

c) BPI's asset management process identifies both individual assets that are of concern (the direct ODM output) and geographic groups of assets that are of concern. The geographic grouping process was explained in Exhibit 2 – Attachment A – DSP, Section 5.3.3.b on page 92. The group process selects asset clusters with the highest total risk score first.

IR: 2-Staff-10

Ref: Exhibit 2 - Attachment A, pg. 32 (PDF 141)

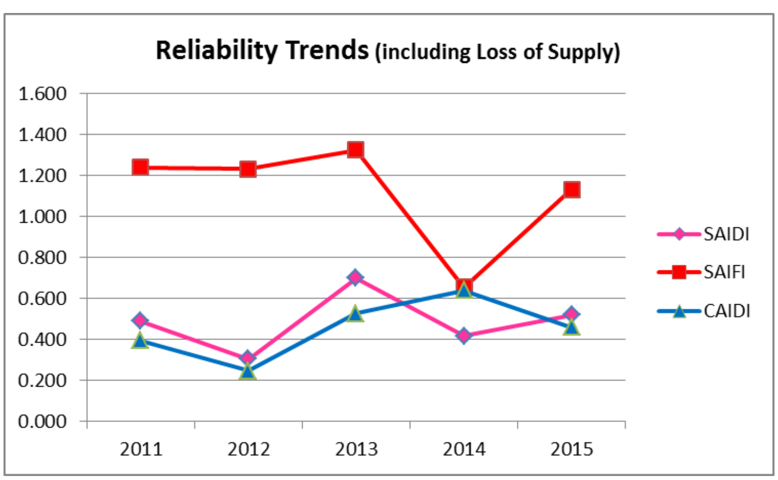
Figure 5: Reliability Trends for the Historical Period (including loss of supply)



a) In a revised graph, please present the 2011 - 2015 reliability trend information in Figure 5 excluding the December 2013 event.

Response:

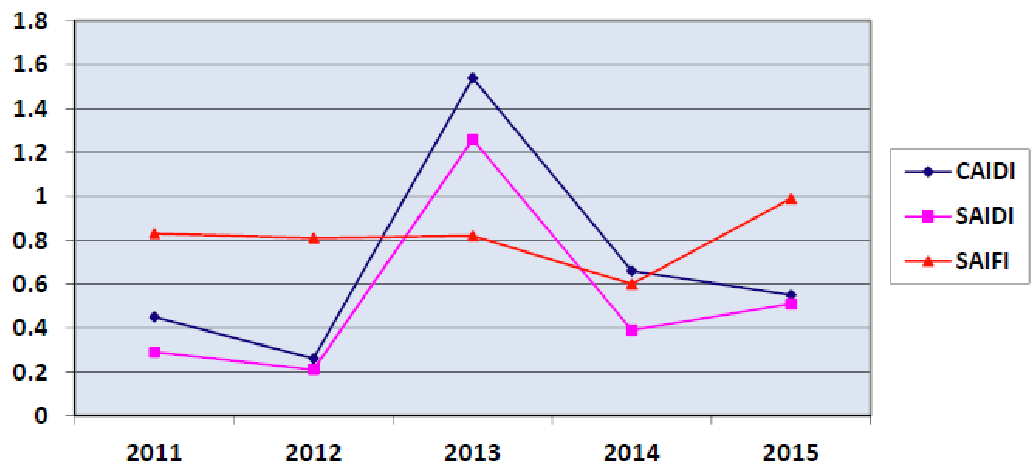
a) The following graph has been revised to exclude the December 2013 event. Please also note there was an incorrect data point for 2011 SAIFI which has been corrected. (Refer also to 2-Staff-11)



IR: 2-Staff-11

Ref: Exhibit 2 - Attachment A, pg. 33 (PDF 142)

Figure 7: Reliability Trends for the Historical Period (excluding loss of supply)



a) Please explain why the values in Figure 7 are higher when excluding loss of supply than when including loss of supply (i.e.: compared to Figure 5 shown in 2-Staff-3).

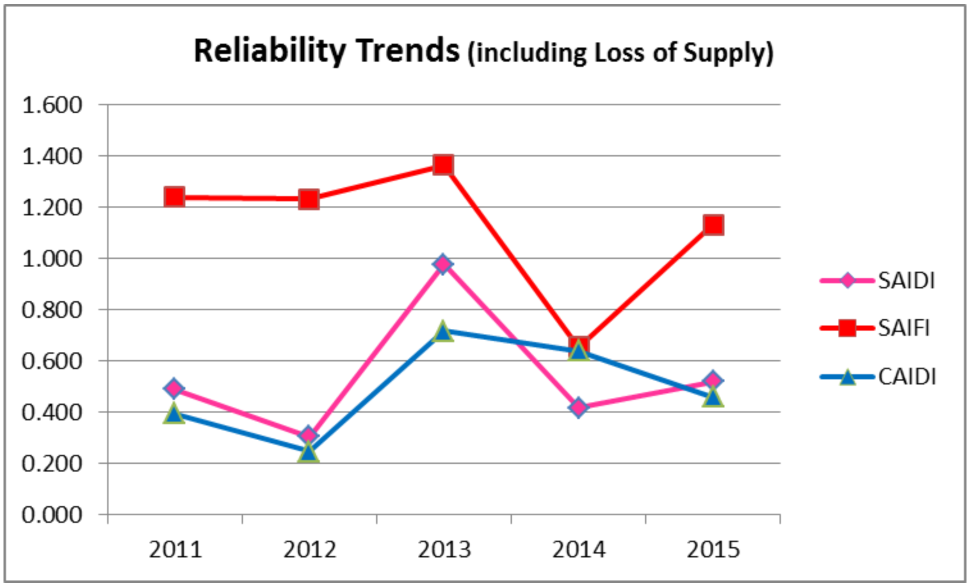
b) Please explain what caused the deterioration in SAIFI and SAIDI from 2014 to 2015.

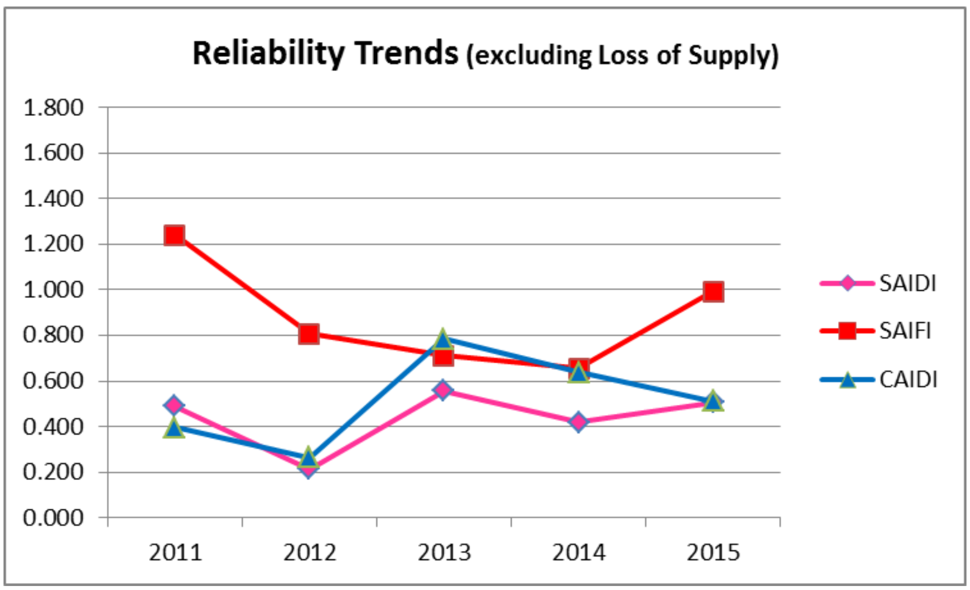
c) Please explain what caused the deterioration in SAIFI, SAIDI and CAIDI from 2011 to 2015.

d) In a revised graph, please present the 2011 - 2015 reliability trend information in Figure 7 excluding the December 2013 event.

Response:

a) During the process of answering this interrogatory it was discovered there were a few incorrect data points used for Figure 5 (2-Staff-10) and Figure 7. The two charts following have been corrected to reflect the proper data points as provided in Table 2.9-A of Exhibit 2. With these corrections the values excluding loss of supply are no longer higher than when including loss of supply.





b) On Feb. 9, 2015 a Motor Vehicle Accident caused an outage affecting 6,191 customers for a total of 6,558 customer hours. BPI crews were prevented from sectionalizing and switching as required to limit the interruption area and affected number of customers while Brantford Police Services (BPS) and the special investigations unit investigated the accident scene.

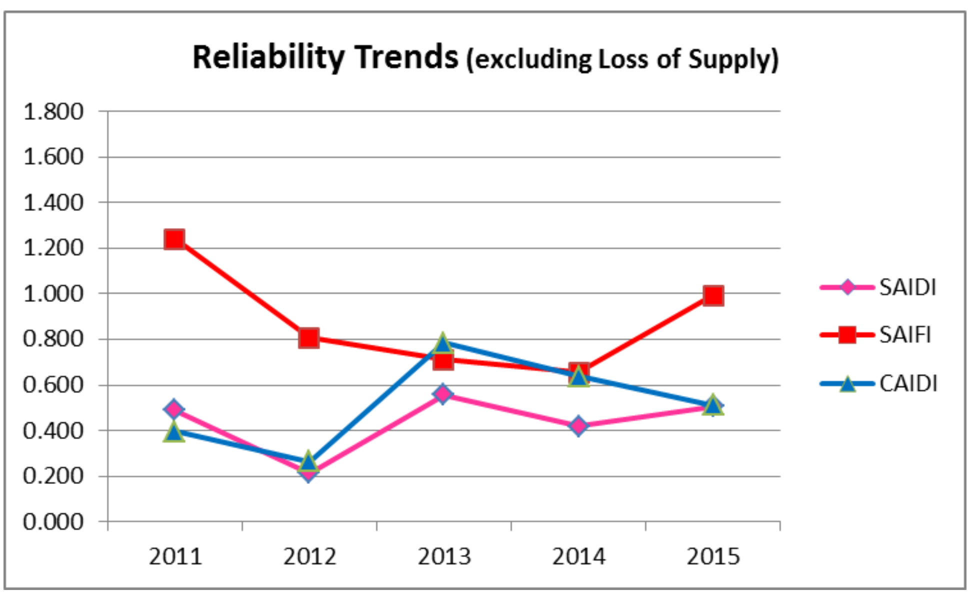
On Mar. 3, 2015 an ice and rain storm caused a large number of pole fires affecting 5,400 customers for a total of 7,837 customer hours. BPI crews were dealing with more outage sites than we had the resources to deal with.

These two issues account for 71% of the total duration of interruptions in 2015.

c) As per the response in part a) of this interrogatory, the data points used in Figure 7 for 2011 were not correct. The chart below shows the correct comparison of 2011 vs 2015. The data shows a slight deterioration in SAIDI and an improvement in SAIFI.

Year	2011	2015
Excluding Loss of Supply		
SAIDI	0.490	0.507
SAIFI	1.238	0.991

d) The following graph has been revised to exclude the December 2013 event. The graph also incorporates the adjustments from part a) of this interrogatory.



IR:2-Staff-12

Ref: Exhibit 2 - Attachment A, pg. 34-35 (PDF 143-144)

Figure 9: Short Duration Outages by Feeder

Feeder	2011	2012	2013	2014	2015	5-Year Average
12M12	4	0	0	0	0	1
12M13	0	1	1	0	1	1
12M23	4	8	3	6	1	4
64M21	5	5	1	2	8	4
64M22	3	3	1	7	4	4
64M23	2	1	4	2	1	2
64M24	2	5	7	4	1	4
64M25	2	5	2	1	1	2
64M26	6	9	13	14	5	9
64M27	9	5	5	3	8	6
64M28	10	6	3	5	5	6
64M29	5	4	1	2	4	3
64M30	8	5	4	1	1	4
PM1	9	3	1	3	2	4
PM2	4	0	3	5	4	3
PM3	0	0	0	0	0	0
PM7	0	0	0	0	0	0
PM8	9	2	11	4	6	6
Total Short Duration Outages	82	62	60	59	52	63

a) Please explain the reasons for the comparatively high number of outages for the following feeders:

- 64M26
- 64M27
- 64M28

- PM8

b) Please explain what is being done to improve performance of these feeders.

Response:

a) The four circuits identified are among Brantford Power's (BPI) longest feeders and therefore have more exposure to weather and animal related short duration outage causes.

- 64M26 – Of the identified short duration outage causes for this feeder, the majority were caused by animal contact followed by weather.

- 64M27 – Of the identified short duration outage causes for this feeder, the majority were caused by weather.

- 64M28 – Of the identified short duration outage causes for this feeder, the majority were caused by weather.

- PM8 – Of the identified short duration outage causes for this feeder, the majority were caused by weather.

b) BPI has started to install additional automatic reclose switches on a number of feeders in its distribution system. The feeders selected for automatic reclose switch installation are based on feeder outage performance and number of customers affected.

- 64M26 – BPI commissioned automatic reclose switch YAF-5 on the 64M26 feeder in February 2015. The automatic reclose switch was operating for 10 months of 2015 and the 2015 short duration outage performance on this feeder showed improvement over the previous four years.

- 64M28 – BPI commissioned automatic reclose switch SYM-17 on the 64M28 feeder in November 2015. The automatic reclose switch was operating for only 1 month of 2015.

- PM8 – BPI commissioned automatic reclose switch M6-3B on the PM8 feeder in February 2015. The automatic reclose switch was operating for 10 months of 2015. The short duration outage performance on this feeder has not yet shown improvement over the previous four year average.

- 64M27 – In addition to BPI customers, this feeder has Energy+ load embedded on the feeder. There is already an automatic reclose switch (JOH-S) installed between Energy+ and BPI parts of the feeder. Energy+ has Hydro One distribution customer load embedded on this feeder outside of Energy+'s service area. Operation of the JOH-S reclose switch is complicated by the connection arrangement with Hydro One. BPI discusses the operation of the JOH-S reclose switch with Energy+ and Hydro One on a regular basis.

IR: 2-Staff-13

Ref: Exhibit 2 - Attachment A, pg. 40 (PDF 149)

"To improve the SAIDI and SAIFI trends (excluding loss of supply), BPI plans System Service projects that will focus on shortening the duration of outages that customers experience."

a) Please clarify whether Brantford Power plans System Service projects that will focus on shortening the duration of outages that customers experience, as opposed to reducing the frequency of outages that customers experience?

b) If Brantford Power's primary focus is shortening the duration of outages, please explain how reducing outage duration will improve SAIFI.

c) Are there any projects that would reduce the frequency of outages? If yes, please provide details.

Response:

a) Brantford Power (BPI) plans projects that will shorten the duration of outages that customers experience and reduce the frequency of outages that customers experience. [Reference E2-Attachment A – DSP, Figure 53: System Service Capital Projects Forecast, page 99]

   a. BPI has two System Service projects active in 2017 that are expected to have an impact on duration and frequency.

      i. **SCADA –** The project activities will provide additional outage and fault reporting information to BPI's existing SCADA system. This additional information is expected to shorten the duration of outages that customers experience.

      ii. **Automated Reclose Switches** – The project activities will install additional automated reclose switches on feeders with lower than average reliability number statistics. The installation of each automated reclose switch is expected to reduce the number of customers on the feeder who are exposed to faults that lock out the feeder breaker until the fault can be isolated and service restored. For customers located along the feeder between the transformer station breaker and the automated reclose switch, they can expect a reduced frequency of outages.

   b. BPI has an additional System Service project active in the forecast years that is expected to have an impact on the duration of outages that customers experience.

i. **Downtown Automation** – The project activities will install automation between key pad mount switches in the downtown core. The automation will sense and isolate faulted feeder sections and restore power. Similar to the Automated Reclose Switches, this project is expected to reduce the number of customers on the feeder who are exposed to faults that lock out the feeder breaker until the fault can be isolated and service restored.

b) As noted in BPI's response to 2-Staff-13 a) above, BPI's primary focus is not only to shortening the duration of the outages but to also reduce the frequency of outages. By reducing the number of customers impacted by an outage, SAIFI will improve.

c) As noted in BPI's response to 2-Staff-13 a) above, both the Automated Reclose Switches project and the Downtown Automation project are expected to reduce the number of customers exposed to a fault. For the customers connected to the feeder between the transformer station breaker and the automated switch, they can expect a reduced frequency of outages.

IR: 2-Staff-14

Ref: Exhibit 2 - Attachment A, pg. 41 (PDF 150)

"BPI monitors progress of spending on capital projects in the current budget year.

This measure does not have a direct impact on the projects included in this DSP. This measure is an internal measure that allows BPI to better manage project spending and respond earlier in the year should the spending deviate from the approved budget within the applicable year."

a) With reference to the above statement, is Brantford Power's project expenditure monitoring focused upon individual project spending or on overall project spending in the current budget year?

b) If it is focused on overall project spending, is the number of projects changed in response to specific projects being over/under budget?

Response:

1) Brantford Power (BPI) monitors both project individual spending and overall project spending in the current budget year. Individual projects are monitored for 'on time' and 'on budget'. Overall project spending in the current budget year is the sum of all the current budget year project spending. The Capital Review Committee provides BPI's senior and middle leadership teams with details on the overall project spending in the current budget year on a monthly basis.

2) Monitoring is not focused solely on overall project spending. As a result of focusing on both individual and overall project spending in the current budget year, BPI is able to adjust the number of projects or a project's scope in response to other projects being over/under budget.

[Reference: E2- Attachment A – DSP, Section 5.2.3.a (page 29) and Section 5.2.3.b (page 37)]

IR: 2-Staff-15

Ref: Exhibit 2 - Attachment A, pg. 50 (PDF 159)

"Risk for individual assets is determined based on the following criticality determinants as part of the distribution system:

- *Condition of the asset.*
- *Location of the asset. For example, assets located along snow route roads or major intersections have a higher risk of deterioration.*
- *Frequency of maintenance of an asset would indicate a higher risk of failure of that asset if the maintenance program is not in place. Thus, the asset management program would assign a higher risk to this asset, notwithstanding maintenance, for the purpose of identification.*
- *Number of customers that are affected by the asset. This implies that higher the number of customers, the more critical that asset is.*
- *The usage history associated to that asset. Usage is the average energy consumed by the customers connected to a particular asset over a given period of time. Therefore a higher energy usage would assign a higher criticality to the asset."*

a) Please define "criticality" as used in the quoted paragraph.

b) Please specify which of the above listed criteria are considered "criticality related parameters".

c) Please specify which, if any, of the above listed criteria are considered probability of failure metrics, and which, if any, are considered as being consequence metrics.

d) Please describe the relationship between risk, criticality, probability of failure and consequence of failure.

Response:

a) Brantford Power (BPI) is using "criticality" in the context "of decisive importance with respect to the outcome; crucial."

b) All five of the above listed criteria are considered "critically related parameters".

c) Four of the five above listed criterial are considered probability of failure metrics. Only "Number of customers that are affected by the asset" is considered a consequence metric.

d) In BPI's ODM the terms 'risk', 'criticality', 'probability of failure' and 'consequence of failure' are related as follows:

Probability of Failure (PoF) is the likelihood that an asset will fail. Each asset has a PoF value. The value can be one of Unlikely, Somewhat, Likely and Almost Certain.

Criticality is the critical index number (from 0 – 100) for an individual asset. It is determined from the asset's critical factors, the critical criteria for each of the factors, the probability for each of the critical factors and the weighting of the critical factors.

Consequence of Failure (CoF) is the group that the critical index number fits into for the asset. The groups are: Minor, Moderate, Major and Catastrophic. Table 1: Consequence of Failure Grouping shows the relationship between the critical index value and the CoF grouping.

Table 1: Consequence of Failure Grouping

Critical Index number lies between	Consequence of Failure Group
0 to 20	Minor
20 to 40	Moderate
40 to 60	Major
60 to 100	Catastrophic

Risk is the product of the PoF with the CoF and is calculated for each asset. Table 2: Risk Grouping shows the relationship between PoF and CoF.

Table 2: Risk Grouping

PoF	**CoF**			
	Minor	Moderate	Major	Catastrophic
Almost Certain	High	High	Very High	Very High
Likely	Medium	High	High	Very High
Somewhat Likely	Low	Medium	Medium	High
Unlikely	Low	Low	Medium	Medium

IR: 2-Staff-16

Ref: Exhibit 2 - Attachment A, pg. 50 (PDF 159)

"The Risk Weight and Outage Weight were determined based on BPI's operation and engineering staff opinion and tested to ensure that those projects that were deemed of higher importance by staff were highest on the priority list. Risk Weight and Outage Weight have been reviewed by staff approximately every two years since the original determinations were made."

a) Please provide an example of "Risk Weight" and "Outage Weight" being changed following the most recent review of these weightings.
b) How does Brantford Power guard against changing the weightings based upon one-time events rather than (evolving) trends? (Said differently, how does Brantford Power differentiate between "signal" and "noise" in the data?)
c) How does Brantford Power ensure that weightings are changed in response to (evolving) future trends rather than "business as usual" historic patterns?

Response:

a) Brantford Power (BPI) and Urban and Environmental Management Inc. (UEM) worked together to develop the ODM. In Q4 of 2012, projects were created by grouping high risk assets in geographic clusters. Data on the number of outages reported in each project cluster was used along with the risk level of the assets in the project cluster to prioritize the project list. The "Outage Weight" has remained fixed since that time.

The "Risk Weight" is the Risk described in the response to 2-Staff-15. This risk is the product of an asset's Probability of Failure (PoF) and the asset's Consequence of Failure (CoF). An asset's CoF generally remains constant from year to year. An asset's PoF is subject to change as the asset ages.

b) BPI has not changed the 'outage' weightings since 2012. Since the system reliability measures are trended over a five-year period for the Scorecard Performance Measures, BPI believes that making adjustments to the weightings on a five-year cycle would ensure that the weightings are following the evolving trends rather than one-time events.

The 'risk' weightings change based on asset condition. The weightings are changed in response to the evolving trend of the condition of the asset.

c) BPI has not changed the ‘outage’ weightings since 2012. A change of weightings in 2017 would ensure that the any changes to the asset fleet over the five-year period would have taken effect and have had time to evolve.

The ‘risk’ weightings change based on asset condition. For assets with a Condition Health Index (CHI) value, this is based on the actual observed or tested condition of the asset. For assets that do not have a CHI, the value would change based on asset age.

IR: 2-Staff-17

Ref: Exhibit 2 - Attachment A, pg. 54 (PDF 163)

"The relation between PoF, CHI and ERL is as follows:

- *When the asset condition is very poor (CHI=1), regardless of the Estimated Remaining Life (ERL), the probability of failure (PoF) is Almost certain and given a PoF score of 4.*
- *When the asset condition is poor (CHI=2), regardless of the Estimated Remaining Life (ERL), the probability of failure (PoF) is likely and given PoF a score of 3.*
- *When the asset condition good (CHI=3) and the ERL (%) is less than 45%, the probability of failure (PoF) is somewhat likely and given a PoF score of 2.*
- *When the asset condition is excellent (CHI=4) and the ERL (%) is more than 45%, the probability of failure (PoF) is Unlikely and given PoF a score of 1.*

In the absence of historical condition data of an asset, the Estimated Remaining Life (ERL) is applied to determine the replacement dates."

a) In the case of the following statement permutation, please describe whether CHI or ELR governs, why they govern, and what happens to the PoF:
"When the asset condition is good (CHI=3) AND the ERL (%) is greater than 45%"

b) In the case of the following statement permutation, please describe whether CHI or ELR governs, why they govern, and what happens to the PoF:
"When the asset condition is excellent (CHI=4) AND the ERL (%) is less than 45%"

c) How often is ERL used to determine asset replacement dates due to an absence of historical asset condition data?

d) What are the most common reasons for an absence of historical asset condition data?

Response:

a) If it is available, CHI always governs the PoF. When available, the CHI is used to calculate the PoF, which returns the ERL. This ERL must fall within a range based upon the ERL Step model. If the ERL that is calculated using the asset's age [ERL(%) = (ESL-Age)/ESL] falls outside the ERL range determined by the inspected CHI, the ERL is adjusted based on the range it should fall within and the Inspection_ERL. These assets are then flagged for the user to investigate further.

Where ERL falls within the curve:

ERL = Inspection based ERL

Where the age determined ERL is "better" than the inspected ERL:

ERL = START + ((END-START) * (Inspection based ERL%) and Flagged with "Better"

b) Where the age determined ERL is “worse” than the inspected ERL:

ERL = START + ((END-START) * (Inspection based ERL%) and Flagged with “Worse”

c) If an asset does not have a CHI, the ERL is used to determine the asset replacement date. As of August 2016, there are 30,588 assets tracked in the ODM. There are 28,017 assets with a CHI. 91.6% of the assets have condition data and therefore only 8.4% of the assets use and ERL to determine asset replacement date.

d) The most common reason for an absence of historical asset condition data is the asset has not been inspected in the last three years. Prior to the use of tablet computers in the field for data collection, assets were inspected and the inspection details were recorded on paper. This method of record keeping resulted in inconsistent input of inspection data into the database.

IR: 2-Staff-18

Ref: Exhibit 2 - Attachment A, pg. 59 (PDF 168)

"According to the City'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. Based on this, BPI projects a customer growth rate in line with the predicted population growth rate of approximately 0.9%. This would imply a customer base of approximately 41,300 by the end of the forecast period."

a) Please reconcile the predicted 0.9% rate of customer growth with the expected 2.4% average population growth rate.

b) Although the growth is anticipated to take place over the next 15 years, the City is planning to service the majority of remaining city residential lands over the next 5 years, thereby requiring Brantford Power to accelerate its normal level of System Access expenditures.

   i. Is Brantford Power able to influence the timing and scope of the City-planned projects to optimize its own capital projects?

   ii. If yes, please explain why Brantford Power is not pushing back on the accelerated development since it appears to be causing early expenditures.

Response:

a) The 2.4% expected average population growth rate is a straight average over 20 years estimated by the City of Brantford and includes population growth outside of BPI's service area. The 0.9% customer growth is BPI's estimate of customer growth based on past experience and is consistent with the 0.96% geomean growth rate used in the development of the load forecast.

b) The City and the local land developers finds themselves in a unique position at this time. The existing land owners and developers who own land inside the current City boundary are pushing forward to ensure their lands are serviced before the new land the City is obtaining from the County of Brant is ready to be serviced. The City has said that it will be about five or so years before any of the new lands will be serviceable.

   While Brantford Power (BPI) can discuss the issues like servicing of the existing vacant residential and employment lands with the City, the timing and scope of work ultimately rests with the City and the land developers.

IR: 2-Staff-19

Ref: Exhibit 2 - Attachment A, pg. 86 (PDF 195)

"The capital project selection and prioritization methodology focuses capital funding on those assets that pose the greatest risk. By selecting asset replacement or renewal projects that focus on areas containing large numbers of high risk assets, it can be quantitatively shown that the projects selected are achieving the highest cost and value possible by reducing the overall system risk. The Risk Management Strategy is consistent with BPI's Corporate Risk Policy and manages the overall system risk. The Lifecycle Management Strategy uses asset information to plan infrastructure renewal projects based on asset condition assessments and Estimated Remaining Life (ERL). All assets are to be replaced at 90% of their useful life. This value is used as each asset's Estimated Service Life (ESL). Using Year of Installation, ESL, ERL, and Condition Health Index (CHI) for each asset in the Asset Database, the probability of failure (PoF) is calculated. PoF values are used in the ODM's risk matrix to calculate the risk level of each asset."

a) Please show how "useful life" as used in the sentence "All assets are to be replaced at 90% of their useful life" is determined.
b) Please show the quantitative relationships between the term "useful life" and the other terms used in the quoted paragraph: Estimated Service Life (ESL), Condition Health Index (CHI), Estimated Remaining Life (ERL) and Probability of Failure (PoF).
c) Is "Risk level" as used in the quoted paragraph synonymous with "Probability of Failure"?
d) Why aren't (very) low risk or similar assets allowed to run to fail?
e) Please explain why "the projects selected are achieving the highest cost … possible by reducing the overall system risk" is the correct strategy for Brantford.

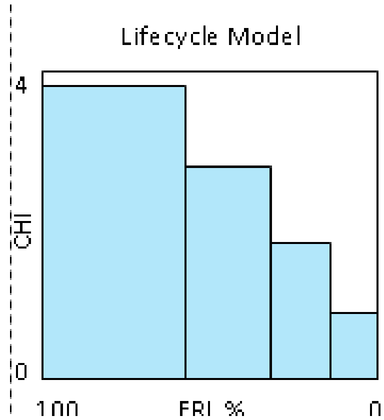
Response:

a) "All assets are to be replaced at 90% of their useful life" or in other words the Estimated Remaining Life (ERL) has fallen below 10%. At this point the CHI = 1 (asset condition is very poor) and the Probability of Failure (PoF) is almost certain.

b) The terms are related as follows.

   Useful Life = ESL

   An asset with inspection history has a CHI score. A CHI score between 2 and 4 equates to an ERL% between 11% and 100%. A CHI score of 1 equates to an ERL% between 0% and 10%. This is shown in the ERL Lifecycle Step Model shown immediately below.



An asset with no inspection history will have its ERL (%) determined from the following equation: ERL (%) = (ESL – Asset Age)/ESL

PoF is determined from the asset's CHI or from the asset's ERL%. The relationship between CHI, ERL and PoF is shown in Table 1: Risk Matrix.

Table 3: Risk Matrix

Condition Health Index (CHI)		Estimated Remaining Life Percentage (ERL %)	Probability of Failure (PoF)		Consequence of Failure (CoF)			
Score	Definition		Score	Definition	0-20	>20 – 40	>40-60	>60-100
					Minor 1	Moderate 2	Major 3	Catastrophic 4
1	Very Poor	0-10	4	Almost Certain	H	H	VH	VH
2	Poor	10-25	3	Likely	M	H	H	VH
3	Good	25-45	2	Somewhat Likely	L	M	M	H
4	Excellent	45-100	1	Unlikely	L	L	M	M

c) "Risk Level" is not synonymous with "Probability of Failure". The "Risk Level" (ranging from Low to Medium to High to Very High) is determined from the Risk Matrix which incorporates both an asset's Probability of Failure and its Consequence of Failure.

d) Based on the Risk Matrix shown in Table 1: Risk Matrix, an asset with (very) low risk has an estimated remaining life percentage of 25% or greater. An asset with this level of risk would not be flagged for replacement and may actually run to fail.

e) Projects are prioritized in order to produce the greatest reduction in risk across the system and have the greatest benefit to the Total Level of Service. By reducing the overall system risk, BPI is decreasing the chance of a service disruption which will influence SAIDI, CAIDI, and SAIFI which are primary measures of system performance.

IR: 2-Staff-20

Ref: Exhibit 2 - Attachment A, pg. 87 (PDF 196)

"BPI's asset deterioration models are divided into two parts. The first part determines the estimated service life of a group of assets and the remaining service life for each asset. The second part determines the deterioration curve for each of the groups of assets. Data requirements for each of the two parts, developed models, and future steps are also presented.

In order to determine remaining service life of an asset, and by extension, that of an asset class, service life data is required. This includes a remaining service life assigned to each asset by an inspector, using historic replacement data, or using industry standards for estimated service life."

a) Please show the quantitative relationship, if any, between the Estimated Service Life and Remaining Service Life of an asset.

b) Does Brantford Power use the pure age (i.e.: raw calendar age) of the asset to estimate the Remaining Service Life for most of its assets?

   i. If yes, please explain why an adjusted age based on a condition assessment is not used.

Response:

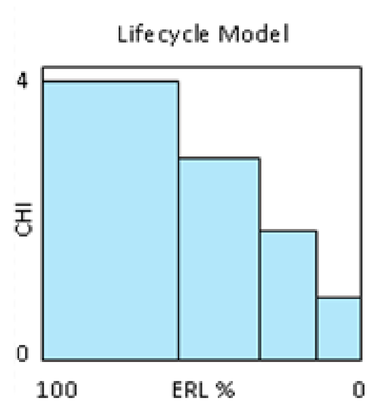
a) Estimated Remaining Life (ERL) is defined by the equation: ERL (%) = (ESL – Age) / ESL

   ERL determines PoF based on installation date and ESL

   When CHI is available and does not align with expected ERL, the ERL is adjusted. For example: If there is 1 year RSL, but an inspection with a CHI of 4, the ERL is adjusted to add remaining life to the asset.

   Each CHI has a defined RSL range; the ERL Step model in the database.

Figure 1: ERL Step Model



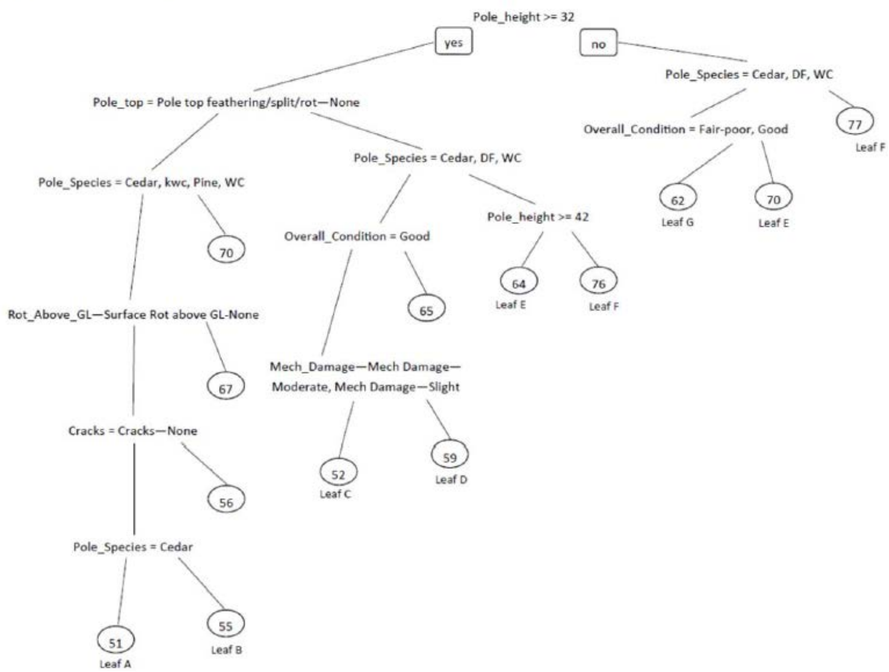
If the asset is at 90% of its ESL it will be placed at 90% of the way though the CHI step that it was recorded in. Since each CHI is recorded with a year, the asset is then aged forward from that year to the current year to get the current remaining life.

b) CHI is used and calculated an “adjusted age” based on the condition of the asset. When the CHI is not available to calculate the ERL, an ERL that is calculated from the ERL Step model is used. Brantford Power (BPI) does not use the pure age of the asset to estimate Remaining Service Life for most of its assets.

IR: 2-Staff-21

Ref: Exhibit 2 - Attachment A, pg. 89 (PDF 198)

Figure 46: Poles Tree Diagram



a) Please identify the decision criteria used at each bifurcation point in the tree diagram shown in Figure 46 (or confirm that the assumption in each case is left branch = "Yes" and right branch = "No").

b) Please confirm if the circled numbers equate to the percentage of Remaining Service Life of the pole.

   a. If this is not the case, please provide an interpretation of the numbers.

   b. If this is the case, please confirm that the tree diagram never results in a pole having a Remaining Service Life higher than “77”, or lower than “51”.

Response:

a) Brantford Power (BPI) confirms that the left branch = ‘yes’ and the right branch = ‘no’.

b) The circled numbers equate to the Estimated Service Life (ESL) and not the remaining service life %. This means that the ESL of the poles is always between 51 and 77.

IR: 2-Staff-22

Ref: Exhibit 2 - Attachment A, pg. 89 (PDF 198)

Ref: Exhibit 2 - Attachment A, pg. 90 (PDF 199)

"Deterioration curves were created by determining a representative age for each CHI and interpolating between them as well. Deterioration curves were developed for each leaf in the tree. Below is the scaled equation for the curve segments:"

$$CHI = \begin{cases} 4 \; if \; x \leq 0.35 \\ -8.7986x^2 + 5.843x + 3.0391 \; if \; 0.35 < x < 0.9 \\ 1 \; if \; x \geq 0.9 \end{cases}$$

"The equation for Transformer deterioration curves is given below:"

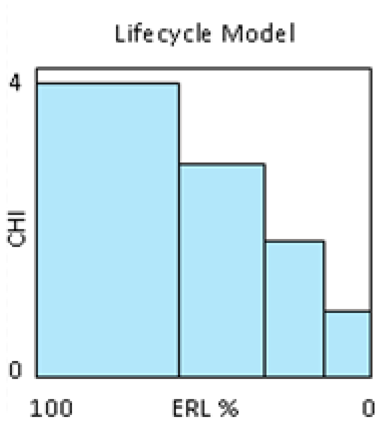
$$CHI = \begin{cases} 5 \; if \; x \leq 0.04 \\ 4.335x^2 - 8.853357x + 5.364 \; if \; 0.04 < x < 0.83 \\ 1 \; if \; x \geq 0.83 \end{cases}$$

a) Please explain how the above pole and transformer equations were derived, and provide examples of how they are used in practice.

b) What parameter does "x" represent?

Response:

a) As of 2014/2015 the equations are no longer being used. The determination of CHI was replaced by the ERL Step model.



b) When the equations were in use, "x" represented the useful life {age/ESL}.

IR: 2-Staff-23

Ref: Exhibit 2 - Attachment A, pg. 94 (PDF 203)

"Upstream capability (i.e. HONI TS, transmission, etc.) to accommodate new load and generation are determined through the Regional Planning process. Currently, as determined by Hydro One, there are generation connection limitations on the Z bus feeders at Brantford TS. No other generator connection limitations exist."

a) Please describe how the Z bus restrictions could be mitigated quickly if an interconnection request was received by a potential generation customer.

Response:

If a potential generation customer is located near (lies along) a feeder from the Y bus then Brantford Power (BPI) will provide the potential customer with a cost estimate to extend the Y bus feeder to the potential customer's location. To date, BPI has provided a cost estimate two times and connected one generation customer that would normally have been denied an offer to connect. In the second case, the potential customer has not yet advised BPI if it will be proceeding with their proposed generation project.

Another option used by BPI is to identify the potential for BPI to adjust the normal open points in its distribution feeders that could shift the supply feeder used at the potential generation customer's location. Previously, BPI has used this option to connect a generation customer.

IR:2-Staff-24

Ref: Exhibit 2 - Attachment A, pg. 96-97 (PDF 205-206)

Figure 51: System Access Capital Projects Forecast

Project	2017 Priority Ranking	2017 Forecast Cost	2018 Forecast Cost	2019 Forecast Cost	2020 Forecast Cost	2021 Forecast Cost
New Services (Roll Ins)	5	267,585	305,234	324,131	333,128	95,275
Non Residential Connections - Overhead	2	246,579	198,288	225,483	227,463	230,301
Non Residential Connections - Underground	3	469,527	386,584	382,993	384,443	385,934
New Overhead Transformers	NR	34,888	38,465	42,407	46,712	47,646
New Underground Transformers	4	321,680	354,652	391,004	430,688	439,302
Metering – New Customers	NR	90,508	91,389	92,565	94,034	94,034
Relocation – Shellard Lane	NR	0	165,690	0	0	0
Relocation – Dalhousie Street (Clarence to Brant)	NR	0	0	1,536,800	0	0
Relocation – Colborne-Dalhousie-Brant-Icomm Intersections	NR	0	0	124,000	0	0
Relocates – City & MTO	NR	20,000	232,800	20,000	381,550	110,000
New Subdivisions/Townhomes	1	739,250	783,605	857,530	872,315	295,706
Capital Contributions	NR	-479,000	-479,000	-479,000	-479,000	-479,000
Other Expenditures Below Materiality Threshold	NR	0	30,500	8,000	50,000	50,000
Total System Access		1,711,017	2,108,207	3,525,913	2,341,333	1,269,198

a) Please confirm if all projects shown in Figure 51 are based upon customer interconnection or other third party infrastructure-related requests.

b) Please confirm if all customer interconnection or third party infrastructure-related requests are considered to be non-discretionary.

   i. If yes, please explain what the priority ranking column in Figure 51 is indicating.

   ii. If no, please provide a list of customer interconnection requests that are considered to be discretionary.

c) Given the significant increase in System Access spending in the middle three years of this forecast, does Brantford Power have the latitude to defer any of these projects beyond 2021, or to flatten the overall forecast spend pattern?

Response:

a) Brantford Power (BPI) confirms that all projects shown in Figure 51 are based on customer interconnection or other third party infrastructure-related requests.

b) BPI notes that certain distributor activities such as the customer interconnection or third party infrastructure-related requests are a condition of the distributor's license. In order to meet the conditions of license, BPI has no freedom of judgment to choose whether to meet these obligations. BPI however ranks every project relative to the others for consideration in the budget year.

c) BPI has no latitude to defer any of the projects identified by subdivision and townhome developers or by the City of Brantford as these projects are activities that BPI is required to complete in order to meet the conditions of our license. If the developers' plans or the City plans are deferred then BPI will defer its project spending on the appropriate project that is deferred by the developer or the City.

IR: 2-Staff-25

Ref: Exhibit 2 - Attachment A, pg. 97 (PDF 206)

*“**Relocation – Dalhousie Street (Clarence to Brant):** The City is reconstructing this section and it is an opportunity to bring the system up to today’s standard and save money on restoration. The 3 blocks covered under this project do not have any electrical infrastructure allowing for growth. The project covers new junction boxes, vaults, concrete encased duct banks required for additional pipe and underground services. BPI needs to install plant consistent with the rest of the downtown area. This project is not material in the test year. The project will not be in-service until 2019.”*

a) Given the cost of the project described in the quoted paragraph ($1,536,800), are there other expenditures in the System Access or any other expenditure categories that can be deferred or rescheduled to levelize the rate of capital spend?

Response:

There are no projects in the System Access category that can be deferred or rescheduled to level the rate of capital spending in this category as these projects are related to distributor activities that BPI is required to complete in order to meet the conditions of our license.

IR: 2-Staff-26

Ref: Exhibit 2 - Attachment A, pg. 98 (PDF 207)

Figure 52: System Renewal Capital Projects Forecast

Project	2017 Priority Ranking	2017 Forecast Cost	2018 Forecast Cost	2019 Forecast Cost	2020 Forecast Cost	2021 Forecast Cost
Conversion to 27kV and/or Ownership	NR	63,669	66,853	70,195	73,705	77,391
RTU Replacement	NR	0	0	150,000	0	0
Lynwood Drive	NR	0	0	0	153,000	0
Pole Replacement	6	199,574	207,250	199,574	207,250	199,574
Rebuild – General	NR	26,841	29,592	32,625	35,969	39,656
Rebuild – Oak Park Road	NR	83,600	0	0	0	0
Rebuild – Vault Replacements	NR	91,219	77,677	78,936	79,898	81,176
Rebuild – Line Transformers	7	142,410	143,834	145,272	146,725	148,192
Metering - Replace Existing	NR	0	0	167,199	0	0
Total System Renewal		607,313	525,206	843,801	696,547	545,989

a) The Metering and RTU projects both have forecast single expenditures in year 2019, which is the peak expenditure year in the overall capital forecast. Please confirm if Brantford Power has the latitude to reschedule or defer spending in this category to levelize the rate of capital spend.

Response:

a) Metering – Replace Existing project is required in order to remain in compliance with section 5.1.3 of the Distribution System Code that was amended in 2014. Brantford Power (BPI) has until August 21, 2020 to install a MIST meter on any existing installation that has a monthly average peak demand during calendar years of over 50 kW. BPI has the ability to distribute the spending over the period from 2018 to 2020 but cannot defer spending outside the period covered by this DSP. BPI could advance this project to start in 2018 and extend it into 2020 in order to spread the cost over three fiscal years.

RTU Replacement project could be deferred. BPI has a spare RTU of same vintage available should the existing RTU fail while in service. In addition, Energy+, the 3/8th co-owner of the Powerline Municipal Transformer Station (PMTS), is currently evaluating their available options to allow PMTS to be controlled from the Energy+ control room. Their decisions related to the control of PMTS could impact both the scope and timing of the RTU Replacement project.

IR: 2-Staff-27

Ref: Exhibit 2 - Attachment A, pg. 99 (PDF 208)

Figure 53: System Service Capital Projects Forecast

Project	2017 Priority Ranking	2017 Forecast Cost	2018 Forecast Cost	2019 Forecast Cost	2020 Forecast Cost	2021 Forecast Cost
SCADA	10	113,800	63,900	63,200	63,200	63,200
Downtown Automation	NR	0	250,000	0	0	0
Automated Reclose Switches	11	195,755	117,042	96,640	144,960	144,960
Line Capacitors	12	112,000	112,000	0	0	0
Other Expenditures Below Materiality Threshold	NR	19,688	49,970	0	0	87,000
Total System Service		441,243	592,912	159,840	208,160	295,160

a) Expenditures in the System Service category peak in the first two years. Please confirm if Brantford Power has the latitude to reschedule or defer any of the 2017 and 2018 System Service projects to levelize the rate of capital spend.

Response:

a) Downtown Automation project is linked with the City of Brantford's downtown infrastructure renewal. The project would be deferred if the City of Brantford reschedules parts or all of their infrastructure renewal.

Line Capacitors project could be deferred or leveled over four years. Deferral of this project will reduce the impact the project could have on feeder voltage regulation and the expected power quality impact for Brantford Power's (BPI) customers with voltage sensitive manufacturing processes.

The other projects could be deferred or could have their scope changed to reduce project spending in each year. Deferral of the projects or reduction in the scope of a project will delay or reduce the benefits from the projects that BPI's customers would see.

IR: 2-Staff-28

Ref: Exhibit 2 - Attachment A, pg. 99-100 (PDF 208-209)

Figure 54: General Plant Capital Projects Forecast

Project	2017 Priority Ranking	2017 Forecast Cost	2018 Forecast Cost	2019 Forecast Cost	2020 Forecast Cost	2021 Forecast Cost
Capital Contribution to HONI (115kV Switches)	NR	0	3,752,548	0	0	0
Vehicle Replacements	13	425,000	400,000	350,000	225,000	375,000
Office Furniture and Computer Hardware	NR	35,800	17,800	36,900	10,400	40,800
SIP-Other	NR	0	57,188	396,200	0	0
Customer Information System Implementation	8	682,149	0	0	0	0
Operations and Customer Service OMS	9	239,904	0	0	0	0
Other Expenditures Below Materiality Threshold	NR	25,000	25,000	25,000	0	0
Total General Plant		1,407,853	4,252,536	808,100	235,400	415,800

a) Please explain why the planned contribution to the HONI 115 kV Switches project is treated as a General Project expenditure.

Response:

a) Table 1 in Section 5.1.1 of the Board's Filing Requirements for Electricity Transmission and Distribution Applications, Chapter 5 – Consolidated Distribution System Plan Filing Requirements identifies "capital contributions to other utilities" as an example of a General Plant investment category activity. Brantford Power believes it followed the filing requirements and treated the Capital Contribution to HONI (115kV Switches) appropriately.

IR: 2-Staff-29

Ref: Exhibit 2 - Attachment A, pg. 100 (PDF 209)

*"**SIP-Other** – This project is for the purchase of and implementation of other systems BPI deemed necessary in order to complete the systems integration projects as identified in the study completed in 2013. This project is not material in the test year.*

***Customer Information System Implementation** – This project is for the implementation of a new customer information system. In 2017, this is the #8 priority project.*

***Operations and Customer Service OMS** – This project is for the purchase of and implementation of a new outage management system. In 2017, this is the #9 priority project."*

a) Please confirm if it is possible to defer the SIP project into 2021 or out of the present forecast period. If not, why not?
b) Please confirm if it is possible to defer the Customer Information System Implementation project into 2021 or out of the present forecast period. If not, why not?
c) Please confirm if it is possible to defer the Operations and Customer Service OMS project into 2021 or out of the present forecast period. If not, why not?

Response:

a) Possible – yes, however the benefits that would accrue to customers will be deferred. Integrating the new systems (FIS, CIS, OMS) with remaining legacy systems and installation of a Work Force Automation system allows for better visibility through each system into the various operational models and transactions. This improved visibility will allow operations, engineering and customer service staff to respond with greater confidence to customers in case of inquiries or service orders from customers. The benefits that would accrue to customers would be improved operations; timely reporting; and improved/timely communication to customers/field staff through consistent and complete information across systems. Each of these benefits would improve the value of service provided by Brantford Power (BPI) to its customers. Completion of this project would be consistent with the findings from BPI's findings of customer priorities which placed Value Of Service as their top priority.

b) Possible – yes, however the benefits that would accrue to customers will be deferred. These benefits include a more robust service offering to customers including expanded self-service options and improved communications to customers. BPI believes these benefits help it improve the level and value of service the customer receives.

c) Possible- yes, however the benefits that accrue to customers will be deferred. These benefits include improved response by Brantford Power to outages and improved communication of information to customers impacted by outages. BPI believes these benefits help it improve the level and value of service the customer receives.

IR: 2-Staff-30

Ref: Exhibit 2 - Attachment A, pg. 101 (PDF 210)

"The plan identifies the following features:

- *To support the near and medium term needs, the following options were presented:*
  - Addition of capacitor banks at Powerline TMS to provide reactive power support
  - Addition of 115 kV transmission switching facilities at Brant TS
  - Implementing conservation targets
  - Demand response opportunities"

a) Please confirm if there are any capital costs in this DSP relating to the "implementation of conservation targets" or "demand response opportunities".
   i. If yes, please provide a list of these projects.

Response:

a) Brantford Power confirms there are no capital costs in this DSP relating to the "implementation of conservation targets" or "demand response opportunities".

IR: 2-Staff-31

Ref: Exhibit 2 - Attachment A, pg. 113-114 (PDF 222-223)

Figure 61: Customer Priorities

Key Driver	Residential Customers (91% of all customers)	Business Customers (9% of all customers)	Weighted Average Rating
Value of Service	19%	11%	18%
Affordability of Service	15%	9%	14%
Overall Quality of Customer Service	12%	21%	13%
Reliability of Service	9%	21%	10%
Billing Accuracy	11%	Not Ranked	10%
Overall Quality of Communication	8%	Not Ranked	7%
Being Leader in the Community	Not Ranked	10%	1%

a) Given that the top two drivers for Residential customers are Value and Affordability of Service, and both of these drivers are related to the cost of service, please show how Brantford Power has adjusted its capital spending plans to minimize rate impacts and to distribute expenditures evenly throughout the forecast period.

Response:

The higher ranked projects are planned to be completed early so that the benefits of each completed project accrue to the customers through the full life of the DSP. Lower ranked projects are spaced out through the life of the DSP to level expenditures in order to minimize the rate impacts.

Value of Service is the number 1 driver of customer satisfaction. In 2017 the projects ranked 1 to 5 are all related to providing electrical services to customers. Projects ranked 6 and 7 are related to public safety and restoring service to customers affected by equipment failure. The projects ranked 8 to 12 are all related to value of service. These five projects are noted in Table 2-Staff-31 A: Projects Linked to Value of Service Diver of Customer Satisfaction below.

Table 2-Staff-31 A: Projects Linked to Value of Service Diver of Customer Satisfaction

Project Name	2017 Priority	In-service Year
Customer Information System Implementation	8 of 13	2017
Operations and Customer Service OMS	9 of 13	2017
SCADA	10 of 13	2017-2021

Automated Reclose Switches	11 of 13	2017-2021
Line Capacitors	12 of 13	2017-2021

Affordability of Service is the number 2 driver of customer satisfaction. All projects have been ranked. Brantford Power (BPI) minimized the rate impacts and distributed the expenditures throughout the forecast period.

IR: 2-Staff-32

Ref: Exhibit 2 - Attachment A, pg. 123 (PDF 232)

"System Renewal:

- *2012 included the final year of a multi-year project to remove submersible transformers from residential areas and replace these with pad mount transformers.*
- *BPI forecasts the replacement of the Remote Terminal Unit (RTU) at Powerline MTS in 2019. The RTU will be 15 years old and at its end of life.*
- *BPI plans to replace the non-interval meters located at its GS>50kW customers in 2019. BPI is required by the OEB to complete the conversion of all remaining non-interval meters for this customer class no later than August 2020."*

a) Please confirm if the 15 year end of life assessment for the RTU is based on actuarial estimates or Brantford Power 's understanding that the equipment will not be serviceable after 2019.

b) Is the scheduled replacement of the non-interval meters in 2019 discretionary or non-discretionary (in respect of both need and timing)?

Response:

a) Brantford Power (BPI) based the end of life assessment for the RTU on both the actuarial estimate and its understanding that the equipment will not be serviceable after 2019. The actuarial estimate is based on BPI's Typical Useful Life for Remote SCADA (System Supervisory Equipment) assets as noted in Appendix 2-BB. BPI believes the equipment will not be serviceable after 2019 based on the recent trend in uptime of the equipment. BPI has implemented contingency measures to ensure that the RTU can be replaced with a spare unit should there be a catastrophic and permanent failure of the in-service RTU.

b) The scheduled replacement of the non-interval meters in 2019 is required based on section 5.1.3 of the Distribution System Code. BPI has until August 21, 2020 to install a MIST meter on any existing installation that has a monthly average peak demand during a calendar year of over 50kW. BPI scheduled the project for 2019 in order to defer the final technology selection decision to take advantage of the most recent advancements in wireless communication for MIST meters. BPI could advance this project to start in 2018 and extend it into 2020 in order to spread the cost over three fiscal years.

IR: 2-Staff-33

Ref: Exhibit 2 - Attachment A, pg. 125-126 (PDF 234-235)

"Relocation or replacement of existing plant normally results in an asset being replaced with a similar one, so there would be little or no change to resources for ongoing System O&M purposes (i.e. inspections still need to be carried out on a periodic basis as required per the DSC). There may be some slight life advantages when a working older piece of equipment is replaced with a newer one that would impact on System O&M repair related charges. Overall the system investments in this category are expected to put neutral pressure on System O&M costs.

Replacement of end-of-life plant with new plant will still require the allocation of resources for ongoing System O&M purposes. Repair would be the most significant System O&M activity impacted by new plant. Certain assets, such as poles, offer few opportunities for repair related activities and generally require replacement when deemed at end of normal life or critically damaged. Other assets such as direct buried cable offer opportunities for repair related activities (e.g. splices) up to a point where further repairs are not warranted due to end of life conditions. New primary cable installed in duct replaces direct buried primary cable and is expected to provide higher reliability and life. This will shift response activity for a cable failure from repair (System O&M) to replacement (Capital). If assets approaching end of life are replaced at a rate that maintains equipment class average condition then one would expect little or no change to System O&M costs under no growth scenarios but would still see upward System O&M cost pressure on positive growth scenarios (more cumulative assets to maintain each year). Replacement rates that improve equipment class average condition could result in lowering certain maintenance activities costs (e.g. pole testing, reactive repairs, etc.). Overall this is expected to put downward pressure on System O&M repair related costs."

a) Please confirm if the present level of incremental capital additions is expected to materially impact O&M costs on an annual basis through the forecast period.
    i. If yes, please quantify the impact.
b) Please confirm if System Renewal projects help reduce the requirement for emergency call-outs and unplanned outages by removing assets with higher risk of failure from the operating asset fleet.
    i. If yes, would this effect help to offset any anticipated O&M increases arising from incremental plant additions?
c) Brantford Power indicates in its evidence that System Renewal projects will not materially reduce overall O&M costs. Is it possible for Brantford Power to defer the proposed Renewal projects beyond the forecast period to mitigate rate impacts of other non-discretionary projects?

Response:

a) Brantford Power (BPI) confirms it does not expect the present level of incremental capital additions to materially impact O&M costs on an annual basis through the forecast period.

b) BPI confirms its belief that System Renewal projects help to reduce the requirement for emergency call-outs and unplanned outages. This is based on the assumption that the assets being removed from service through proactive replacement are the ones most likely to fail.

   i) BPI does not believe this will help offset any O&M increases arising from incremental plant additions. This is based on the assumption that overall weighted average useful remaining life of the asset fleet is not increasing rapidly enough to be noticeable.

c) BPI could defer the Lynwood Drive project (scheduled for 2020). The impact of this is expected to have a negative impact on reliability in the area. While the proactive replacement of the assets at the end of useful service life will result in outages (that negatively impact reliability statistics) the replacement of assets that have failed while in-service typically results in longer overall outages. The initial outage at the time of asset failure may result in an outage impacting all customers on the feeder or downstream of an automated reclose switch. The outage required while replacing the failed asset is typically longer than the outage required to proactively replace an asset.

IR: 2-Staff-34

Ref: Exhibit 2 - Attachment A, pg. 126 (PDF 235)

"BPI uses the following six criteria for prioritizing and pacing of capital expenditures.

1. *Safety*
2. *Access*
3. *Renewal*
4. *General Plant*
5. *Reliability*
6. *Timely, Accurate Communication"*

a) Please explain how Renewal and General Plant are used as "criteria" for prioritizing and pacing capital expenditures.

Response:

a) Brantford Power's (BPI) asset management objectives are to: [reference: E2 – Attachment A – DSP, Section 5.3.1.a, page 45]

BPI's asset management objectives are to:

1. Serve present and future customers,
2. Align utility interest with customer interest,
3. Optimize investment,
4. Focus on value for money,
5. Reflect regional and smart grid considerations, and
6. Support achieving of public policy objectives.

BPI's asset management prioritization criteria are linked to each of the asset management objectives noted above. The six criteria are ranked in order of importance.

For Renewal criterion, BPI prioritizes projects based on the risk level of the assets to be renewed. This was identified in the DSP as noted below.

System Renewal Projects

Identify

- System Renewal projects fall into three types.
    - Type 1 projects are identified in the asset management program as clusters of assets with a very high risk level and are nearing end of service life.

- Type 2 projects are identified in the asset management program as individual assets with a very high risk level and are at the end of their service life.
- Type 3 projects are identified through failure while in service.

Select

- BPI selects all Type 2 project assets for replacement in the next year.
- BPI selects the Type 1 cluster projects beginning with the project having the highest level of risk that can be mitigated through replacement of the assets in the cluster.
- BPI does not select Type 3 projects but will provide capital for their replacement in the next year's capital budget. The budget amount will be based on the recent history of asset failure while in service.

Prioritize

- BPI prioritizes the System Renewal projects based on the risk level. Determination of risk level was discussed in section 5.3.3.b on page **Error! Bookmark not defined.**.

Pace

- BPI paces System Renewal projects based on availability of staff and external resources that may be required.

For General Plant criterion, BPI prioritizes projects based on impact on overall level of customer satisfaction.

This was identified in the DSP as noted below.

General Plant Projects

Identify

- General Plant projects are driven by the internal needs identified by BPI.

Select

- BPI selects projects based on addressing customer preferences related to customer service issues and on addressing business needs related to the continued provision of service levels to BPI's customers.
- In the coming years, BPI will incorporate additional non-system physical plant, computer systems (hardware and software) and vehicles into the asset management system. This will provide BPI with additional tools to select and prioritize these assets for renewal and/or upgrades.

Prioritize

- BPI prioritizes General Plant projects based on impact on overall level of customer satisfaction.

Pace

- BPI paces General Plant projects over multiple years when at all possible.
- In this DSP, BPI is now in the process of replacing or upgrading a number of business systems (customer information system and outage management system). These are being paced over multiple years to avoid resource constraints in any one year.

IR: 2-Staff-35

Ref: Exhibit 2 - Attachment A, pg. 161 (PDF 270)

Project ID: MP-008
Project/Activity Name: Pole Replacement

Efficiency, Customer Value, Reliability – Alternatives (5.4.5.2 B1.c.iv)
The alternatives are run to failure or defer. The non-destructive testing has already identified particular poles as having less than 60% remaining strength and possibly of being in danger of imminent failure. Failure puts the public at risk of personal injury or property damage and puts customers at risk of unplanned outage. Choices related to the type of poles are considered. Choices are wood vs concrete. Concrete is used in heavy traffic areas; BPI identified specific areas based on susceptibility to motor vehicle accidents. Wood poles are less expensive and are therefore used throughout the majority of BPI's service area. Concrete poles sometimes require 3rd party assistance and often result in an outage. Replacements are on a like-for-like basis.

a) Please confirm if Brantford Power ever opts for the "run to failure" alternative for any of its assets.

b) Please confirm if the strategy of run to failure is primarily motivated by economic factors, or by other factors.

   i. If other factors, please provide details.

Response:

a) Brantford Power (BPI) experiences situations where some assets like transformers "run to failure". The failure is usually linked to the failure of a component (like a bushing) or is related to a weather event (like a lightning strike).

b) BPI confirms that the strategy of run to failure is primarily motivated by other factors. Specifically, the criticality of the asset as determined by the number of customers impacted by the failure of the asset and/or the energy usage related to the asset.

IR: 2-Energy Probe-9

Ref: Exhibit 2, Tab 1, Schedule 1

Is all of the $14,750,349 added to rate base in 2016, or was some of it added in 2015?

Response:

BPI is withdrawing the request for funding for its facility in the Bridge and Test Years. Please refer to the response to 2-Staff-7 for further details.

IR: 2-Energy Probe-10

Ref: Exhibit 2, Tab 1, Schedule 1, page 17

a) What is the current status of the acquisition and repurposing of the new facility?

b) What is the current forecast for the costs? Please provide an updated version of Table 2.1-D that reflects the current amounts spent and the amounts forecast to be spent in 2016.

Response:

a) BPI no longer believes it will be able to complete the acquisition and repurposing of the facility in the 2016 Bridge Year and 2017 test year. BPI expects to seek an ICM application for its facility relocation during an IRM year (i.e. 2018 to 2021) once the planning progresses further.

b) BPI is withdrawing the request for funding for its facility in the Bridge and Test Years. Please refer to the response to 2-Staff-7 for further information.

IR: 2-Energy Probe-11

Ref: Exhibit 2, Tab 1, Schedule 1

Did BPI do any sensitivity analysis around the option to lease calculations, such as changes in the weighted average cost of capital and/or inflation? If not, please explain why not. If yes, please provide a summary of the scenarios run, the assumptions and the results.

Response:

BPI is withdrawing the request for funding for its facility in the Bridge and Test Years. Please refer to the response to 2-Staff-7 for further information.

IR: 2-Energy Probe-12

Ref: Exhibit 2, Tab 1, Schedule 1

Please update Table 2.1-G to reflect the Board decision for Milton Hydro in EB-2015-0089.

Response:

BPI is withdrawing the request for funding for its facility in the Bridge and Test Years. Please refer to the response to 2-Staff-7 for further information.

IR: 2-Energy Probe-13

Ref: Exhibit 2, Tab 1, Schedule 1, page 16

a) Please provide a table that shows the breakout of the $751,669 in forecasted operating costs by line item. Please also show the line item savings that are forecasted to total $574,902.

b) Please provide a table that shows for each of 2013 through 2016 the total costs associated with the three current facilities that will be eliminated with the move to the new facilities.

c) Please confirm that there are no costs included in the 2017 revenue requirement associated with any of the three current facilities. If this cannot be confirmed, please quantify the costs included in the 2017 revenue requirement and explain why these costs are still included in the forecast.

Response:

BPI is withdrawing the request for funding for its facility in the Bridge and Test Years. Please refer to the response to 2-Staff-7 for further information regarding the OM&A impacts of this adjustment. As a result of the adjustment, BPI has updated OM&A amounts to reflect the continuation of leasing and related operating costs for the its current facilities leased from City of Brantford) in 2016 and 2017.

IR: 2-Energy Probe-14

Ref: Exhibit 2, Tab 1, Schedule 1, Table 2.1-H

BPI has reflected the OM&A cost associated with the new facilities of $406,502 in the calculation of the working capital component of rate base. Please explain why the OM&A savings of $574,902 have not been reflected in the working capital calculation.

Response:

BPI is withdrawing the request for funding for its facility in the Bridge and Test Years. Please refer to the response to 2-Staff-7 for further information.

IR: 2-Energy Probe-15

Ref: Exhibit 2, Tab 1, Schedule 1, Table 2.1-D

a) What is the cost associated with the land included in acquisition cost of $10,800,000?

b) If this amount is different from the $4,500,000 shown in the 2016 fixed asset continuity schedule, please explain fully.

c) BPI indicates that the land has an acquisition cost of $125,000 per acre. Please confirm that the land being purchased is 36 acres ($4,500,000/$125,000). If this is not confirmed, please explain fully.

d) BPI proposes to exclude 5 acres from rate base because this land is surplus to BPI's needs and could be severed and sold. How many acres does this leave for BPI and included in rate base?

e) Please provide the address for the facility.

Response:

BPI is withdrawing the request for funding for its facility in the Bridge and Test Years. Please refer to the response to 2-Staff-7 for further information.

IR: 2-Energy Probe-16

Ref: Exhibit 2, Tab 1, Schedule 1

Please confirm that there are no differences in the net book values calculated in Table 2.1-Q through 2.1-U as compared to the Tables 2.1-V through 2.1-Z. If this cannot be confirmed, please highlight any differences (other than WIP and non-regulated utility assets).

Response:

BPI confirms that there are no differences in the net book values calculated in Table 2.1-Q through 2.1-U as compared to the Tables 2.1-V through 2.1-Z.

IR: 2-Energy Probe-17

Ref: Exhibit 2, Tab 1, Schedule 1

a) Please confirm that Table 2.1-X for 2015 was based on audited financial actual data. If this cannot be confirmed, please provide an updated Table 2.1-X.

b) Please provide an updated Table 2.1-Y for the 2016 bridge year that reflects the most recent year-to-date figures available for 2016, along with the current forecast for the remainder of the year.

c) Based on the response to part (b) above, please provide an updated Table 2.1-Z for the 2017 test year that reflects the updated 2016 figures.

Response:

a) BPI confirms that Table 2.1-X for 2015 was prepared using audited financial actual data.
b) Please see table 2-EP-17.a below for the updated 2.1-Y.
c) Please see table 2-EP-17.b below for the updated 2.1-Z.

Table 2-EP-17.a

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard MIFRS
Year 2016

CCA Class [2]	OEB Account	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 1,042,539	$ 886,595	$ -	$ 1,929,134	-$ 727,640	-$ 202,859	$ -	-$ 930,499	$ 998,635
CEC	1612	Land Rights (Formally known as Account 1906)	$ 107,716	$ -	$ -	$ 107,716	-$ 13,342	-$ 2,035	$ -	-$ 15,376	$ 92,339
N/A	1805	Land	$ 181,961	$ -	$ -	$ 181,961	$ -	$ -	$ -	$ -	$ 181,961
47	1808	Buildings	$ 1,167,587	$ -	$ -	$ 1,167,587	-$ 277,134	-$ 27,623	$ -	-$ 304,757	$ 862,830
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 4,638,631	$ -	$ -	$ 4,638,631	-$ 1,083,539	-$ 113,604	$ -	-$ 1,197,143	$ 3,441,487
47	1820	Distribution Station Equipment <50 kV	$ 80,683	$ -	$ -	$ 80,683	-$ 74,941	-$ 212	$ -	-$ 75,153	$ 5,530
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 18,937,516	$ 217,021	-$ 30,000	$ 19,124,537	-$ 7,597,880	-$ 386,589	$ 20,000	-$ 7,964,469	$ 11,160,068
47	1835	Overhead Conductors & Devices	$ 14,289,930	$ 638,124	$ -	$ 14,928,054	-$ 5,143,292	-$ 270,530	$ -	-$ 5,413,822	$ 9,514,232
47	1840	Underground Conduit	$ 14,672,907	$ 106,388	$ -	$ 14,779,295	-$ 6,052,759	-$ 247,920	$ -	-$ 6,300,679	$ 8,478,617
47	1845	Underground Conductors & Devices	$ 20,859,901	$ 864,422	$ -	$ 21,724,322	-$ 6,828,907	-$ 675,641	$ -	-$ 7,504,548	$ 14,219,774
47	1850	Line Transformers	$ 18,741,828	$ 506,661	-$ 200,000	$ 19,048,488	-$ 7,612,285	-$ 490,264	$ 110,000	-$ 7,992,549	$ 11,055,940
47	1855	Services (Overhead & Underground)	$ 2,033,210	$ 181,777	$ -	$ 2,214,987	-$ 485,014	-$ 85,089	$ -	-$ 570,103	$ 1,644,884
47	1860	Meters	$ 4,496,620	$ 89,626	$ -	$ 4,586,246	-$ 1,904,213	-$ 239,531	$ -	-$ 2,143,743	$ 2,442,503
47	1860	Meters (Smart Meters)	$ 5,371,776	$ -	$ -	$ 5,371,776	-$ 2,115,705	-$ 371,730	$ -	-$ 2,487,435	$ 2,884,341
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1910	Leasehold Improvements	$ 51,184	$ -	$ -	$ 51,184	-$ 26,687	-$ 16,210	$ -	-$ 42,897	$ 8,287
8	1915	Office Furniture & Equipment (10 years)	$ 26,657	$ 4,800	$ -	$ 31,457	-$ 4,664	-$ 2,929	$ -	-$ 7,593	$ 23,863
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 167,104	$ 87,200	$ -	$ 254,304	-$ 143,791	-$ 17,775	$ -	-$ 161,566	$ 92,738
10	1930	Transportation Equipment	$ 3,366,382	$ 400,000	$ -	$ 3,766,382	-$ 2,274,178	-$ 181,301	$ -	-$ 2,455,479	$ 1,310,903
8	1935	Stores Equipment	$ 5,184	$ -	$ -	$ 5,184	-$ 1,244	-$ 518	$ -	-$ 1,762	$ 3,422
8	1940	Tools, Shop & Garage Equipment	$ 211,799	$ 25,000	$ -	$ 236,799	-$ 125,598	-$ 18,863	$ -	-$ 144,461	$ 92,338
8	1945	Measurement & Testing Equipment	$ 8,114	$ -	$ -	$ 8,114	-$ 1,217	-$ 812	$ -	-$ 2,029	$ 6,085
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 45,716	$ -	$ -	$ 45,716	-$ 30,661	-$ 12,054	$ -	-$ 42,715	$ 3,001
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 874,160	$ 89,337	$ -	$ 963,497	-$ 255,334	-$ 62,512	$ -	-$ 317,846	$ 645,651
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 5,056,929	$ -	$ -	-$ 5,056,929	$ 1,207,815	$ 117,508	$ -	$ 1,325,323	-$ 3,731,606
47	2440	Deferred Revenue[5]	-$ 754,016	-$ 479,000	$ -	-$ 1,233,016	$ 19,635	$ 24,303	$ -	$ 43,938	-$ 1,189,078
						$ -				$ -	$ -
		Sub-Total	**$ 105,568,160**	**$ 3,617,949**	**-$ 230,000**	**$ 108,956,110**	**-$ 41,552,576**	**-$ 3,284,789**	**$ 130,000**	**-$ 44,707,365**	**$ 64,248,745**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 105,568,160**	**$ 3,617,949**	**-$ 230,000**	**$ 108,956,110**	**-$ 41,552,576**	**-$ 3,284,789**	**$ 130,000**	**-$ 44,707,365**	**$ 64,248,745**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 3,284,789**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	-$ 181,301
Stores Equipment	$ -
Net Depreciation	-$ 3,103,488

Table 2-EP-17.b

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard MIFRS
Year 2017

			Cost				Accumulated Depreciation				
CCA Class [2]	OEB Account	Description [3]	Opening Balance	Additions [4]	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 1,929,134	$ 952,053	$ -	$ 2,881,187	-$ 930,499	-$ 346,697	$ -	-$ 1,277,196	$ 1,603,991
CEC	1612	Land Rights (Formally known as Account 1906)	$ 107,716	$ -	$ -	$ 107,716	-$ 15,376	-$ 2,035	$ -	-$ 17,411	$ 90,305
N/A	1805	Land	$ 181,961	$ -	$ -	$ 181,961	$ -	$ -	$ -	$ -	$ 181,961
47	1808	Buildings	$ 1,167,587	$ -	$ -	$ 1,167,587	-$ 304,757	-$ 27,623	$ -	-$ 332,380	$ 835,207
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 4,638,631	$ -	$ -	$ 4,638,631	-$ 1,197,143	-$ 113,604	$ -	-$ 1,310,748	$ 3,327,883
47	1820	Distribution Station Equipment <50 kV	$ 80,683	$ -	$ -	$ 80,683	-$ 75,153	-$ 212	$ -	-$ 75,365	$ 5,318
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 19,124,537	$ 205,362	-$ 30,000	$ 19,299,899	-$ 7,964,469	-$ 379,398	$ 20,000	-$ 8,323,867	$ 10,976,032
47	1835	Overhead Conductors & Devices	$ 14,928,054	$ 691,054	$ -	$ 15,619,108	-$ 5,413,822	-$ 301,037	$ -	-$ 5,714,859	$ 9,904,249
47	1840	Underground Conduit	$ 14,779,295	$ 91,220	$ -	$ 14,870,515	-$ 6,300,679	-$ 242,273	$ -	-$ 6,542,951	$ 8,327,564
47	1845	Underground Conductors & Devices	$ 21,724,322	$ 1,231,615	$ -	$ 22,955,937	-$ 7,504,548	-$ 694,513	$ -	-$ 8,199,061	$ 14,756,876
47	1850	Line Transformers	$ 19,048,488	$ 525,025	-$ 200,000	$ 19,373,513	-$ 7,992,549	-$ 493,490	$ 110,000	-$ 8,376,039	$ 10,997,474
47	1855	Services (Overhead & Underground)	$ 2,214,987	$ 267,585	$ -	$ 2,482,572	-$ 570,103	-$ 94,076	$ -	-$ 664,179	$ 1,818,393
47	1860	Meters	$ 4,586,246	$ 90,508	$ -	$ 4,676,754	-$ 2,143,743	-$ 237,566	$ -	-$ 2,381,309	$ 2,295,445
47	1860	Meters (Smart Meters)	$ 5,371,776	$ -	$ -	$ 5,371,776	-$ 2,487,435	-$ 371,730	$ -	-$ 2,859,165	$ 2,512,611
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1910	Leasehold Improvements	$ 51,184	$ -	$ -	$ 51,184	-$ 42,897	-$ 6,279	$ -	-$ 49,176	$ 2,008
8	1915	Office Furniture & Equipment (10 years)	$ 31,457	$ -	$ -	$ 31,457	-$ 7,593	-$ 3,169	$ -	-$ 10,763	$ 20,694
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 254,304	$ 35,800	$ -	$ 290,104	-$ 161,566	-$ 30,374	$ -	-$ 191,940	$ 98,163
10	1930	Transportation Equipment	$ 3,766,382	$ 425,000	$ -	$ 4,191,382	-$ 2,455,479	-$ 218,274	$ -	-$ 2,673,753	$ 1,517,629
8	1935	Stores Equipment	$ 5,184	$ -	$ -	$ 5,184	-$ 1,762	-$ 518	$ -	-$ 2,280	$ 2,904
8	1940	Tools, Shop & Garage Equipment	$ 236,799	$ 25,000	$ -	$ 261,799	-$ 144,461	-$ 19,287	$ -	-$ 163,748	$ 98,051
8	1945	Measurement & Testing Equipment	$ 8,114	$ -	$ -	$ 8,114	-$ 2,029	-$ 812	$ -	-$ 2,841	$ 5,273
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 45,716	$ -	$ -	$ 45,716	-$ 42,715	-$ 12,054	$ -	-$ 54,769	-$ 9,053
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 963,497	$ 90,760	$ -	$ 1,054,257	-$ 317,846	-$ 68,515	$ -	-$ 386,361	$ 667,896
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 5,056,929	$ -	$ -	-$ 5,056,929	$ 1,325,323	$ 117,508	$ -	$ 1,442,831	-$ 3,614,098
47	2440	Deferred Revenue[5]	-$ 1,233,016	-$ 479,000	$ -	-$ 1,712,016	$ 43,938	$ 36,507	$ -	$ 80,445	-$ 1,631,571
						$ -				$ -	$ -
		Sub-Total	**$ 108,956,110**	**$ 4,151,982**	**-$ 230,000**	**$ 112,878,092**	**-$ 44,707,365**	**-$ 3,509,520**	**$ 130,000**	**-$ 48,086,885**	**$ 64,791,207**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 108,956,110**	**$ 4,151,982**	**-$ 230,000**	**$ 112,878,092**	**-$ 44,707,365**	**-$ 3,509,520**	**$ 130,000**	**-$ 48,086,885**	**$ 64,791,207**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]						- 100,000			
		Total						**-$ 3,609,520**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	-$ 218,274
Stores Equipment	$ -
Net Depreciation	-$ 3,391,247

IR: 2-Energy Probe-18

Ref: Exhibit 2, Tab 1, Schedule 1

Please explain why BPI continues to add capital expenditures on meters in the meters line rather than the smart meters line on the fixed asset continuity schedules.

Response:

Brantford Power (BPI) treats all of it new revenue meters as 'meters' rather than differentiating between 'smart meters' and some other kind of meter. BPI confirms that all new revenue meters used for customers with a demand less than 50kW (residential and general service) are in fact smart meters as prescribed by the Distribution System Code.

IR: 2-Energy Probe-19

Ref: Exhibit 2, Tab 1, Schedule 1 &

Exhibit 2, Tab 3, Schedule 1

An amount of $218,274 is shown as fully allocated depreciation in the 2017 test year fixed asset continuity schedule in Exhibit 2, Tab 1, Schedule 1.

a) How much of this amount has been allocated to capital expenditures and how much has been included in OM&A?

b) Table 2.3-A in Exhibit 2, Tab 3, Schedule 1, shows a reduction in OM&A expenses used to calculate the working capital allowance in 2013 through 2016 of an amount that is equal to the fully allocated depreciation expense shown in the corresponding fixed asset continuity schedules. However, the 2017 reduction for working capital allowance is significantly less than the fully allocated depreciation expense shown in the fixed asset continuity schedule for the test year. Please explain.

Response:

a) Total fully allocated depreciation in 2017 is $218,274. Of this amount, $134,124 was included in OM&A and $84,150 was allocated to capital expenditures.

b) The working capital allowance in 2017 was reduced by the portion of fleet amortization allocated to OM&A expenses only, versus prior years that included fleet amortization allocated to OM&A and capital (in error), BPI has made the correction to 2013-2016 and updated Table 2.3-A in Table 2-EP-19 below.

Table 2-EP-19

Description	2013 Board Approved	2013 Actual	2014 Actual	2015 Actual	2016 Bridge Year	2017 Test Year
Distribution Expenses- Operation	1,232,931	1,440,365	1,569,559	1,551,035	1,697,963	1,633,794
Distribution Expenses- Maintenance	2,047,331	1,902,706	1,668,155	1,562,869	1,612,241	1,623,083
Billing and Collecting	2,558,831	2,577,446	2,872,826	2,840,394	3,233,610	3,088,680
Community Relations	97,000	37,976	10,279	11,505	16,585	17,390
Administrative and General Expenses	2,917,931	2,831,493	2,999,741	3,146,313	4,432,371	4,107,559
Donations-LEAP	-	22,006	22,407	22,606	23,500	25,000
Taxes other than Income Taxes	12,000	35,147	-	-	-	-
Less Allocated Depreciation	(75,766)	(69,709)	(78,755)	(94,259)	(111,304)	(134,124)
Power Supply Expenses	96,524,304	95,741,330	97,788,366	107,276,399	115,101,756	115,837,446
Total Working Capital Expenses	**105,314,563**	**104,518,759**	**106,852,577**	**116,316,862**	**126,006,722**	**126,198,828**

IR: 2-Energy Probe-20

Ref: Exhibit 2, Tab 5, Schedule 2

Please update and correct Table 2.5-A to reflect each of the following:

i) 2012 Plan and Actual data as indicated in the evidence and title of the table;
ii) Please provide the total budgeted capital expenditure for each year shown, in place of the Plan figure, other than for 2013, which should match the Board approved figures from EB-2012-0109 (please note that the budgeted capital expenditures need not be broken down into the four categories); and
iii) Replace the 2016 Actual figures with the most recent year-to-date actuals available along with the forecast for the remainder of the year.

Response:

The updated and corrected Table 2.5-A is shown below in Figure 1: Revised TABLE 2.5-A: Appendix 2-AB-Capital Expenditure Summary - 2012-2021.

Figure 2: Revised TABLE 2.5-A: Appendix 2-AB-Capital Expenditure Summary - 2012-2021

CATEGORY	Historical Period (previous plan[1] & actual)										Forecast Period (planned)				
	2012		2013		2014		2015		2016		2017	2018	2019	2020	2021
	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual[2]					
System Access	(1)	$1,503,450	(1)	$1,452,691	(1)	$1,098,678	(1)	$1,282,159	$ 1,125,682	$ 827,765	$1,711,016	$2,108,207	$3,525,912	$2,341,333	$1,269,199
System Renewal	(1)	$1,292,551	(1)	$ 447,280	(1)	$ 534,238	(1)	$ 744,528	$ 704,414	206,244	$ 607,313	$ 525,206	$ 843,801	$ 696,548	$ 545,989
System Service	(1)	$ 713,987	(1)	$ 553,194	(1)	$ 837,000	(1)	$1,531,276	$ 403,946	118,164	$ 425,798	$ 592,912	$ 159,840	$ 208,160	$ 295,160
General Plant	(1)	$ 434,228	(1)	$ 454,692	(1)	$ 324,327	(1)	$ 553,348	$16,134,256	403,368	$1,407,853	$4,252,536	$ 808,100	$ 235,400	$ 415,800
TOTAL EXPENDITURE	$5,190,830	$3,944,217	$2,901,500	$2,907,857	$3,973,218	$2,794,244	$5,655,273	$4,111,311	$18,368,299	$1,555,541	$4,151,981	$7,478,861	$5,337,654	$3,481,441	$2,526,147

(1) Historical "previous plan" data is not required unless a plan has previously been filed
(2) Six months of actual data; January 1, 2016 - June 30, 2016

IR: 2-Energy Probe-21

Ref: Exhibit 2, Tab 5, Schedule 4

Please explain the difference between the amount capitalized for the facility/project manager shown in Table 2.5-AS for 2016 of $154,392 and the amount of $100,714 noted in Table 2.1-D.

Response:

BPI is withdrawing the request for funding for its facility in the Bridge and Test Years. Please refer to the response to 2-Staff-7 for further information.

IR: 2-SEC-10

[Ex.2-1]

Please provide an update on the forecast in-service date of all 2016 material capital projects.

Response:

2016 Material Project	Forecast In-Service Date	Notes
New Services (Roll Ins)	On-going throughout the year with a final completion date of Dec. 31, 2016	Roll Ins are completed throughout the year and immediately placed in-service.
Non-Residential Connections – Overhead	On-going throughout the year with a final completion date of Dec. 31, 2016	Non-Residential Connections – Overhead are completed throughout the year.
Non-Residential Connections – Underground	On-going throughout the year with a final completion date of Dec. 31, 2016	Non-Residential Connections – Underground are completed throughout the year.
New Underground Transformers	On-going throughout the year with a final completion date of Dec. 31, 2016	• New Underground Transformers include any transformers that are not of the pole mounted overhead type. • Installation and commissioning of New Underground Transformers is installed throughout the year.
New Subdivisions/Townhomes	On-going throughout the year with a final completion date of Dec. 31, 2016	High Voltage (HV) servicing of New Subdivisions/Townhomes is commissioned and energised throughout the year.

2016 Material Project	Forecast In-Service Date	Notes
Total Capital Contributions	On-going throughout the year with a final completion date of Dec. 31, 2016	• Capital Contributions for New Subdivisions/Townhomes are recorded as the HV distribution system is energised. • Capital Contributions for Non-Residential Connections is recorded when the individual service is energised. • Recovery of costs from City/MTO relocation projects is recorded when the individual project is substantially complete.
Dalhousie (Drummond – Stanley) Rebuild	Unknown. City has deferred their UG services refurbishment project until 2019 at the earliest.	Costs treated as Work In Progress.
Pole Replacement	On-going throughout the year with a final completion date of Dec. 31, 2016	Identified poles are replaced throughout the year.
Rebuild – Line Transformers	On-going throughout the year with a final completion date of Dec. 31, 2016	Identified transformers are replaced throughout the year.
Rebuild – Vault Replacements	On-going throughout the year with a final completion date of Dec. 31, 2016	• Vaults include equipment vaults for submersible equipment, pads for pad mounted equipment, and any in-ground junction boxes or pull boxes. • Identified Vaults are replaced throughout the year.
Automated Reclose Switches	Dec. 31, 2016	
Line Capacitors	Dec. 31, 2016	

2016 Material Project	Forecast In-Service Date	Notes
Vehicle Replacements	Nov. 30, 2016	
Financial Information System Implementation	Dec. 31, 2016	
Land Purchase	Not expected to be completed in 2016.	
Building Purchase	Not expected to be completed in 2016.	
Facility Management	Not expected to be required in 2016.	

IR: 2-SEC-11

[Ex.2-1-1, p.9]
With respect to the proposed new facility:

a. Please provide any internal business case and all materials provided to the Board of Directors regarding the new facility and potential options.
b. Please identify and describe each of the 17 properties CBRE, and a rationale for each of the 15 properties that the Applicant chose not to investigate.
c. Please provide a copy of the AECOM reports and letters which provided advice regarding both, Property A and Property B.
d. Please provide a copy of the Feasibility Study regarding Property B.
e. Please provide a status update on the project.
f. Please provide the basis for AECOM's budgeted costs for the new facility.
g. Does the Applicant have a more accurate forecast of the total costs at this time? If so, please provide details, and the basis for it.
h. Please complete the following table:
a)

	Total (Admin and Operations)	**Admin Only**
In-Service Year		
Cost Type (Actual or Estimate)		
Total Cost ($K)		
Total Sq. Ft.		
FTEs (Year In-Service)		
FTEs (Test Year)		

Response:

BPI is withdrawing the request for funding for its facility in the Bridge and Test Years. Please refer to the response to 2-Staff-7 for further information.

IR: 2-SEC-12

[Ex.2-1-1, p.16]
Please explain how customers benefit from the purchase of a new building.

Response:

BPI is withdrawing the request for funding for its facility in the Bridge and Test Years. Please refer to the response to 2-Staff-7 for further information.

IR: 2-SEC-13

[Ex.2-5-1, p.1]
Please complete Appendix 2-AB by providing internal budgeted amounts for the year in the 'Plan' column. Please explain any material variances between plan and actual for each year.

Response:

Brantford Power (BPI) has completed Appendix 2-AB by:

i. Adding the columns for 2012 that were omitted from the original version of Appendix 2-AB.
ii. Adding the total internal budget amounts for each of the historical period years (2012 – 2016) in the 'plan' column.
iii. Adding the 2016 actual spending from January 1, 2016 – July 31, 2016.

This is the same table that was revised in reply to 2-Energy Probe-20.

Figure 3: Revised Appendix-2-AB-Capital Expenditure Summary - 2012-2021

CATEGORY	Historical Period (previous plan[1] & actual)										Forecast Period (planned)				
	2012		2013		2014		2015		2016		2017	2018	2019	2020	2021
	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual[2]					
System Access	(1)	$1,503,450	(1)	$1,452,691	(1)	$1,098,678	(1)	$1,282,159	$ 1,125,682	$ 948,613	$1,711,016	$2,108,207	$3,525,912	$2,341,333	$1,269,199
System Renewal	(1)	$1,292,551	(1)	$ 447,280	(1)	$ 534,238	(1)	$ 744,528	$ 704,414	236,303	$ 607,313	$ 525,206	$ 843,801	$ 696,548	$ 545,989
System Service	(1)	$ 713,987	(1)	$ 553,194	(1)	$ 837,000	(1)	$1,531,276	$ 403,946	131,293	$ 425,798	$ 592,912	$ 159,840	$ 208,160	$ 295,160
General Plant	(1)	$ 434,228	(1)	$ 454,692	(1)	$ 324,327	(1)	$ 553,348	$16,134,256	470,390	$1,407,853	$4,252,536	$ 808,100	$ 235,400	$ 415,800
TOTAL EXPENDITURE	$5,190,830	$3,944,217	$2,901,500	$2,907,857	$3,973,218	$2,794,244	$5,655,273	$4,111,311	$18,368,299	$1,786,599	$4,151,981	$7,478,861	$5,337,654	$3,481,441	$2,526,147

(1) Historical "previous plan" data is not required unless a plan has previously been filed
(2) Seven months of actual data; January 1, 2016 - July 31, 2016

The 2012 material variance of between actual and plan expenditures can be attributed to the following items:

i. Lower actual spending on installation of new underground transformers (-$408k),
ii. Lower actual spending on installation of new metering (-$139k),

iii. No conversion of privately owned high voltage distribution system equipment to ownership by BPI (-$159k),
iv. Lower actual spending on rebuild of failed or aging distribution system equipment (-$249k),
v. Higher number of poles replaced along Powerline Road and installation of new feeder ($346k),
vi. Increased number of lots serviced in new subdivisions ($217k),
vii. Increased capital contributions from developers, economic evaluations and municipal relocations (-$407k), and
viii. Thirteen other items that do not individually exceed the materiality threshold (-$511k).

There is no material variance between the 2013 Board approved plan and the 2013 actual expenditures.

The 2014 material variance between actual and plan expenditures can be attributed to the following items:
i. Higher number of poles replaced along Powerline Road and installation of new feeder ($174k),
ii. Lower number of lots serviced in new subdivisions (-$415k),
iii. Project to upgrade the phone system in customer service was not required (-$140k),
iv. Lower implementation costs on system integration projects due to delays in starting projects (-$247k), and
v. Thirty-five other items that do not individually exceed the materiality threshold (-$552k).

The 2015 material variance between actual and plan expenditures can be attributed to the following items:
i. Higher number of new underground services for non-residential customers ($196k),
ii. Higher number of poles replaced along Powerline Road and installation of new feeder ($134k),
iii. Lower number of lots serviced in new subdivisions (-$226k),
iv. Higher number of vaults and other underground structures replaced ($107k),
v. Higher number of transformers replaced ($227k),
vi. Lower actual spending on installation of new metering (-$113k),
vii. Project to purchase land for a new building was delayed (-$1,500k),
viii. Project to begin design and construction of new building was delayed (-$500k), and
ix. Forty other items that do not individually exceed the materiality threshold ($27k).

IR: 2-SEC-14

[Ex.2-Attach A, p.54-56]
For which assets has the ERL% been adjusted due to their observed CHI? Please provide details of the adjustments made to each of those assets.

Response:

Brantford Power (BPI) currently has 30,588 assets tracked in the ODM. BPI has 28,017 of these assets with a CHI. Assets with a CHI directly use the CHI in the determination of the Probability of Failure (PoF). Assets without a CHI will use the ERL% determined by the asset type Estimated Service Life (ESL) and Age in the determination of the PoF.

91.6% of the assets have a CHI. 8.4% of the assets use the calculated ERL%.

For the 8.4% of the assets without a CHI, the ERL% = (ESL –age)/ESL.

IR: 2-SEC-15

[Ex.2-Attach A, p.54-56]
Please complete the table included in Excel file 2-SEC-15 for all asset types and provide the response also in Excel format.

Response:

Please refer to Excel file “2-SEC-15.xlsx”.

IR: 2-SEC-16

[Ex.2]
Please add a column appendix 2-AA to the following appendices that show year-to-date actuals for 2016.

Response:

A revised Appendix 2-AA with the 2016 year to date actuals is shown below.

Projects	2012	2013	2014	2015	2016 Bridge Year	2016 YTD June Actuals	2017 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
System Access							
New Services - roll ins	249,530	92,219	76,695	127,577	181,777	45,152	267,585
New Non Residential Connections - Overhead	299,893	113,850	135,280	299,152	231,864	63,586	246,579
New Non Residential Connections - Underground	320,581	445,550	233,217	309,455	380,812	673,880	469,527
New OH Transformers	35,258	48,145	14,009	74,985	31,645	0	34,888
New UG Transformers	205,947	204,122	283,592	296,076	291,773	0	321,680
Metering- New Customers	157,760	93,524	111,576	92,454	89,626	31,620	90,508
Relocation- Shellard Lane	-	-	278,761	18,839	-	4,308	-
Dalhousie (Clarence - Brant Ave.) - New Build (PN278)	-	-	-	-	-	-	-
Colborne/Dalhouse/Brant Ave/Icomm Intersection (PN162)	-	-	-	-	-	-	-
Relocations- City & MTO	16,707	22,587	31,551	31,792	26,480	6,068	20,000
Sub-Total	1,285,676	1,019,995	1,164,681	1,250,330	1,233,976	824,614	1,450,766
New Subdivision Costs (Before Capital Contributions)							
Other Subdivision Costs	18,853	-	-	-	-	-	-
Diana Condos	124,328	4,992	-	-	-	-	-
Grand Valley Phase 2A & 2B	669,319	25	-	-	-	-	-
Wyndfield Phase 1	2,242	-	-	-	-	-	-
Wyndfield Phase 2A & 2B	8,584	606,537	-	-	-	-	-
Wyndfield Phase 3	-	534,218	- 174,899	8,861	-	-	-
Wyndfield Phase 4	-	-	394,727	6,965	-	-	-
Wyndfield Phase 5	-	-	-	156,429	-	-	-
Hardling Gardens	-	-	49,879	160,400	-	-	-
Heatherington Heights Condos	-	-	-	7,984	-	-	-
Wyndfield lots for 2016	-	-	-	-	260,216	-	-
Town Home Condos for 2016	-	-	-	-	35,490	3,151	-
Lots & Townhomes for 2017	-	-	-	-	-	-	739,250
Sub-Total	823,325	1,145,772	269,708	340,639	295,706	3,151	739,250
Capital Contributions							
Diana Condos	-55,374	0	0	0	0	0	0
Grand Valley Phase 2A & 2B	-315,372	0	0	0	0	0	0
Wyndfield Phase 2A & 2B	0	-368,883	0	0	0	0	0
Wyndfield Phase 3	0	-313,980	-113,280	0	0	0	0
Wyndfield Phase 4	0	0	0	0	0	0	0
Hardling Gardens	0	0	0	-125,793	0	0	0
Wyndfield Phase 5	0	0	0	-87,600	0	0	0
Lots & Townhmes for 2016-2017	0	0	0	0	-272,721	0	-369,528
City/MTO Relocations	-218,797	-10,697	-141,373	-36,232	-59,713	0	-66,425
GS customer connection economic evaluation	-16,008	-19,516	-77,282	-59,186	-146,566	0	-43,047
Sub-Total	-605,551	-713,076	-331,936	-308,811	-479,000	0	-479,000
Total System Access Net of Capital Contributions	1,503,450	1,452,691	1,102,453	1,282,159	1,050,682	827,765	1,711,016

Table continued on following page.

Projects	2012	2013	2014	2015	2016 Bridge Year	2016 YTD June Actuals	2017 Test Year
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
System Renewal							
Conversion to 27kV and/or Ownership	0	12,366	78,666	1,695	60,638	0	63,669
Colborne UG System Modifications	0	0	0	117,655	56,480	11,420	0
Dalhousie (Drummond - Stanley) - Deep Services (PN333)	0	0	0	0	108,314	934	0
D20 RTU Replacement	0	0	0	0	0	0	0
Lynwood Drive	0	0	0	0	0	0	0
Rebuild- Pole Replacements	442,854	204,016	188,648	157,832	207,250	85,513	199,574
Rebuild- General	111,786	109,692	83,057	25,826	24,345	0	26,841
Rebuild- Oak Park/403	0	0	0	0	0	0	83,600
Rebuild- Vault replacements	0	0	72,839	150,082	106,388	23,072	91,219
Rebuild- Line Transformers	55,378	121,206	180,966	226,958	141,000	85,305	142,410
Rebuild- Lynden Hills	1,083,360	0	0	0	0	0	0
Standby Adjustments	-400,826	0	-106,048	64,481	0	0	0
Metering- Replace Existing	0	0	29,875	0	0	0	0
Sub-Total	1,292,551	447,280	528,003	744,528	704,414	206,244	607,313
System Service							
SCADA	37,018	61,319	23,923	128	76,400		113,800
Downtown Automation Project	0	0	0	0	0		0
Powerline Rd. Feeder Upgrades	676,969	408,800	653,789	584,243	0	46,507	0
Automated reclosers	0	0	130,873	172,825	195,858	60,297	195,755
pole-top capacitors near end of feeder	0	0	0	0	112,000		112,000
Capacitor Study and Installation of Line Banks	0	51,125	28,415	703,834	0	2,915	0
Sub-Total	713,987	521,244	837,000	1,461,030	384,258	109,719	421,555
General Plant							
Automated Switches (115kV)- B12/B13	-	-	-	-	-	-	-
Asset Management & AM/FM & GIS	181,500	163,491	108,175	796	20,000	1,686	-
Vehicles	123,836	176,849	118,017	399,909	400,000	- 1,208	425,000
Office Furniture and Computer Hardware	114,036	10,605	21,277	6,733	92,000		35,800
SIP-Other	-	-	-	-	-		-
FIS Implementation Costs	-	-	-	-	845,907	392,663	-
CIS Implementation Costs	-	-	-	-	-		682,149
Operations and Customer Service OMS	-	-	-	-	-		239,904
Land	-	-	-	-	4,500,000		-
Building	-	-	-	-	10,149,635		-
Facility Manager	-	-	-	-	100,714		-
Sub-Total	419,372	350,946	247,469	407,438	16,108,256	393,141	1,382,853
Miscellaneous	14,856	135,696	79,318	216,156	120,688	18,672	29,243
Total	**3,944,217**	**2,907,857**	**2,794,243**	**4,111,311**	**18,368,299**	**1,555,541**	**4,151,981**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets ***(input as negative)***	-	-	-	-	-		-
Total	**3,944,217**	**2,907,857**	**2,794,243**	**4,111,311**	**18,368,299**	**1,555,541**	**4,151,981**

IR: 2.0 – VECC - 6

Reference: E1/T1/S1

a) Please provide the analysis which shows combining the three facilities is more cost efficient than the existing arrangements.
b) Please explain the conditions of the current lease which allow for early termination.
c) What plans does the city have for the properties currently occupied by BPI?
d) Please provide an update on the negotiations to acquire the existing building.

Response:

BPI is withdrawing the request for funding for its facility in the Bridge and Test Years. Please refer to the response to 2-Staff-7 for further information.

IR: 2.0 – VECC - 7

Reference: **E1/T1/S1/pg.17**

a) In the analysis of the existing vs new build why is there an adjustment for depreciation in the latter, but not the former (new build)?

Response:

BPI is withdrawing the request for funding for its facility in the Bridge and Test Years. Please refer to the response to 2-Staff-7 for further information.

IR: 2.0 – VECC - 8

Reference: E2/T5/S2/Table 2.5

a) Please provide the rationale for capitalizing the costs of the proposed facility manager.
b) Please provide any precedent for this form of accounting treatment.

Response:

BPI is withdrawing the request for funding for its facility in the Bridge and Test Years. Please refer to the response to 2-Staff-7 for further information.

IR: 2.0 – VECC - 9

Reference: E2/T1/S1/pg.7 & Table 2.5

a) The evidence summarizes the total estimated building space requirement as 37,000 sq. ft. Please reconcile that figure with the table at page 11 of the AECOM report which identifies total GSF of 13,167 for existing requirements.

b) Please explain the additional 20 FTEs (30%) increase in FTE over the 2015-2017 period which were incorporated into the requirements. Specifically identify all positions above the 56 actual FTEs in 2015 which are anticipated to be resident in the new facilities.

Response:

BPI is withdrawing the request for funding for its facility in the Bridge and Test Years. Please refer to the response to 2-Staff-7 for further information.

IR: 2.0 – VECC - 10

Reference: E2/T1/S1/Table 2.1-G

a) Does the square footage shown in this table include garage space?
b) If yes, please provide a breakdown of square footage by office and garage space separately for each of the comparators

Response:

BPI is withdrawing the request for funding for its facility in the Bridge and Test Years. Please refer to the response to 2-Staff-7 for further information.

IR: 2.0 – VECC - 11

Reference: E2/T9/S1

c) Please provide the outages (number and duration) for 2012 through 2015 by cause code.
d) Please explain how the proposed DSP is forecast to impact outages caused by defective equipment.

Response:

a) The following chart provides the outages (number and duration) for 2012 through 2015 by cause code.

Outages by Cause Code		2012	2013	2014	2015
Unknown - Code #0	# of customers affected	8,387	4,857	91	188
	# customer mins of interruption	24,270	124,889	7,085	9,386
Scheduled Outage - Code #1	# of customers affected	1,713	805	2,345	599
	# customer mins of interruption	102,166	41,552	72,164	38,258
Loss of Supply - Code #2	# of customers affected	16,251	25,384	-	5,500
	# customer mins of interruption	213,453	979,963	-	33,000
Tree Contact - Code #3	# of customers affected	1	22	103	72
	# customer mins of interruption	105	1,800	7,215	2,835
Lightning - Code #4	# of customers affected	2,873	5,719	41	10,223
	# customer mins of interruption	79,312	356,078	5,100	51,967
Defective Equipment - Code #5	# of customers affected	3,186	10,557	4,604	8,527
	# customer mins of interruption	109,329	286,488	154,143	74,318
Adverse Weather - Code #6	# of customers affected	2,015	5,071	14,622	209
	# customer mins of interruption	5,400	442,156	612,671	17,578
Adverse Environment - Code #7	# of customers affected	-	-	47	5,408
	# customer mins of interruption	-	-	6,580	471,560
Human Element - Code #8	# of customers affected	2,900	14	-	-
	# customer mins of interruption	17,400	112	-	-
Foreign Interference - Code #9	# of customers affected	12,794	619	3,512	13,321
	# customer mins of interruption	154,328	44,395	107,101	517,536

b) Brantford Power (BPI) has forecast projects in two investment categories that will impact outages caused by defective equipment.

   a. **System Renewal Investment Category projects** – The rebuild and replacement projects in the 2016 to 2021 period will impact outages that could be caused by defective equipment by proactively replacing equipment before in-service failure.

   b. **System Service Investment Category projects** – The Downtown Automation and Automated Reclose Switches projects in the 2016 – 2021 period will impact outages that could be caused by defective equipment that fails while in-service. Both of these projects have the capability to reduce the number of customers impacted by an outage if the defective equipment that fails is located downstream of the automated reclose switch.

IR: 2.0 – VECC -12

Reference: E2/Attachment A – DSP/pg. 26

a) Please provide a table showing the project, cost and start date and in-service date for all capital programs required as part of the completed IRRP Report.

Response:

Table 2-VECC-12 below shows the projects, project cost, project start date and project in-service date for each of the recommendations in the completed IRRP Report that require a capital program.

Table 2-VECC-12

Capital Project Required as Part of the IRRP Report Recommendations	Total Project Cost	Project Start Date	Project In-Service Date
Installation of Line Banks	$697,064	April 2014	July 2015
Capital Contribution to HONI (115kV Switches)	$NIL	November 2015	February 2019

IR: 2.0 – VECC - 13

Reference: E2/Attachment A – DSP/pg. 49-

a) Please provide a table which shows for each asset class the asset percentage by condition (i.e. very poor to excellent) and the method by which the condition was determined (inspection, age, sampling, etc.)

Response:

Please see the table below which shows the percentage by condition for each asset class along with the method used to determine the condition.

	Condition				Method	
Asset Class	**Excellent**	**Good**	**Poor**	**Very Poor**	**% by ERL**	**% by CHI**
Pole	67%	27%	5%	1%	4%	96%
Primary Conductor	97%	1%	1%	1%	8%	92%
Secondary Bus	95%	1%	1%	3%	7%	93%
Structure	75%	19%	4%	2%	39%	61%
Switch	92%	5%	2%	0%	20%	80%
Transformer	65%	31%	4%	0%	4%	96%

There are two methods used to determine condition. The Condition Health Index (CHI) method which is based on an actual inspection or testing; and the Estimated Remaining Life (ERL) method with is done for those assets that do not have a CHI. The second method uses the Estimated Service Life (ESL) of an asset type and the present age to determine the ERL. ERL% = (ESL – age)/ESL.

IR: 2.0 – VECC -14

Reference: E2/Attachment A – DSP/pg. 96-

a) Please provide a table showing separately the capital contributions for (i) customer access, ii) municipal relocations, (iii)connection evaluations; (iv) lots and town houses. In separate rows please provide the total capital spending related to each category of contributions.
b) Please explain why contributions for lots & townhomes were not received in 2012 through 2015, but are expected in 2016 and 2017 (see Appendix 2-AA).
c) Please explain how the forecast of contributions for 2016 and 2017 was derived.
d) Please provide the total actual contributions for 2016 to-date by category.

Response:

a) Table 1: Capital Contributions and Capital Spending by Type below shows the breakdown of the capital contributions related to Lots & Townhomes, Municipal Relocations and Connection Evaluations. In its reply to this question, Brantford Power (BPI) has assumed that the term 'customer assess' used in part a) of the question refers to new connections that are not lots & town houses being serviced in a subdivision or development; and not a new commercial, industrial or multi-residential building. BPI notes that for the customer access type, it does not receive any capital contributions. Capital spending for the customer access type will be accounted for in the 'New Services (Roll Ins)' System Access Capital Project identified in Exhibit 2 – Attachment A – DSP, Section 5.4.1.d, Figure 51, page 96. BPI notes that the 'Metering – New Customers' project identified in the above mentioned Figure 51 will include the capital cost of all new meters and metering instrumentation for all new customers.

Table 4: Capital Contributions and Capital Spending by Type

Capital Contribution Type	2017	2018	2019	2020	2021
Lots & Townhomes	($369,528)				
Municipal Relocations	($66,425)				
Connection Evaluations	($43,047)				
Customer Access	0	0	0	0	0
Total Contributions	**($479,000)**	**($479,000)**	**($479,000)**	**($479,000)**	**($479,000)**
Capital Spending by Type	**2017**	**2018**	**2019**	**2020**	**2021**
Lots & Townhomes	$739,250	$783,605	$857,530	$872,315	$295,706
Municipal Relocations	$103,600	$398,490	$152,000	$431,550	$160,000
Connection Evaluations	$936,093	$1,072,674	$977,989	$1,041,887	$1,089,306
Customer Access	$267,585	$305,234	$324,131	$333,128	$95,275

BPI notes that the Total Contributions for 2017 in Table 1: Capital Contributions and Capital Spending by Type was based on the 2016 Total Contributions which was the average Total Contributions over the period from 2012 – 2015. For the 2017 contributions from Municipal Relocations and Customer Evaluations, BPI did estimate these individually. The 2017 Lots & Townhomes value was the value required to have the sum of the three types equal the Total Contributions value.

b) BPI notes that Exhibit 2 – Attachment A – DSP, Figure 69, page 134 identified the total capital contributions received in the years 2012 – 2015. The row from that figure is reproduced in Table 2: Capital Contributions 2012 - 2015 below.

Table 5: Capital Contributions 2012 - 2015

Project	2012	2013	2014	2015
Total Capital Contributions	($605,551)	($713,076)	($331,936)	($308,811)

The capital contributions identified in Table 2: Capital Contributions 2012 - 2015 include contributions for Lots & Townhomes, Municipal Relocations and Connection Evaluatons.

c) BPI derived the 2016 Total Contributions based on the average total contributions in the 2012 – 2015 period. BPI used the same value for the 2017 Total Contributions.

The 2016 and 2017 forecast for the Municipal Relocations was derived from the forecast costs for seven identified City of Brantford or MTO projects. 50% of the cost for each of the following projects was included in the Municipal Relocations contribution value: Relocation – Shellard Lane; Relocates – City/MTO; Relocation – Colborne-Dalhousie-Brant-Icomm Intersections; and three projects whose individual expenditures are below the materiality threshold (Colborne Street – Clarence to Brant; Clarence Street – Colborne to West; and Greenwich Street – sewer rebuild).

The 2016 and 2017 forecast for Connection Evaluations was derived from the average economic amount paid per project in the 2012 – 2015 period multiplied by the average number of projects that paid a connection evaluation contribution in the 2012 – 2015 period.

d) The total contributions by category is:

   a. Lots & Townhomes - $33,000 (accrued for 33 townhomes energized)

   b. Municipal Relocations - $0 (all projects are currently work in progress)

   c. Connection Evaluations - $76,915 (three projects paid for, two of the three are energized)

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Reference: E2/Appendix 2-AA

a) Between 2013 and 2015 BPI capital spending on New Services was on approximately 99k. The 2017 test year shows a forecast of $267k. Please provide the supporting evidence for this above average increase.
b) Please identify the subdivision or developments which support this forecast.
c) Please provide the 2016 forecast of new services (number of services) and the actual do-date.

Response:

a) New Services (Roll Ins) evidence is provided below. Table 1: Roll In Historical, Bridge and Test Year Data, shows the amount of capital spending and number of roll in service orders closed by year from 2013 to 2015, 2016 actual values through June 30, 2016, 2016 year end forecast values and 2017 forecast values.

Table 6: Roll In Historical, Bridge and Test Year Data

Year	Capital Spending	Roll Ins	Type
2013	$92,219	208	Actual Values
2014	$76,965	219	Actual Values
2015	$127,577	301	Actual Values
2016	$45,152	115	June YTD Actual
2017	$267,585	325	Budget Forecast
Total Roll Ins		**1353**	

Roll Ins do not necessarily happen the same year that a subdivision or townhouse complex is energized from the high voltage distribution system. The homes or townhouse units will be electrically serviced at the secondary distribution voltage as the homes and townhouse units are constructed. This secondary distribution voltage servicing is referred to as a Roll In. Table 2: Development Construction 2012 - 2017 identifies the developments that were (or are forecast to be) energized from the high voltage system in the period from 2012 to 2017. The lots and units energized during this period is larger than the Roll Ins completed or forecast to be completed in the same period.

Table 7: Development Construction 2012 - 2017

Development Name	Year	Lots/Units
Wyndfield Phase 2A & 2B	2012 – 2013	212
Wyndfield Phase 3	2013 – 2014	185
Wyndfield Phase 4	2014 – 2015	232
Harding Gardens	2014 – 2015	55
Wyndfield Phase 5	2015 – 2016	80
Heatherington Heights	2015 – 2016	33
Wyndfield Phase 6A	2016 - 2017	198
Wyndfield Block 130	2016	36
Park Street North Condos	2016	12
242 Mount Pleasant Rd. Condos	2016 - 2017	18
41 Garden Ave. Condos	2016 - 2017	21
89 Garden Ave. Pinevest Homes	2016 - 2017	4
Wyndfield Phase 6B	2017	273
Wyndfield Phase 7A,	2017	59
Grey & Garden	2017	24
105 Garden	2017	100
Total Lots/Units Energized		**1542**

b) The developments which support the Roll In values and forecast are noted in Table 2: Development Construction 2012 - 2017 shown above.

c) The 2016 year to date Roll In values are shown in Table 3: 2016 Roll Ins Year to Date Values below.

Table 8: 2016 Roll Ins Year to Date Values

Year	Capital Spending	Roll Ins	Type
2016	$59,787	154	Jan. 1 – Jul. 31, 2016 Actual Values

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Reference: E2/Appendix 2-AA

a) The annual spending on vehicles between 2015 and 2017 is almost three times the average annual spending between 2012-2014. Please explain why?

Response:

Brantford Power (BPI) has identified the following useful lives for various types of vehicles.

Vehicle Description	Useful Life Value
Trucks, Bucket Trucks - Large	13 years
Trucks, Bucket Trucks - Small	10 years
Pickup Trucks, Vans, Cars, Other	8 years
Trailers	20 years

BPI uses the useful life as a guide for vehicle replacement. When the vehicle condition indicates that the vehicle can remain in service, the vehicle stays in service. Conversely, a vehicle may become expensive to service before it has reached its ideal useful life point. That vehicle would be replaced earlier than planned.

In the period from 2012 to 2014, the following vehicles were replaced.

Year of Replacement	Vehicle Description	Year of Purchase	Remaining Useful Life When Replaced	Total Yearly Replacement Cost
2012	Truck - Small	2002	0 years	$123,836
2013	Van	2003	-2 years	$176,849
	Pickup Trucks	2003	-2 years	
	Small Truck	2000	-5 years	
2014	Van	2004	-2 years	$118,017
	Van	2002	-4 years	
	Pickup Truck	1999	-7 years	

During the period from 2012 to 2014 BPI replaced vehicles that had for the most part, exceeded their useful life point.

In the period from 2015 to 2017, the following vehicles were replaced or are forecast to be replaced.

Year of Replacement	Vehicle Description	Year of Purchase	Remaining Useful Life When Replaced	Total Yearly Replacement Cost
2015	Bucket Truck – Large	2001	-1 year	$399,909
	Van	2008	1 year[1]	
2016	Bucket Truck – Small	2006	0 years	$400,000 Budget Amount
	Van[2]	2008	0 years	
2017	Bucket Truck - Large	2004	0 years	$425,000 Budget Amount

In 2015, BPI replaced one vehicle that had exceeded its useful life and one vehicle that had become too expensive to repair.

In 2016, BPI will replace two vehicles that had reached their useful life. BPI notes that the van being replaced in 2016 is similar to the van replaced in 2015 and is exhibiting the same repair issues as the one replaced in 2015.

In 2017, BPI will replace a vehicle that has reached its useful life and becoming too expensive to repair.

BPI notes that the large bucket trucks are long delivery items and require 13 to 15 months to construct and deliver after the purchase order has been issued.

The next table shows all the vehicles in the BPI fleet by type and year of purchase. BPI attempts to have the vehicles of each type spread in age across the useful life range. This is done to ensure that there is some flexibility to smooth the replacement of each type through a 12 to 14 year period.

BPI notes that it is entering a period where a number of the relatively more expensive vehicles will be required to be replaced.

[1] Vehicle's frame rusted beyond repair.

[2] Vehicle's frame shows advanced signs of corrosion from rust.

BPI has the following vehicles in its current fleet.

Vehicle Description	Year of Purchase	Number of Vehicles	Total by Type
Trucks, Bucket Trucks – Large	2015	1	4
	2009	1	
	2007	1	
	2004[3]	1	
Trucks, Bucket Trucks – Small	2012	1	6
	2011	1	
	2010	1	
	2008	1	
	2006[4]	1	
	2005	1	
Pickup Trucks, Vans, Cars, Other	2015	1	13
	2014	3	
	2013	4	
	2010	2	
	2008[5]	1	
	2006	2	
Trailers	2010	1	10
	2007	1	
	2005	1	
	1998	1	
	1991	2	
	1990	1	
	1982	1	
	1973	1	
	1964	1	

[3] Being Replaced in 2017

[4] Being Replaced in 2016

[5] Being Replaced in 2016

IR: 2.0 – VECC - 17

Reference: E2/Attachment A – DSP/Appendix 13 & E4/T2/S1/pgs.7-

a) In addition to CIS, FIS, OMS projects Util-Assist identified over 20 projects to improve processes and productivity (see page 137). Please provide a table which lists all the projects identified, indicates whether BPI intends to implement the recommendation, gives the in-service time of that project and the total project cost (please identify capital separately from OM&A).

b) Please also show the quantum of savings expected by implementing each project.

Response:

a) In April 2013, the BPI Board of Directors approved the engagement of Util-Assist to conduct a System Integration Study (SIS). The System Integration Study was designed to review BPI's data requirements, systems and operations to recommend integration plans that will result in significant improvements to the organization's operational efficiencies. This study anticipated a number of deliverables including:
   - Guiding principles for the Systems Integration Study and future integration efforts;
   - Productivity measures to assess and evaluate the feasibility of integration options;
   - Inventories of data, databases, systems and work flows as are required to complete the systems integration study;
   - A gap analysis identifying opportunities for improvement and/or consolidation of processes, systems and data as well as new system requirements as well as an assessment of the risks resulting from not making improvements;
   - A strategy to move toward appropriate functional integration;
   - Implementation plans to achieve integration within three or five year time horizons;
   - A decision-making and business process framework to support implementation of integration efforts.

Throughout 2013, Util-Assist conducted numerous meetings and workshops with various BPI Departments, the City of Brantford's IT Department, BPI system vendors and other parties necessary to fulfill the mandate of the study. Util-Assist issued their interim report on September 13, 2013 with their final report issued to Management on November 22, 2013. Following the review of the findings by BPI's Senior Leadership Team, Util-Assist presented their findings to the Expanded Senior Leadership Team as part of the Management Retreat agenda held on January 23 & 24, 2014. Their findings identified over 20 individual projects necessary to achieve the future state of system integration.

The following table summarizes the specific projects identified in the study. The last column of the table also identifies BPI's intent to implement the system:

Brantford Power Inc.
2013 Systems Integration Study
Summary of Util-Assist Recommended Projects

System	Project ID	Project	SIS report Page #	Status / BPI intent to implement
AMI	A1	Proof of concept: ESM meters	56	Complete
AMI	A2	Proof of concept: remote disconnect meters	58	Future – business case to be developed. BPI intends to evaluate this after completing the implementation of FIS, CIS and WFM systems
AMI	R1	Define department vision statements, including ownership of systems, data, and interfaces	61	Complete
CIS	C1	Begin a CIS procurement	65	BPI intends to implement. CIS procurement underway and expect to implement in 2017
CIS	C2	Implement service order integration	68	Completed for Daffron CIS. Will need to be developed again in the new CIS project
CIS	C3	Implement Workforce Management (WFM)	71	BPI intends to implement a WFM system in 2018 after CIS is completed
DESS	G1	Integrate GIS with ODS (Integrate systems to communicate the "as-designed" connectivity model)	74	BPI has implemented this partially and intends to evaluate this further as part of integrations project in 2019 after all systems are implemented
DESS	G1	Integrate DESS with ODS (Integrate systems to communicate the "as designed" connectivity model)	74	BPI intends to implement this as part of the Integrations project in 2019
ESB	E1	Implement an Enterprise	78	BPI intends to evaluate

System	Project ID	Project	SIS report Page #	Status / BPI intent to implement
		Services Bus (ESB)		ESB and compare to alternatives such as the current point-to-point interfaces and assess which alternative will address BPI needs at the lowest possible cost. BPI has included in its plan an ‘Integrations’ project in 2019 which will build the required integration across systems (either with or without an ESB tool)
FIS	F1	Procure a Financial Information System (FIS)	85	BPI has already procured the FIS system and implementation is underway – expected to go-live by December 31, 2016
GIS	G1	Integrate CIS with GIS (Integrate systems to communicate the “as-designed” connectivity model)	74	Completed for Daffron CIS. Will need to be developed again in the new CIS project
GIS	G1	Integrate GIS with ODS (Integrate systems to communicate the “as-designed” connectivity model)	74	BPI has implemented this partially and intends to evaluate this further as part of integrations project in 2019 after all systems are implemented
MV90	M1	Make ODS the source of metering data, and move GS meter data into the ODS	91	Complete. All metering data has been moved to ODS however BPI has made a business decision to use MDM/R as the source of metering data for billing (and not the ODS). The ODS is used to support and reconcile

System	Project ID	Project	SIS report Page #	Status / BPI intent to implement
				the MDM/R data for the residential and GS<50 customers. The MDM/R is the source of all of this data.
ODS	O1	Integrate the AMI and the ODS	94	Complete
ODS	O2	Enhance VEE processes	95	Future - BPI will review this in the future. Util-Assist report has also identified this project as lower in priority and one that would yield maximum benefit only after all the other systems changes are completed.
ODS	O3	Implement “OMS Lite” / OMS	97	BPI intends to implement an Outage Management System (OMS) in 2017. BPI will deploy “OMS Lite” in 2016.
SCADA	G1	Integrate systems to communicate the “as designed” connectivity model	74	BPI has implemented this partially and intends to evaluate this further as part of integrations project in 2019 after all systems are implemented
SCADA	G2	Integrate systems to communicate the “as operated” connectivity model	103	BPI has implemented this partially and intends to evaluate this further as part of integrations project in 2019 after all systems are implemented
TAPS	C3	Implement Workforce Management (WFM)	71	BPI intends to implement WFM in 2017
WEB	W1	Implement e-billing	107	Complete

System	Project ID	Project	SIS report Page #	Status / BPI intent to implement
WEB	W2	Implement Web presentment of TOU data	108	BPI intends to implement TOU web presentment in 2017
UEM	U1	Build Asset Management vision and implement enabling integration	110	Future – BPI will review this after implementing the FIS and WFM systems and incorporate the required integrations through the Integrations project in 2019.

Cost of the above identified projects is identified in the table below:

Project name	Total budget	2016	2017	2018	2019	2020
FIS	**$2,458,903**	**$1,624,335**	**$289,642**	**$181,642**	**$181,642**	**$181,642**
Capital	$845,907	$845,907				
Operating	$1,612,996	$778,428	$289,642	$181,642	$181,642	$181,642
CIS	**$3,333,218**		**$2,178,286**	**$426,718**	**$363,312**	**$364,903**
Capital	$682,149		$682,149			
Operating	$2,651,069		$1,496,137	$426,718	$363,312	$364,903
OMS (Outage Management)	**$448,951**	**$31,029**	**$374,511**	**$14,470**	**$14,470**	**$14,470**
Capital	$239,904		$239,904			
Operating	$209,047	$31,029	$134,607	$14,470	$14,470	$14,470
TOU web presentment	**$261,962**		**$172,298**	**$29,291**	**$29,882**	**$30,492**
Capital						
Operating	$261,962		$172,298	$29,291	$29,882	$30,492
WFM (Workforce Management)	**$114,063**			**$101,563**	**$6,250**	**$6,250**
Capital	$57,188			$57,188		
Operating	$56,875			$44,375	$6,250	$6,250
Additional integrations (INT)	**$396,200**				**$396,200**	
Capital	$396,200				$396,200	
Operating						
Total	**$7,013,297**	**$1,655,363**	**$3,014,737**	**$753,683**	**$991,756**	**$597,757**
Total Capital	**$2,221,348**	**$845,907**	**$922,053**	**$57,188**	**$396,200**	
Total Operating	**$4,791,949**	**$809,456**	**$2,092,684**	**$696,496**	**$595,556**	**$597,757**

See Table 4.2F : SIP – Normalization of implementation and OM&A costs in Exhibit 4, Tab

2, Schedule 1 (page 14 of 20) on how the OM&A costs above have been normalized over the five years from 2017 to 2021.

b) Below table outlines the summarized business case for each project. In most cases, BPI does not see cost savings as a key driver for implementing a technology solution but the reduction in risk levels that BPI and its business is currently exposed due to the delays, lack of information and other challenges in existing systems.

Project name	Business case / savings expected
FIS	BPI has never invested in a financial system and relied on the City systems to carry along the operations. This investment and the on-going costs to maintain will bring greater control and ownership over the FIS solution by BPI and BPI's ability to respond and report to its various stakeholders. Some savings are expected in the service level agreement (SLA) costs that BPI currently pays to the City but these are marginal, since the current City systems have been stable with minimal changes. These costs are expected to bring productivity gains in the longer run but are difficult to quantify. It is not practicable to measure all the benefits in monetary terms. A lot of the benefits will be in terms of better timing of information, more time to perform meaningful analysis, greater confidence in the numbers/information from the system and better service/visibility to the internal and external business stakeholders/ consumers of financial information.
CIS	BPI investment in CIS is expected to bring a number of opportunities by creating a foundational customer service platform that is well supported, incorporates best practices in the Ontario LDC market and allows BPI the systems flexibility and nimbleness to adapt to changes in the environment (regulatory, customer service driven, competitive etc.). Current key gaps: - BPI uses the Daffron CIS Version 5 which is over 25 years old, highly customized and at risk of running out of vendor support. - current Daffron platform does not easily support "a 'robust' customer care engagement package", including the integration with proposed peripheral services (such as e-services) without extensive vendor and internal customization. A number of Ontario LDCs that used Daffron have migrated to other CIS platforms due to this reason (compounding the risk of in #i above) - current Daffron system is not intuitive or easy to use/learn, does not use a graphical user interface (GUI) and requires a high level of support (higher effort and costs to maintain/upgrade/enhance/modify) than some of the alternatives in the market that use a more current technology platform As a result of the above, BPI currently requires longer timelines and

Project name	Business case / savings expected
	greater effort to modify the current Daffron system and test the system for changes (example, programs such as OESP, removal of debt retirement charge, clean energy etc.). Any changes due to regulatory or environmental changes (that impact all LDCs in the Ontario LDC market) need to be programmed into the current Daffron CIS system by BPI's Daffron programmers; BPI is unable to avail of software vendor supplied updates in a timely manner (primarily due to the older version / current vendor updates). Investment in a new CIS is expected to allow BPI to adopt a system that is more commonly used in the Ontario market and avail of updates/releases from the vendor at least for some, if not all, updates. BPI can gain better confidence and reduce the risk of an unsupported system. Further, BPI may be able to avail opportunities to collaborate with other Ontario LDC/s on the same CIS platform and share system wide best practices and potentially share costs of changes where such changes are required for all such LDC/s. BPI expects approximately $100,000 to $150,000 in annual savings starting 2018 on the service level agreement (SLA) costs that BPI currently pays to the City for Daffron support. In addition, the new CIS system is expected to bring a number of benefits, which are difficult to quantify, such as: • qualitative benefits outlined above, • reduced development costs to meet regulatory/industry requirements • reduced foreign exchange risk as current Daffron support charges are in US dollars • productivity gains in the longer run
OMS	Currently, BPI does not have a robust OMS system and tracks outages in an old MS Access database by recording outages after the fact. The database and reporting has significant limitations on being able to track the exact impact of the outage and customers impacted. BPI hence operates with delayed/partial information on outages. This limits BPI's ability to proactively respond and manage outages, including communication to customers. An OMS is expected to allow BPI to be more proactive, address outages and provide information to impacted customers on outages and status. OMS is not expected generate significant cost savings but instead improve operations, timely reporting and improved/timely communication to customers/field staff.
TOU Web presentment	Currently, customers do not see TOU data used in the calculation of their bills, although this data is being used by the Daffron CIS to

Project name	Business case / savings expected
	calculate the billing. Making this data available to customers allows them to understand usage pattern and manage usage, conserve energy and save on their bills. • A number of LDCs in Ontario are already offering TOU web presentment. Brantford Power would like to offer similar or better information (and services) to BPI customers. • OEB had required electricity distributors in the province to submit a plan for web presentment of TOU information to customers and this initiative furthers that plan. BPI investment in TOU is expected to bring a number of opportunities: - BPI customers can get direct access to the TOU information on which their bill is based, monitor - BPI customers can manage their consumption based on information on their past/current usage including on/off peak usage - potentially reduce inquiries from customers through phone / email for TOU related information/data - place BPI on par with other Ontario LDCs and - allow compliance with OEB requirements to present TOU information on web for customers to view and monitor Currently, BPI does not have this service/ feature offered to BPI customers. Of the above opportunities, the potential reduction in inquiries for TOU information may be the only one that could result in some productivity gains. However, it is difficult to estimate what percentage of the customer base will avail of the service and whether there will indeed be a real reduction in number of inquiries. These inquiries may be replaced by other types of inquiries like customers wanting to understand the graphs/charts and information presented through TOU web presentment.
WFM	Currently, BPI does not have a WFM system and manages field service through paper orders. Util-Assist has outlined the key issues in the current manual environment like a manual keypunch process into CIS and likelihood of errors. Util-Assist has also outlined a number of benefits of moving to an automated WFM system. BPI investment in WFM is expected to bring a number of opportunities such as: • Eliminating the need to handle paper service orders • Eliminating the delays in getting information returned into the CIS • Reducing the error-correction process that results from keypunch errors

Project name	**Business case / savings expected**
	• Reducing the "mundane" tasks associated with many daily processes • Paper management; currently, significant resource time is involved in filing paper service orders in the event they are required for future reference. • Storing service order information for update once billing completes • Improved work assignment; automated WFM systems generally include mapping of work, allowing the dispatcher a geographic view of service/work orders and a more efficient distribution of field work • Safety considerations; automated WFM systems allow "configuration" of employees and vehicles within the system which can prevent orders from being assigned to the people or vehicles that are not able to safely perform the work due to lack of certification or tools. In addition to this work assignment safety consideration, the ability to track locations of crews provides added safety - the BPI Operations team has cited location tracking as a goal to improve safety in such situations as feeder breaker "hold off" situations. • Form management; as well as service orders, crews can complete predefined forms in the WFM which can be used to populate information into other downstream systems such as payroll, or for tracking MTO drive time information. WFM is not expected generate significant cost savings but instead improve operations, timely reporting and improved/timely communication to customers/field staff.
Additional integrations (INT)	Currently, BPI does not have appropriate levels of integration across systems requiring manual effort, reconciling data from different systems or in some cases incomplete data available for analysis. Primary driver for this initiative is to connect the data across systems so there is sharing of information electronically across systems and ability to obtain a harmonized or comprehensive view of information across systems. BPI investment in INT is expected to bring a number of opportunities such as: • Reporting on transformer (Tx) loading for improved asset management • Reporting on voltage to satisfy the "due diligence" to ensure "conditions of service" are maintained • Improved outage/restoration processes through either the ODS (i.e., current capability), or the OMS (i.e., future system) • Work order integration to FIS to feed in financial information electronically on costs relating to work orders and avoid manual

Project name	**Business case / savings expected**
	upload with potential for delays and/or errors • Work order information to ODS to allow reporting of work orders and status against each transformer, meter and other assets INT is not expected generate significant cost savings but instead improve operations, timely reporting and improved/timely communication to customers/field staff through consistent and complete information across systems.

Exhibit 3: Operating Revenues

IR: 3-Staff-36

Ref: Exhibit 3, Tab 2, Schedule 2, pgs. 1 and 3

Brantford Power states that the monthly flag variables control for seasonal variability in power purchases during the spring and fall months. The prediction model outline lists an April flag and a May flag.

a) Please explain how variability in fall power purchases has been explained in the model.

Response:

Variability in fall power purchases has not been explained in the model.

Although BPI makes reference to monthly flags for power purchases during the spring and fall months, the monthly flag for October was found to be less statistically significant and removed which is why the prediction model outline lists only an April and May flag. October was removed during the final run of the regression model however the written evidence was not adjusted to reflect that BPI only included the spring monthly flags.

The chart below compares the statistical data including and excluding the October flag.

	Excluding October	Including October
Regression Statistics		
Multiple R	0.913029826	0.915179893
R Square	0.833623463	0.837554237
Adjusted R Square	0.823224929	0.825846434
Standard Error	2734371.825	2714021.261
Observations	120	120
ANOVA (df)		
Regression	7	8
Residual	112	111
Total	119	119
Coefficients		
Intercept	-29865741.66	-34545160.4
Heating Degree Days	16419.90774	15463.77862
Cooling Degree Days	125379.6434	118828.2867
Ontario Real GDP Monthly %	368436.2998	374950.4142
Number of Days in Month	1795333.391	1942863.101
apr	-3839799.44	-4178034.56
may	-2806041.255	-3322881.791
oct		-1702011.222
Negative Impact Variable	-2.738072966	-2.757485684
t-Stat		
Intercept	-1.567806688	-1.806568605
Heating Degree Days	11.35501743	9.980976518
Cooling Degree Days	15.51432654	13.25871
Ontario Real GDP Monthly %	3.032454425	3.107522364
Number of Days in Month	5.590111108	5.865447853
apr	-4.01497218	-4.300917553
may	-2.834158585	-3.219620837
oct		-1.638877001
Negative Impact Variable	-6.772654624	-6.868823745

IR: 3-Staff-37

Ref: Exhibit 3, Tab 2, Schedule 2, pg. 3

Brantford Power states that the Negative Impact Variable reflects the impact of CDM on the load forecast, as well as the impact of economic conditions in the service area. The model also incorporates Real Ontario GDP.

a) Please explain how economic effects are explained by the model, when the derivation of the variable on page 4 of the evidence appears to reflect only CDM savings.
b) Please explain why multiple variables are required to reflect economic conditions.

Response:

a) The statement "The Negative Impact Variable…" in Exhibit 3, Tab 2, Schedule 2 page 3 at row 17 was misstated. Economic effects are explained by the GDP variable in the model. The negative impact variable represents only CDM savings
b) As per the response to a) above, BPI has not used multiple variables to reflect economic conditions.

IR: 3-Staff-38

Ref: Exhibit 3, Tab 2, Schedule 2, pg. 3

OEB staff notes that customer numbers have not been included in the model.

a) Please explain why customer numbers (or other customer growth variables) have not been included in the model.

Response:

As BPI was developing its Load Forecasting model, a model was tested using 2015 part-year data which included a customer numbers variable, consisting of the customer number in the residential, GS<50 and GS>50 classes. While the model was statistically significant, the coefficient of this variable was negative, which is a non-intuitive relationship. As customer numbers grow, power purchases are expected to also grow.

IR: 3-Staff-39

Ref: Exhibit 3, Tab 3, Schedule 1, pg. 5

Brantford Power states that it had significantly increased disconnection notices in 2015.

a) Please explain why.
b) What actions has Brantford Power taken to address this issue

Response:

a) In 2015, there was a greater focus on managing bad debt as a result of the 2013 MEARIE which indicated that BPI was lagging behind industry standard in this measure.

b) The increase in disconnections, as noted above, is related to BPI's focus on collections activities rather than on changing customer behavior.

BPI complies with the OEB's rules for low-income customers (for example, the provision of an Arrears Management Program) and works actively to promote the LEAP and OESP programs with social agencies and community partners. BPI has a practice not to send notices or perform disconnections during periods of extreme weather such as during extended heat or cold alerts. All of this is in addition to individual efforts by Customer Service and Collections staff to assist customers. However, like most businesses, BPI must be prudent in its collections processes in order to stay financially viable, including, as a last resort, performing disconnections. Failure to do this would remove a significant disincentive for delinquent customers to pay their bills, would allow the level of outstanding bills to increase, and would result in increases to the bad debt expense included in rates.

IR: 3-Energy Probe-22

Ref: Exhibit 3, Tab 1, Schedule 1

Table 3.1-A shows revenue associated with the SSS Administration Charge beginning in the 2016 bridge year.

a) Where was this revenue recorded in previous years?

b) Please show the actual amount of revenue from this source for each of 2013 through 2015.

Response:

a) SSS Administration Charges was included in Distribution Revenues in Historical years as stated in Exhibit 3, Tab 1, Schedule 1, pg. 2.
b) As stated in Table 3.1-A, below is the actual amount of revenue from SSS Administration Charge from 2013 through 2015.

2013	2014	2015
$106,572	$108,547	$111,559

IR: 3-Energy Probe-23

Ref: Exhibit 3, Tab 2, Schedule 1

Please provide the "statistically weak results" of the regression analysis based on the individual rate classes noted on page 1. Please provide the regression analysis and data used in a live Excel spreadsheet.

Response:

The statement at line 22 of E3/T2/S1 "In attempting to use the method suggested, BPI found it produced statistically weak results." should have read "In attempting to use the method suggested ***in the past***, BPI found it produced statistically weak results." BPI did not attempt to use this method for the current application.

These trials were completed early in the load forecast design process for the 2013 COS, however, they produced results with R-Squared results in the 20-30% range for the residential forecast, and 30-40% for the General Service Greater than 50 rate Class and GS less than 50 kW rate classes.

IR: 3-Energy Probe-24

Ref: Exhibit 3, Tab 2, Schedule 2

Please confirm that the negative impact variable is, in fact, calculated based on CDM only, as shown in the Negative Impact Var tab of the forecasting model.

Response:

BPI confirms the negative impact variable is calculated based on CDM only.

IR: 3-Energy Probe-25

Ref: Exhibit 3, Tab 2, Schedule 2

Please show the derivation of the figure of 18,155,410 for net kWh savings in 2017 from 2015 to 2017 CDM programs based on the figures shown in Table 3.2-Q.

Response:

The figures shown in Table 3.2-Q represent the full years savings while the 18,155,410 represents expected actual savings applying the half year rule. The chart below shows the calculation.

	2015	2016	2017	Total
Full Year Savings	5,239,000	7,730,072	15,611,676	28,580,748
Multiplication Factor	50%	100%	50%	
Expected Actual Savings	2,619,500	7,730,072	7,805,838	18,155,410

IR: 3-Energy Probe-26

Ref: Exhibit 3, Tab 2, Schedule 2

a) For each of the three rate classes shown in Table 3.2-V please estimate a regression equation where the dependent variable is the kW/kWh ratio and the dependent variable is a trend variable.

b) For each of the regression equations estimated in part (a) that has a statistically significant coefficient on the trend variable, please provide the regression statistics and calculate the forecast for 2017 for the kW/KWh ratio.

c) Based on the kW/kWh ratio calculated in part (b) above, what is the impact on the kW forecast for the 2017 test year shown in Table 3.2-W?

d) Based on the change in the kW forecast noted in part (c) above, what is the impact on the revenue deficiency in the test year?

Response:

a) As requested, for each of the three rate classes shown in Table 3.2-V BPI has estimate a regression equation where the dependent variable is the kW/kWh ratio and the independent variable is a trend variable.

b) The regression statistics for each of the classes are provided below. BPI has included the Streetlight results below as well as in the subsections below, however the coefficient for the trend variable in that class is <u>not significant.</u> The forecast for the 2017 kW/KWh ratio is shown in the answer to part c).

GS>50		
Regression Statistics		
Multiple R	0.93298504	
R Square	0.870461085	
Adjusted R Square	0.85426872	
Standard Error	3.84934E-05	
Observations	10	
ANOVA		
	df	
Regression	1	
Residual	8	
Total	9	
	Coefficients	*t Stat*
Intercept	0.0024042	91.4282486
Trend Variable	3.10727E-05	7.331950862

Sentinel		
Regression Statistics		
Multiple R	0.782211412	
R Square	0.611854692	
Adjusted R Square	0.514818365	
Standard Error	4.24579E-05	
Observations	6	
ANOVA		
	df	
Regression	1	
Residual	4	
Total	5	
	Coefficients	*t Stat*
Intercept	0.003178867	80.42432127
Trend Variable	-2.5486E-05	-2.51105932

Streetlight		
Regression Statistics		
Multiple R	0.01031952	
R Square	0.000106492	
Adjusted R Square	-0.1248802	
Standard Error	5.65766E-06	
Observations	10	
ANOVA		
	df	
Regression	1	
Residual	8	
Total	9	
	Coefficients	*t Stat*
Intercept	0.0030556	790.5993281
Trend Variable	1.81818E-08	0.029189564

c) Based on the kW/kWh ratio calculated in part (b) above, the chart below shows the impact on the kW forecast for the 2017 test year shown in Table 3.2-W.

2017	**GS>50**	**Sentinel**	**Streetlight**
Weather Normal kWh's forecast (Table 3.2-T)	477,408,179	413,902	7,460,329
kW/kWh ratio as per regression	0.2777%	0.2975%	0.3056%
Calculated kWs	**1,325,797**	**1,231**	**22,797**
Reported in Application	1,251,277	1,291	22,657
Difference	**74,520**	**(60)**	**140**

d) Based on the change in the kW forecast noted in part (c) above, the impact on the revenue deficiency in the test year is a decrease of $277,316.44 including all three classes.

2017	**GS>50**	**Sentinel**	**Streetlight**	**Total**
Change in kWs	74,520	(60)	140	74,601
Current volumetric rate	3.0605	19.4167	2.8877	
Impact to Revenue Deficiency	**(228,069.18)**	**1,158.20**	**(405.46)**	**(227,316.44)**

IR: 3-Energy Probe-27

Ref: Exhibit 3, Tab 2, Schedule 2

a) Please rerun the regression analysis using the model as filed, with the addition of trend variable as an explanatory variable (i.e. value of 1 in the first month, 2 in the second month, and so on). Please provide the regression statistics and forecast for the 2017 test year, as well as the Excel spreadsheet that would replace the forecast model if the new equation was used.

b) What is the resulting impact on the revenue deficiency if the equation that includes the trend model is used?

Response:

a) BPI has rerun the regression analysis using the model as filed, with the addition of a trend variable as an explanatory variable (i.e. value of 1 in the first month, 2 in the second month, and so on). The regression statistics are shown below and the forecast purchases for the 2017 test year are 943,711,190. As well, the Excel spreadsheet that would replace the forecast model if the new equation was used has been provided as Attachment 3-EP-27.

Please note that BPI had previously used a trend variable in one of the trials and observed that the resulting predicted purchases were not in line with expectations. Compared to the original application, the predicted purchases using the trend variable are 19 million kWhs higher.

Regression Statistics		
Multiple R	0.96333506	
R Square	0.928014438	
Adjusted R Square	0.922826289	
Standard Error	1806682.142	
Observations	120	
ANOVA		
	df	
Regression	8	
Residual	111	
Total	119	
	Coefficients	*t Stat*
Intercept	-79758410.49	-6.020185002
Heating Degree Days	16631.03931	17.40361479
Cooling Degree Days	126822.6742	23.74486429
Ontario Real GDP Monthly %	762921.67	8.801473191
Number of Days in Month	1789820.588	8.434505829
apr	-3800134.672	-6.013716179
may	-2750237.218	-4.204024255
Negative Impact Variable	-1.213402131	-4.106137154
Trend Variable	-141484.9389	-12.06435271

b) The chart below shows the resulting impact on the revenue deficiency if the equation that includes the trend model is used.

2017	Residential	GS<50	GS>50	Sentinel	Streetlight	USL	Total
Billed kWh's as per original application	299,914,722	102,713,003	484,599,496	382,297	7,460,329	1,405,154	896,475,001
Billed kWh's as per original application	291,567,897	99,837,652	477,408,179	382,297	7,460,329	1,405,154	878,061,508
Change in kWh's	8,346,825	2,875,351	7,191,317	-	-	-	18,413,493
kW/kWh ratio			*0.2575%*	*0.3090%*	*0.3056%*		
Change in kW's			18,518	-	-		18,518
Current volumetric rate	$ 0.0110	$ 0.0069	$ 3.0605	$ 19.4167	$ 2.8877	$ 0.0076	
Impact to Revenue Deficiency	**(91,815)**	**(19,840)**	**(56,673)**	**-**	**-**	**-**	**(168,328)**

IR: 3-Energy Probe-28

Ref: Exhibit 3, Tab 3, Schedule 1

Please provide a version of Table 3.4-A (only that portion found on page 1) that reflects the removal of CDM related revenues (account 4375) and costs (account 4380) in all the years shown. If applicable, please also remove any revenue or costs associated with interest on regulatory assets (deferral and variance accounts) included in account 4405.

Response:

Please see Table 3-EP-28 below for the version of Table 3.4-A which reflects the removal of CDM related revenue and expenses, and revenue/expenses associated with interest on regulatory assets. BPI notes that its original Application incorrectly included these items as part of revenue offsets. BPI's responses in 1-Staff-1 b) remove the impacts of interest on regulatory assets and CDM related costs and revenues.

Table 3-EP-28

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	-$ 496,272	-$ 506,195
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	-$ 15,000	-$ 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	$ -	-$ 85,811	-$ 85,811	-$ 410,229	-$ 415,250	-$ 1,016,302
4380	Expenses from Non-Utility Operations	$ 118,500	$ 211,119	$ 211,119	$ 707,218	$ 703,376	$ 892,222
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	-$ 210,520	-$ 173,390	-$ 173,390	-$ 133,246	-$ 156,337	-$ 132,986
4415	Equity in Earnings of Subsidiary Companies	$ -	$ -		$ -	$ -	$ -
Specific Service Charges		-$ 441,756	-$ 539,109	-$ 539,109	-$ 650,019	-$ 496,272	-$ 506,195
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		-$ 112,200	-$ 68,070	-$ 68,070	$ 68,250	$ 101,789	-$ 287,366
Total		-$ 975,210	-$ 1,093,328	-$ 1,093,328	-$ 1,082,268	-$ 881,941	-$ 1,293,372

IR: 3-Energy Probe-29

Ref: Exhibit 3, Tab 3, Schedule 1

Please provide the year-to-date actual revenues for the most recent period available in 2016 in the same level of detail as the portion of Table 3.4-A on page 1. Please also include the revenues for the corresponding period in 2015. Please exclude all CDM related revenues and costs and any regulatory asset interest, consistent with the table requested in the preceding interrogatory.

Response:

Please see the table below for June 2016 Actuals, and June 2015 Actuals.

Appendix 2-H
Other Operating Revenue

USoA #	USoA Description	2016 Actual June YTD	2015 Actual June YTD
	Reporting Basis		
4235	Specific Service Charges	(279,611)	(300,771)
4225	Late Payment Charges	(125,039)	(110,106)
4080	SSS Revenue	(56,584)	(55,519)
4082	Retail Services Revenues	(28,575)	(25,722)
4084	Service Tax Requests	(10,704)	(4,965)
4090	Electric Services Incidental to Energy Sales	-	-
4205	Interdepartmental Rents	-	-
4210	Rent from Electic Property	(48,391)	(47,833)
4215	Other Utility Operating Income	-	-
4220	Other Electric Revenues	-	728
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	(41,278)	(22,964)
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	-	-
4380	Expenses from Non-Utility Operations	-	-
4385	Expenses of Non-Utility Operations	-	-
4390	Miscellaneous Non-Operating Income	(41,451)	(1,020)
4395	Rate-Payer Benefit Including Interest	-	-
4398	Foreign Exchange Gains and Losses, Including Amortization	-	-
4405	Interest and Dividend Income	(67,198)	(72,135)
4415	Equity in Earnings of Subsidiary Companies	-	-
Specific Service Charges		-$ 279,611	-$ 300,771
Late Payment Charges		-$ 125,039	-$ 110,106
Other Operating Revenues		-$ 144,254	-$ 133,311
Other Income or Deductions		-$ 149,928	-$ 96,118
Total		-$ 698,832	-$ 640,306

IR: 3-Energy Probe-30

Ref: Exhibit 3, Tab 3, Schedule 1

a) Please explain why there is no offsetting revenue in 2016 shown in Table 3.4-A for the $118,939 in account 4380 for new building operational costs – non-utility.

b) Please explain the decline in pole rental revenues other in account 4210 in 2016 and 2017 relative to the previous years.

c) Please explain the significant decrease in revenues from specific service charges forecast for 2016 and 2017 relative to 2015. In particular, please explain what is meant by field connection charge and explain why this is forecast to drop by approximately $150,000 in 2016 and 2017 as compared to 2015.

d) Please explain, including showing all calculations and assumptions used, in the decline in investment income in account 4405 in 2016 and 2017 relative to the average of the previous years shown.

Response:

a) The 2016 projected trial balance does not report this adjustment, as the 2016 trial balance is a reflection of what BPI expects in revenue and expenses for 2016. In 2017,without this adjustment made to offset the expenses for the new operational costs-non utility, account 4380 would have a debit balance, with no offsetting credit amount, which would increase the service revenue requirement by that amount. The adjustment was only done in 2017 as it is the test year, and BPI wanted to ensure this amount was not included in our revenue requirement. As BPI has removed the funding request for the building, and any associated non-utility expenses in relation to the building, BPI has made no equivalent adjustment in the response to 1-staff-1 b).

b) There was a budgeting error where some of the historic actuals for pole rental revenue were not considered when establishing the 2016 and 2017 projections. The correct 2016/2017 revenues should be roughly in line with the 2015 actuals.

c) There was a typo and it is meant to be field collection charges. BPI expected field collection charges to decrease in 2016 because of the Ontario Electricity Support Program (“OESP”), which was put in place to assist low income customers, effective 2016. The year to date actual revenues for June 2016 are $189,930, which is an increase over the original expectation. As a result, BPI increased its expectation for 2016 field collection charges in the updated revenue offsets included with 1-Staff-1.

d) The decline in investment income is as a result of decreasing projected interest from bank balances. This decreased bank balance is a result of funding a component of the building purchase in 2016 through cash in the original application.

The calculation of investment income is as follows: The average bank balance is calculated as the average of the opening and closing bank balance (bank balance is the equivalent of cash and cash equivalents). An assumed bank interest rate of 1.2% is applied on the average bank balance.

BPI notes the investment income in 4405 was incorrectly based on a previous version of the budget. The corrected calculation is set out below:

	2016	2017
Opening Bank Balance	$9,915,249.00	$6,879,228.00
Closing Bank Balance	$6,879,228.00	$9,378,927.00
Average Bank Balance	$8,397,238.50	$8,129,077.50
Interest Rate Applied	*1.20%*	*1.20%*
Expected Interest	$100,766.86	$97,548.93
Interest per budget & Application	$ 149,337.00	$ 125,846.00

BPI has updated its forecast for interest income for 2016 in its response to 1-Staff-1.

IR: 3.0 –VECC -18

Reference: E3/T1/S1, page 1
E8/T5/S4, page 1, Table 8.5-B

a) Please confirm that the revenue at proposed rates set out in Table 3.1-A is actually the proposed revenue allocation to each of the customer classes.

Response:

BPI confirms that the revenue at proposed rates set out in Table 3.1-A is the proposed revenue allocation to each of the customer classes as also shown in E8/T5/S4, page 1, table 8.5-B.

In other words, Table 3.1-A does not include the transformation allowance added to determine the volumetric rates in Table 8.1-G. It is not the revenue at proposed rates since if the proposed rates were used it would reflect transformer allowance amounts.

IR: 3.0 –VECC -19

Reference: E3/T2/S1, page 1 (lines 6-7)
E3/T2/S2, pages 1-5

a) Did Brantford test any other model specifications to determine whether the model and variables used in EB-2012-0109 were still the most appropriate?
b) If yes, what other model specifications and/or variables were tested and what were the results?

Response:

a) BPI did test other model specifications to determine whether the model and variables used in EB-2012-0109 were still the most appropriate.

b) The table below outlines the additional variables tested. BPI notes that these trials were tested throughout the rate application preparation process, so other items, for example more recent actual data, were updated between trials. That is to say, the trials done were not on an “all else equal” basis.

Variable Tested	Reason for Rejecting
Customer numbers – Res and GS<50	T-statistic of 0.5 to 0.71
Spring/ Fall Flag	Individual month indicators had better t-statistics, when they were >|2|
Trend Variable	•Resulting forecasts inconsistent with recent years; •This variable has no real explanation, it is picking up the impacts of other un-represented factors. How do we predict patterns in the future term, if we don’t know what the variable is measuring?
October, September, November Month Variables	t-stat <|2|
Brantford Area StatsCan data for labour force, unemployment, employment, participation rate	•difficult to forecast; •t-stats <|2|

IR: 3.0 –VECC -20

Reference: E3/T2/S2, page 2

a) Please explain why the predicted purchases for 2015 are materially less than those the years immediately prior (e.g. 2014) or immediately after (2016 and 2017).
b) The Table indicates that the 20 year value is based on the 20 year average while the text (line 5) indicates it is based on the 20 year trend in weather data. Please clarify which is the case.
c) If Table 3.2-D is based on the 20 year average in weather data, please provide the results based on the 20 year trend per the Filing Guidelines.

Response:

a) BPI has determined the kWh's impact of each variable on the forecast by multiplying the value of each variable by its coefficient. Using this method the explanations for the year over year variances are discussed in the following paragraphs.

   Predicted purchases for 2015 are less than 2014 primarily due to the full year impact of 2014 CDM results which reduce kWhs in 2015 by (52m). This is offset by increases related to GDP of 16m kWhs and the net impact of heating and cooling degree days of 5m kWhs.

   The predicted kWhs for 2016 are 906m which is not shown in table 3.2-D. The increase from 2015 to 2016 is primarily due to increasing GDP of 17m kWhs, offset by additional CDM savings of (6m) kWhs.

   The increase from 2015 to 2017 is mostly related to increasing GDP, 33m kWhs, offset by small decreases related to CDM and heating/cooling degree days.

b) BPI used the 10 and 20 year average in its load forecast calculations.

The chart below shows the predicted kWh's using the 10 and 20 year trend. The 2016 Bridge year has also been included.

Year	Actual	Predicted	% Difference
2006	1,022.8	990	-3.3%
2007	1,043.0	1,011	-3.2%
2008	1,013.4	991	-2.3%
2009	940.8	955	1.5%
2010	950.8	974	2.4%
2011	944.9	984	4.0%
2012	964.4	985	2.1%
2013	961.3	969	0.8%
2014	913.5	924	1.1%
2015	920.5	893	-3.1%
2016 Bridge Weather Normal - 10 year trend		905	
2016 Bridge Weather Normal - 20 year trend		904	
2017 Test Weather Normal - 10 year trend		924	
2017 Test Weather Normal - 20 year trend		923	

IR: 3.0 –VECC -21

Reference: E3/T2/S2, page 4

a) Has Brantford Power received the report from the IESO on its actual 2015 CDM results? If so, please provide a copy of the Report and update the load forecast model and 2016 & 2017 predictions for power purchases.

Response:

BPI has received the report from the IESO on its actual 2015 CDM results. A copy is provided as Attachment 3-VECC-21. The load forecast model has been updated and the 2016 & 2017 predictions for power purchases are shown in the table below. Please note this update is isolated to only updating for 2015 actual results and does not incorporate any other information from other interrogatories.

	2016	**2017**
As Submitted in Application	905.7	924.7
Updated Based on 2015 Actual CDM Results	901.4	919.5

IR: 3.0 –VECC -22

Reference: **E3/T2/S2, page 4**
Load Forecast Model, CDM Results Tab, Cells T3 to AE11
Exhibit 4, Attachment 4-H, page 12

a) In many instances the savings in the years 2013 and 2014 due to CDM program from each of the years 2006-2014 as set out in the CDM Results Tab do not reconcile with the totals for 2013 and 2014 as set out in the Burman Report (page 12). Please explain why the differences exist and/or correct the tables as necessary.

b) Based on the results of part (a) please revise the load forecast model/projections and the LRAM claim as necessary.

Response:

a) BPI agrees that the savings in the years 2013 and 2014 due to CDM program from each of the years 2006-2014 as set out in the CDM Results Tab do not reconcile with the totals for 2013 and 2014 as set out in the Burman Report (page 12). In consultation with Burman Energy Consultants in order to assess the differences, adjustments were necessary for both the Burman report and BPI's load forecast. The revised Burman report is included as Attachment 3-VECC-22. BPI has adjusted the table in the CDM results tab as follows:

		Results Year											
		2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Program Year	**2006**	2,666,105	2,666,105	2,666,105	2,666,105	463,043	463,043	423,559	423,559	397,999	397,999	376,021	376,021
	2007	0	1,387,120	1,375,497	1,375,497	1,375,497	1,374,565	1,319,406	1,319,449	1,319,406	451,387	311,035	164,898
	2008	0	0	2,696,911	2,083,518	2,083,518	2,083,518	1,953,835	1,952,703	1,818,844	1,718,921	1,280,426	950,424
	2009	0	0	0	6,943,327	6,230,629	6,230,629	6,227,931	6,110,636	5,806,438	5,738,138	5,736,648	4,440,683
	2010	0	0	0	0	4,170,820	2,995,440	2,991,631	2,989,542	2,866,698	2,447,090	2,432,987	2,367,568
	2011	0	0	0	0	0	4,515,774	4,502,851	4,269,480	4,164,655	4,044,925	3,842,745	3,585,982
	2012	0	0	0	0	0	0	5,363,496	5,801,327	5,778,849	5,681,217	5,580,103	5,264,741
	2013	0	0	0	0	0	0	0	6,994,578	6,908,925	6,895,581	6,806,732	6,111,099
	2014	0	0	0	0	0	0	0	0	33,821,560	33,152,890	33,032,221	32,854,801
	2015	0	0	0	0	0	0	0	0	0	7,539,722	7,402,101	7,402,101
	2016	0	0	0	0	0	0	0	0	0	0	7,730,072	7,730,072
	2017	0	0	0	0	0	0	0	0	0	0	0	15,611,676
	Total	2,666,105	4,053,225	6,738,513	13,068,447	14,323,507	17,662,970	22,782,709	29,861,274	62,883,374	68,067,869	74,531,091	86,860,067

Please note that in this chart 2015 has been updated to reflect actual CDM results and persistence numbers for 2015 thru 2017 related to CDM programs from 2011-2014 have also been adjusted based on work done with Burman Energy Consultants in answering this interrogatory.

b) Based on the results of part (a) BPI has revised the load forecast model/projections and incorporated the revisions in the response to 1-Staff-1 b).
The following table shows the updated LRAM claim and rate riders.

Customer Class	2011-2014 CDM Program Lost Revenues in 2014	2014 LRAMVA Baseline	LRAMVA (Lost Revs-Baseline)	Carrying Charges	Total Claim
Residential	$ 67,300	$ 55,518	$ 11,782	$ 151	$ 11,933
General Service less than 50 kW	$ 43,794	$ 35,187	$ 8,607	$ 111	$ 8,718
General Service 50 to 4,999 kW	$ 180,799	$ 41,468	$ 139,332	$ 1,789	$ 141,121
Total	**$ 291,893**	**$ 132,172**	**$ 159,721**	**$ 2,051**	**$ 161,772**

LRAM Claim by Customer Class

Customer Class	LRAM Claim	Biling Unit	2017 Forecast Billing Units	2017 Proposed LRAM Rate Rider
Residential	$ 73,513	kWh	300,579,328	$ 0.0002
General Service less than 50 kW	$ 19,171	kWh	102,906,032	$ 0.0002
General Service 50 to 4,999 kW	$ 25,611	kW	1,259,313	$ 0.0203
Total	**$ 118,295**			

IR: 3.0 –VECC -23

Reference: **E3/T2/S2, page 4**
Load Forecast Model, CDM Results Tab
Exhibit 4, Attachment 4-J, page 7

a) Please provide any reports available from the IESO/OPA regarding the persistence of savings from 2011-2014 CDM programs through to 2017 (i.e., similar to the projections provided in the 2010 CDM Report for 2006 to 2010 programs).
b) Please reconcile the 2011-2014 CDM results as show in the CDM Results Tab with those set out in Attachment 4-J, Tables #1 and #5. In particular, it appears that the values as set out in the CDM Results Tab have not been appropriately adjusted to account for "Adjustments to Previous Years' Verified Results" as shown in Attachment 4-J, Table 1.

Response:

a) BPI has provided reports available from the IESO/OPA regarding the persistence of savings from 2011-2014 CDM programs through to 2017 (i.e., similar to the projections provided in the 2010 CDM Report for 2006 to 2010 programs) as Attachments 3-VECC-23-A and 3-VECC-23-B.
b) BPI agrees that the values as set out in the CDM Results Tab have not been appropriately adjusted to account for "Adjustments to Previous Years' Verified Results" as shown in Attachment 4-J, Table 1. The following table shows the "Adjustments to Previous Years' Verified Results" in the applicable years.

CDM Program year	**2011**	**2012**	**2013**	**2014**
Amounts as reported in Application	**4,515,774**	**5,363,496**	**5,079,363**	**35,997,464**
Timing - Adjustments related to previous years				
2011	(229,429)	230,189		(760)
2012		260,528	(83,141)	(177,387)
2013			1,997,757	(1,997,757)
Adjusted Totals	**4,286,345**	**5,854,213**	**6,993,979**	**33,821,560**

IR: 3.0 –VECC -24

Reference: E3/T2/S2, page 9

a) Please provide the actual customer/connection count for each class as of June 30, 2016.

Response:

The table below shows BPI's customer count as at June 30, 2016. Please note BPI and the City of Brantford have determined that the number of connections has been incorrectly reported in the past and beginning in 2017 the correct number of connections, 6351, will be used for tracking and billing purposes. BPI used the updated connection number in its load forecast and rate design and has based its cost allocation on the updated number of connections.

Customer Class	Count at June 30 2016
Residential	35,981
General Service < 50 kW	2,795
General Service > 50 kW	454
Embedded Distributor	1
Unmetered Scattered Loads	427
Streetlight Connections	10,229
Sentinel Light Connections	577

IR: 3.0 –VECC -25

Reference: E3/T2/S2, page 9

a) Please explain the historical decrease in Streetlight use per connection. Is it due to reductions in energy use per device or due to a decrease in the number of devices per connection?

Response:

The historical decrease in Streetlight use per connection is due to reductions in energy use per device resulting from the installation of more efficient streetlights when new or replacement lights are installed as well as the shift to LED lights. Please note that while there has been no decrease in the number of devices, BPI and the City of Brantford have determined that the number of connections has been incorrectly reported in the past and beginning in 2017 the correct number of connections will be used for tracking and billing purposes. BPI used the updated connection number of 6351 in its load forecast and rate design and has based its cost allocation on the updated number of connections.

IR: 3.0 –VECC -26

Reference: E3/T2/S2, page 12

a) Please provide a copy of Brantford's 2015-2020 CDM Plan as submitted to the IESO.

Response:

a) A copy of Brantford's 2015-2020 CDM Plan as submitted to the IESO is included as Attachment 3-VECC-26.

IR: 3.0 –VECC -27

Reference: E3/T2/S2, page 14

a) Given that the full year net level savings are used for LRAM purposes and the load forecast model uses 2015 data why are savings from 2015 CDM programs included in the LRAMVA baseline?

Response:

BPI agrees the 2015 CDM programs should be excluded in the LRAMVA baseline. The following table reflects the adjustment.

Year	Residential	GS<50	GS>50	Sentinel	Streetlight	USL	Total
2017 LRAMVA kWh	840,580	805,502	13,889,828				15,535,910
2017 LRAMVA kW			35,765				35,765

IR: 3.0 –VECC -28

Reference: E3/T2/S2, page 17

a) Please provide a schedule that sets out the actual energy use and billed kW for the first seven months of 2014, 2015 and 2016 for: i) the Embedded Distributor and ii) the Wholesale Market Participant.

Response:

The following schedule sets out the actual energy use (kWh) and billed (kW) for the first seven months of 2014, 2015 and 2016 for both the Embedded Distributor and Wholesale Market Participant rate classes.

Month	Embedded Distributor						Wholesale Market Participant					
	2014		2015		2016		2014		2015		2016	
	Energy Used (kWhs)	Billed (kWs)	Energy Used (kWhs)	Billed (kWs)	Energy Used (kWhs)	Billed (kWs)	Energy Used (kWhs)	Billed (kWs)	Energy Used (kWhs)	Billed (kWs)	Energy Used (kWhs)	Billed (kWs)
January	7,540,983	14,443	7,118,842	13,631	5,918,030	11,140	539,050	899	509,277	854	506,989	841
February	6,680,179	13,719	6,631,977	13,182	5,487,795	11,341	490,253	921	459,636	833	470,186	848
March	7,019,355	14,947	6,455,514	12,535	5,376,000	11,139	548,268	949	532,234	871	519,551	908
April	5,865,475	13,508	5,411,872	10,944	4,937,817	10,670	548,443	1,044	540,243	1,036	516,200	1,016
May	5,650,928	13,613	5,249,954	10,769	4,919,923	10,419	599,690	1,181	606,937	1,165	578,760	1,134
June	5,933,375	14,271	5,260,160	10,983	5,103,880	11,467	638,127	1,220	598,590	1,173	609,121	1,155
July	6,169,396	14,796	5,960,525	12,311	5,887,617	12,628	673,542	1,201	658,590	1,160	635,290	1,181

IR: 3.0 –VECC -29

Reference: E3/T3/T1, page 5

a) Has Brantford also reduced its forecast OM&A for 2016 and 2017 to account for the expected decrease in field connection activity (per lines 15-18)? If so, please indicate where in Exhibit 4 the reduction is reflected.

Response:

No, BPI has not reduced its OM&A forecast for the expected decrease in field collection activities. However, BPI has experienced lower-than-anticipated take-up on OESP in its service area, and the June 2016 YTD numbers indicate the decrease in field collection charges is not materializing as expected.

Exhibit 4: Operating Expenses

IR: 4-Staff-40

Ref: Exhibit 4, Tab 2, Schedule 1

Brantford Power has described its budget process in this exhibit.

a) Does the budget process specifically consider bill impacts?
b) Was Brantford Power's Board of Directors given information regarding the proposed bill impacts in this application?
c) If so, were the bill impacts specifically approved by the Board of Directors?

Response:

a) Although the budget process does not include the determination of bill impacts at a specific customer class or consumption level, the process does consider the overall impact on the level of distribution revenues which is used as a proxy for bill impact considerations. As outlined in Exhibit 1, Tab 1, Sch 3 Page 4 of 5 Table 1-1D Key Budget Considerations, the budget process considers the five stated factors in assessing the reasonability of a budget proposal which includes Stakeholder Input which "requires the business to consider and assess the impacts of any significant decision on… customers".

b) Yes, the Board of Directors was provided an illustration of the rate and bill impacts based on the current information available at the time of the April 28, 2016 Board Meeting. They were provided a view of the rate impact on total bill and distribution portion of the bill for each customer class at the typical consumption levels. (Note: There were very minor changes to the finalized rate impacts following the Board meeting to reflect minor calculation corrections identified during final internal quality assurance reviews completed prior to filing the Cost of Service Distribution Rate Application. These changes resulted in no material changes to the information presented to the Board members).

c) No, the information was provided as an information item and no approvals were requested. Please also refer to the response to 1-SEC-8

IR: 4-Staff-41

Ref: Exhibit 4, Tab 2, Schedule 1, page 3

Brantford Power states that its senior leadership team considers feedback received and direction from the Board of Directors prior to finalizing the budget. Please provide examples of the feedback received and resulting changes to the 2017 budget.

Response:

BPI's Senior Leadership Team typically presents a budget update at the October Board of Directors meeting which outlines some of the key budgetary issues as well as the tentative plans it has developed to address them. These typically include:

- Key industry developments and any implications to the budget;
- Overview of key budget risks and uncertainties;
- Understanding of the staffing levels planned and other major departmental projects;
- Magnitude of expected distribution revenue adjustments and likely impacts on customers;
- The expected impact of the Senior Leadership Team's budget plan on the budget year and forecasted financial position of the business in relation to the availability of capital and the timing of planned investments for customer, strategic or other business initiatives.

As the purpose of this initial meeting with the Board of Directors is to provide an update on the budget process, the feedback received is obtained through questioning by the Directors and no formal direction or resolution is typically provided at this time. Based on this interaction with the Directors, the Senior Leadership Team will be able to determine whether its current approach is in keeping with the Board of Directors' expectations or whether there are specific areas that need to be revisited before a final budget proposal is submitted for approval.

During the October 2015 meeting, the Board of Directors was generally satisfied with the responses to their inquiries and the general direction of the Senior Leadership Team's budget plan and they did not provide any specific feedback requiring a change to the tentative budget plan.

During the December 2015 Board of Directors meeting where the final budget was presented and approved, the Board of Directors provided feedback that they acknowledged the requirement for accepting a lower rate of return in 2016 (Bridge Year) as the planned spending influenced by major projects such as the transition to new facilities and the acquisition and implementation of a financial information system reflected Brantford's transition from the planning phase to the execution phase on these major initiatives. Such transition requires one time and ongoing OM&A and capital funding that were not contemplated in the funding envelope resulting from the 2013 cost of service decision.

The Board of Directors indicated it was prepared to approve the 2016 and 2017 budgets as submitted so that the business can proceed on a timely basis with the required business renewal projects. The Senior Leadership Team was requested to ensure that the 2017 Cost of Service Distribution Rate application reflect a revenue requirement request that is sufficient to recover Brantford Power Inc.'s prudently incurred cost of service necessary to achieve a reasonable return on equity at the level established by the Ontario Energy Board of Directors.

In keeping with this Direction, the Senior Leadership Team ensured its 2017 Cost of Service Revenue Requirement reflected more current information than was available in the budgets submitted to the Board of Directors. Among these changes were the following:

- Update to the Systems Integration Costs to reflect a change in the hosting arrangements contemplated and the pacing of the underlying costs over the next IRM period;
- Updated timing of certain capital projects to reflect revised third party information regarding the timing and scope of such projects;
- Updated for the amortization over 5 years of System Integration Project OM&A costs and Regulatory One-Time Costs;
- Updates for building rate base adjustment, etc.

IR: 4-Staff-42

Ref: Exhibit 4, Tab 2, Schedule 1, page 3

Table 4.2-B opening balance for the last rebasing year of $8,854,025 is the OEB approved OM&A expense from Brantford Power's last cost of service. Brantford Power has included a "final settlement reduction from 2013 COS" as a cost driver in this table. Please explain why the final settlement adjustment is not included in the opening balance?

Response:

BPI's settlement in its 2013 COS was completed in February of 2014. BPI had updated its evidence during interrogatories to provide 2013 November Year to Date plus forecast OM&A, which was largely in keeping with the 2013 final numbers. The final settlement resulted in a further reduction to OM&A of $108,275. As the costs for 2013 had already been incurred, this reduction created a variance between 2013 Board Approved and 2013 Actuals.

IR: 4-Staff-43

Ref: Exhibit 4, Tab 2, Schedule 1, page 7

Brantford Power's application contains no actual data for 2016. Procurement and implementation of the new FIS have begun with a forecast in-service date of December 31, 2016.

a) Please provide a status update for this project.
b) Is the expected in-service date still December 31, 2016?
c) Please provide an update to the forecast costs.
d) Please provide a copy of the RFP.
e) Please provide a decision matrix employed in the decision process (you may redact applicants' names), indicating the preferred vendor.

Response:

a) BPI response: BPI completed the planning phase of the project with the short listed vendor ('preferred vendor') in May 2016 and completed the contract negotiations by mid June 2016. On June 17, 2016, BPI signed a final Master Services Agreement (MSA) which encompassed procurement of software licenses, hosting facilities, hosting services and implementation services for the FIS solution. BPI has commenced the design phase of the project on June 20, 2016 and as of August 18, 2016, BPI has completed a number of the design phase activities working with the preferred vendor (and their methodology and approach), including:

- Application walkthrough sessions completed by July 8, 2016
- Application design sessions completed July 28, 2016
- Data conversion design sessions are in progress
- Integration design sessions are completed and integration specifications document is being developed
- To-be process flow reviews are under way and expected to complete by early September 2016. Design books that document the outcome of design sessions are being drafted by the preferred vendor and plans for BPI to review the design books in early September 2016.
- Environment setup and application installations are complete.
- Overall, all design phase activities are planned for completion by late September 2016 and BPI and the preferred vendor do not see any issues or significant risks that could affect the completion of these activities in the timeline planned.

b) Yes. As per the status above, design phase is well underway and on track for completion as planned. Other activities leading up to the go-live (in-service date) are as follows:

- Configuration phase activities (configuring the application based on the design session inputs) will commence in parallel and is expected to complete by September end.
- The preferred vendor will then complete their own test/quality assurance of the configured environment before releasing to BPI for testing in early to mid-October 2016. BPI user acceptance testing and training is expected to occur from mid-October to end of November 2016.
- Deployment and rollout activities of the application are expected to occur in December 2016 leading to a fully functional live environment on December 31, 2016.

c) BPI response: Below is an update of the forecast costs for the FIS project. These costs are based on the final signed contract with the FIS preferred vendor plus additional BPI internal resource cost estimates refined based on the inputs received during the planning phase and through contract negotiations.

Revised project cost - Capital vs Operating split by year

Cost type	FIS revised cost	2016 Capital	2016 O&M	2017 O&M	Notes
Onetime costs:					
Software licensing	$412,648	$412,648			1
Implementation services (external)	$689,293	$344,647	$344,647		2
Internal resource costs	$460,962	$152,117	$235,292	$73,553	2
Other expenses	$44,000		$44,000		1
Total onetime costs	**$1,606,902**	**$909,412**	**$623,938**	**$73,553**	
Recurring costs (annual):					
Support and maintenance	$80,767		$80,767		1,4
Hosting charges	$58,749		$58,749		1,4
Total recurring costs	**$139,516**	**$0**	**$139,516**	**$0**	
Total costs	**$1,746,419**	**$909,412**	**$763,455**	**$73,553**	
Contingency (25% of total costs)	$436,605	$227,353	$190,864	$18,388	
Total costs (including contingency)	**$2,183,023**	**$1,136,764**	**$954,318**	**$91,941**	
		52%			
FIS costs included in 2016 numbers for COS Rate application	**$1,610,124**	**$845,907**	**$764,217**	**$0**	
Increase / (decrease)	**$572,899**	**$290,857**	**$190,101**	**$91,941**	
		51%			
Original budget costs		*$48,500*			

Notes:
1. All licensing costs are capitalized (as intangible assets). All support, hosting and expenses are expensed to Operating & Maintenance (O&M)
2. Implementation services costs (external) are capitalized at 50%, while internal resource costs are capitalized at 33%
3. 2017 costs split out relate to end-user training on budgets and final validation of budgets for go-live in 2017 as part of the 2018 budget cycle.
4. Recurring costs for support and hosting continue in 2017 as regular operating expense; not shown here to keep tie-in to the project cost
5. The proportion of capital to total costs (50-55%) is consistent - from the COS rate application numbers to the revised FIS cost

d) 4-SEC-18-c.1 FIS-RFP.zip – contains the RFP issued and appendices that accompanied the RFP

4-SEC-18-c.2 FIS-BAFO.zip – contains the Best-And-Final-Offer (BAFO) document, which was issued to two short listed proponents based on an evaluation of the RFP responses from the proponents. The BAFO was designed to get further information and a final offer for BPI consideration and final selection.

e) Below is a summary of the procurement process and stages through which BPI evaluated the RFP respondents, progressively shortlisted the respondents and leading to the final selection of the preferred vendor:

- BPI issued an RFP for the FIS solution to the market in April 2015. See copy of RFP attached in response to (d) above
- Three vendors responded to the RFP. BPI eliminated one vendor due to the lack of their experience in the electricity distribution market and specifically in the Ontario markets. This was a key requirement and the RFP had specifically outlined that vendors not compliant with this requirement would not make it to the subsequent stages in the procurement.
- BPI requested the remaining 2 vendors ('the preferred vendor' and 'the competing vendor') to provide demonstrations and supply reference checks. BPI reviewed the demonstrations and performed reference checks to further evaluate the two vendors. BPI used a score based evaluation framework (that was defined prior to the issue of the RFP). Both vendors were comparable in their scores (including the pricing score)
- BPI then issued a BAFO to obtain further competitive quotes from both vendors and obtain further details on aspects of the proposal that were unclear. One of the additional asks was for both vendors to also provide an estimate of the BPI internal resource requirements to execute the implementation project for the FIS.
- Both vendors responded to the BAFO and submitted their revised quote and responses to questions in the BAFO, including an estimate of the BPI internal resources
- On further evaluation and scoring of the BAFO responses, BPI selected the preferred vendor for contract negotiations due to the following reasons:
  - Internal (BPI) resourcing expectations for the project were significantly higher for the competing vendor in comparison to the preferred vendor.
  - The preferred vendor's solution was far more comprehensive and specific to an LDC; brings together Microsoft Dynamics GP (for the core ERP functions), Prophix (for budgeting models and Corporate Performance Management or CPM), WennSoft Job costing solution and Quadra (Engineering standards and estimation) . The competing vendor positions only the JD Edwards solution (which is a core ERP solution only) without sufficient clarity or detail on the other aspects of the requirements.
  - The preferred vendor has experience implementing the solution at 20 utility/electric and related companies in Ontario with an additional 37 in the

USA -Water, Gas and Electric. The competing vendor did not respond fully to that question/ask. Further, BPI talked to a number of the preferred vendor references and received positive feedback on the solution and the vendor. In contrast, the competing vendor references did not support sufficient experience in the Ontario LDC market.

- BPI then engaged in a planning phase (scope determination phase) with the preferred vendor to allow the vendor to fully appreciate the scope and provide a fixed price contract for the hosting, software, implementation and support services. BPI also explored alternative models of hosting with the preferred vendor and comparative pricing under each model before determining the model and solution that best fit BPI needs. The outcome of the planning phase and the contract negotiations further confirmed that the preferred vendor was best suited to meet BPI's needs.

IR: 4-Staff-44

Ref: Exhibit 4, Tab 2, Schedule 1, page 10

Brantford Power has amortized the implementation costs of its system improvements over 5 years, similar to the process employed in a custom IR application.

a) Please explain why Brantford Power believes that this treatment is appropriate in a one year cost of service application.

Response:

The primary motivation for proposing this approach was to ensure that the 2017 OM&A revenue requirement impact for this major multi-year Information System Integration and Renewal Program did not reflect a higher OM&A component than the average level of annual costs during the next five years. The level of 2017 costs would be higher than the average annual costs simply because of the timing and mix of the particular projects scheduled for roll out in 2017.

As the annual program OM&A cost represents a blend of transitional and on-going costs, the establishment of the 2017 OM&A revenue requirement based solely on the total expected level of cost for that single period would establish a level of funding that exceeds what would be required during the subsequent IRM years.

Given the expected lumpy and varied OM&A levels required to complete this multi-year Information System Integration and Renewal Program, BPI believes it is a fairer approach to establish the base OM&A funding level at the average level for the period for the following reasons:

- It recognizes that this is a multi-year program with overall objective to renew BPI's Information System infrastructure and as a result, it does not have the same spending characteristics of regular ongoing OM&A expenses i.e. the base set in a given year is not necessarily the requirement in subsequent years as is often the case with regular OM&A spending;
- As the multi-year Information System Integration and Renewal Program involves a number of specific projects, during each year of the program, the required OM&A costs will reflect the following cost components particular to the menu and stage of completion for the particular projects planned for that year:
    - OM&A costs related to particular legacy systems that will end once equivalent replacement systems are in place;
    - the go-forward level of OM&A once the systems are in service;

- One time OM&A costs related to the implementation of new systems and decommissioning of old systems;
- Overlapping OM&A costs as both systems are operational during implementation and testing;
- Annualization in subsequent years of the above noted cost changes depending on when the new systems are put into service and old systems are removed;
- Annual changes in the portfolio and stage of projects will result in changing costing characteristics as the business completes a project and begins to ramp up with related new one-time and on-going transitional costs for the next project as those for the previous projects are no longer required. Although all projects are components of the Information System Integration and Renewal Program, each project will have its own scope and cost elements that can materially differ and impact the overall OM&A costs for any fiscal year depending on the roster for that particular year.

With the amount of variables outlined above, the net annual OM&A requirements for the program will differ from year to year due to the specific circumstances related to the difficulty, timing and scope of particular projects scheduled. The proposed approach will smooth out those impacts over the term of this Cost of Service application for this specific cost envelope.

- The OEB has already accepted the amortization approach on specific cost envelopes in the past by providing for the smoothing of OM&A costs related to a cost of service application over a number of years. Although this approach is related to a different specific cost envelope, Brantford submits the nature of its Information System Integration and Renewal Program would also benefit customers if a similar approach was accepted in this limited context.

IR: 4-Staff-45

Ref: Exhibit 4, Tab 2, Schedule 1, page 10, Table 4.2-C

Brantford Power's new FIS is proposed to be in service December 31, 2016. Please explain why the annual support fees for the current FIS continue to be paid to the City of Brantford after the new FIS is implemented.

Response:

BPI is not planning to migrate the detailed historical transaction data from the existing City FIS system to the new FIS system. In order to meet the regulatory and other requirements on retention of data, BPI has requested the City to allow BPI to maintain access to the historical information in the existing City FIS. Accordingly, the costs for FIS support have been retained at the same level year on year.

IR: 4-Staff-46

Ref: Exhibit 4, Tab 2, Schedule 1, page 11

Brantford Power has deferred its new CIS project until 2017, after completion of the FIS.

a) Please provide a status update for the CIS project, given any known delays in the FIS implementation.
b) How do any delays in implementing FIS or CIS affect the implementation of proposed OMS and TOU?

Response:

a) BPI response:

Status update for the CIS procurement project: BPI has prepared an initial draft of the RFP for the new CIS system. The RFP was on hold until BPI had completed the procurement of the new FIS system. With the completion of the FIS system procurement in June 2016, BPI has revived the efforts to review and finalize the RFP for the new CIS. Currently, BPI is performing this review and expects to issue the RFP to the market by early to mid October 2016.

FIS status: As explained in para (a) of the response to 4-Staff-43 question, there are no known delays at this point on the FIS implementation. And BPI expects to proceed as planned on the CIS procurement.

b) BPI response: Currently there are no foreseen delays in the FIS or CIS procurement that will impact the implementation of the proposed OMS and TOU.

IR: 4-Staff-47

Ref: Exhibit 4, Tab 2, Schedule 1, page 13

The OMS and TOU systems have been budgeted based on a vendor quote.

a) Please describe the specific procurement processes that would be undertaken for these projects.
b) Please provide an update on the status and costs for these projects.

Response:

a) BPI response: BPI, in accordance with the procurement policy, plans to issue a formal RFP and obtain responses, similar to the process and steps taken in the procurement of the new FIS. At a minimum the following steps will be taken for the procurement:

- Issue RFP to market
- Obtain responses to the RFP from proponents and evaluate the responses using a scoring framework similar to the one used for the FIS selection
- Demonstrations from shortlisted vendors
- Reference call checks on all shortlisted vendors
- Contract negotiations and contract finalization.

b) BPI response: Currently the costs incurred on these projects so far are minimal. BPI is focused on the current FIS implementation and the CIS procurement. BPI expects the implementation timelines for the OMS and TOU projects to be relatively short. On completing the selection of the new CIS solution in late 2016, BPI will further evaluate integration of the prospective OMS and prospective TOU data with new

IR: 4-Staff-48

Ref: Exhibit 4, Tab 2, Schedule 1, page 13

Brantford Power is forecasting a decrease in services provided to affiliates in 2017 due to the plan to sell BGI to the City of Brantford in 2016.

a) Please provide the proportion of executive services provided to each affiliate in each of 2014, 2015 and 2016.
b) Please provide a status update on the proposed sale of BGI.

Response:

a) The table below outlines the proportion of services each year, calculated as the proportion of CEO and CFO salary allocated to affiliates compared to the total.

Year	Proportion Executive Services Allocated to Affiliates *
2014	11%
2015	37%
2016	24%
	* excluded Executive Assistant

b) The City of Brantford (COB), Brantford Generation Inc. (BGI) and Infrastructure Ontario (IO) have reached an agreement in principle to have the COB acquire all assets from BGI. For greater clarity given the wording of the question could imply the sale of the entity, the COB is acquiring all tangible and intangible assets from BGI. The COB is not acquiring BGI as a legal entity. The transaction closed on August 18, 2016.

As at May 2, 2016, all BGI operational responsibilities and custody of the assets have been transferred to the COB pending the transaction close. Consequently, the Executive Services no longer relate to facility operations. The remaining BPI responsibilities will be limited to a custodian role of the legal entity including being responsible for the remaining corporate administration functions until such time as the legal entity is dissolved anticipated later in 2016 or early 2017.

IR: 4-Staff-49

Ref: Exhibit 4, Attachment 4-K, page 19

One of the next steps identified in the compensation review process is identifying the frequency of future reviews. What are Brantford Power's plans regarding future compensation reviews?

Response:

BPI does not anticipate it will conduct another fulsome compensation review within the next 5 year period. BPI intends to use this period to implement the planned outcomes of the compensation review, and to monitor progress and assess the effectiveness of the measures. If developments occur which impact BPI's ability to attract and retain talent, BPI will undertake reviews as necessary.

IR: 4-Staff-50

Ref: Exhibit 4, Tab 4, Schedule 2

Brantford Power has provided two sets of tables in its variance analysis for FTEs. Please explain the difference between these sets of tables.

Response:

The additional FTE variance analysis tables in Exhibit 4 appear as the result of a formatting error in the document. Please refer to the headings in each variance analysis explanation and to table 4.4-D for a confirmation of the correct variances.

IR: 4-Staff-51

Ref: Exhibit 4, Tab 4, Schedule 2

Brantford Power's FTEs have increased by 14% from 58 to 66 from 2013 OEB-approved. OEB staff notes that some of these positions are temporary.

a) Please provide the number of permanent and temporary positions contained in the 2017 test year.
b) Please provide the end date of the temporary positions included in the 2017 test year.

Response:

a) The 2017 test year includes 65 permanent and 6 temporary positions. Note these are counted on the basis of headcount, not FTE.

b) The table below shows the end dates for the positions included in the 2017 year. BPI notes that some of these positions are included in the system integration project OM&A costs which are proposed to be amortized over 5 years.

Dept	Title	Start Date	End Date
Customer Service	Supervisor	1-Apr-17	31-Mar-19
Customer Service	summer student	1-Jun-17	1-Sep-17
Customer Service	Customer Service/Billing Representative	1-Apr-17	31-Mar-19
Customer Service	Customer Service/Billing Representative	1-Apr-17	31-Mar-19
Finance	Acting Manager	current	31-Dec-17
Customer Service	Customer Service/Billing Representative	1-Jun-17	31-Dec-17

IR: 4-Staff-52

Ref: Exhibit 4, Tab 4, Schedule 2, page 2

Brantford Power introduced its STI program to senior leadership in 2014.

a) For each of 2014 and 2015, please provide the total possible maximum payout and actual total amount paid (NB – total, not per person)
b) Please provide the KPIs and KPI targets and actual performance for each of these years.
c) Please describe any plans that Brantford Power has to roll out the program to other levels of staff.

Response:

a) The total STIP Incentive Paid in each year, as well as the maximum possible payout for the executive group is shown in the table below:

	Total Paid	Maximum Payout
2014	$ 88,802.00	$ 103,918.74
2015	$ 79,178.00	$ 106,741.86

BPI notes this is the amount for the full executive group (made up of three VPs and the CEO). The maximum payout averages 18% of salary. The program was developed based on the work done with the Hay Group, which considered similar programs in comparable utilities, and the program was designed towards the median (50th percentile) of the industry practice. The amount paid in any year is related directly to BPI's performance on its corporate scorecard.

b) Refer to attachments to 1-SEC-9. Additionally, Attachment 4-Staff-52 is BPI's 2014 Corporate KPI document.

c) BPI plans to roll out a similar program this year to the non-union exempt staff. The plan is to implement for the 2017 performance year BPI plans to begin this rollout in Q4 2016. The program will also be related to the corporate scorecard KPIs in the same methodology as the previous 3 years.

IR: 4-Staff-53

Ref: Exhibit 4, Tab 5, Schedule 1, page 2

Brantford Power plans to negotiate a new shared services agreement to be effective January 1, 2017.

a) Please provide a status update for these negotiations.
b) If complete, please provide a copy of the new agreement.
c) If complete, please outline any impacts to Brantford Power's OM&A costs arising from the new agreement. Please include these impacts in the revisions requested in the response to 1-Staff-1, above.

Response:

a) BPI has some preliminary discussions with the City of Brantford to initiate discussions regarding the renewed SLA Agreement. BPI will assume Accounts Payable, Banking, Financial Information System (FIS), and Payroll responsibilities with the new FIS, which will be in service by December 31st, 2016. It is expected that the terms for the provision of other services will continue in keeping with the current agreement. BPI has not completed discussions nor has BPI drafted or signed a revised agreement. BPI has discussed the concept of renewing the existing agreement on a month to month basis until BPI can assess the organizational impact of FIS and whether changes in the remaining City of Brantford services are warranted.

b) As indicated above, the negotiations are not complete.

c) The negotiations are not complete.

IR: 4-Staff-54

Ref: Exhibit 4, Tab 7, Schedule 2

Brantford Power has included $13,560 in Incremental Costs related to its cost of service application. Please describe these costs.

Response:

The incremental costs include primarily incremental overtime cost, as well as other costs such as printing and courier costs.

IR: 4-Staff-55

Ref: Exhibit 4, Tab 4, Schedule 4, Page 2

Brantford Power provided the actuarial expense from 2013 to 2017. Please complete the 2017 Chapter 2 Appendix 2-KA.

Response:

BPI has provided the completed Appendix 2-KA below:

Appendix 2-KA
OPEBs (Other Post-Employment Benefits) Costs

A Please indicate if OPEBs were recovered on a cash or accrual accounting basis for each year since the distributor started to recover OPEBs

Notes:
(Please add any information to explain the accounting basis used for OPEBs cost recovery in rate setting. If basis is other than Cash or Accrual, an explanation is

In its 2013 Application, BPI moved to the cash basis for Post-Retirement Benefits expense, because actuarial costs were unavailable following BPI's 2012 restructuring whereby it ceased to become a virtual utility.

B Please complete the following table:

	Cash Basis - all OM&A					
OPEBS	**2013**	**2014**	**2015**	**2016**	**2017**	**Total**
Amounts included in	cash	cash	cash	cash	accrual - proposed	
OM&A	$ 108,000.00	$ 108,000.00	$ 108,000.00	$ 108,000.00	$ 120,272.17	$ 552,272.17
Capital	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ 108,000.00	$ -	$ -	$ -	$ -	$ 108,000.00
Paid benefit amounts	-$ 108,682.00	-$ 70,000.00	-$ 52,222.00	-$ 55,147.00	-$ 55,698.17	-$ 341,749.17
included in rates relative to amounts actually paid.	-$ 682.00	$ 38,000.00	$ 55,778.00	$ 52,853.00	$ 64,574.00	$ 210,523.00

C Please describe what the distributor has done with the recoveries in excess of cash payments:

IR: 4-Staff-56

Ref: Exhibit 4, Attachment 4-A

Brantford Power provided the 2015 Actuarial Report which determined the 2015 net benefit cost. Did Brantford Power obtain an actuarial report for the transition to IFRS? If yes, please provide the report and indicate the change in OPEBs due to the transition to IFRS.

Response:

BPI obtained a summary Actuarial Report in CGAAP for 2015, which is included as Attachment 4-Staff-56. The change in OPEBS cost due to the transition to MIFRS is and increase of $37,717 in 2015, related to the recognition of actuarial gains in OCI for MIFRS as opposed to in Net Benefit Cost under CGAAP.

	2015 CGAAP		2015 MIFRS
Net Benefit Cost		**Defined Benefit Cost**	
Accrual for service	$71,129.00	Service Cost	$71,129.00
Interest on Accrued Benefits	$ 43,753.00	Net interest cost on net defined benefit liability (asset)	$ 43,753.00
Actuarial (gains) losses during the year	($31,717.00)		
Net Benefit Cost Incurred	**$83,165.00**	**Defined Benefit Cost**	**$114,882.00**
		Re-measurements of net defined benefit liability	
		Actuarial loss(gain) arising from changes in financial assumptions	$ (31,717.00)
		Total amount recognized in OCI	**$ (31,717.00)**

IR: 4-Staff-57

Ref: Exhibit 4, Tab 9, Schedule 1, Pages 9, 11-15

With regards to the depreciation schedules from 2013 to 2017:

a) Please explain why the useful lives on new additions for each account is different each year from 2013 to 2017 (E.g. Account 1830 is 18.31 years, 47.33 years, 43.19 years, 27.04 years, 26.67 years from 2013 to 2017).

b) Please explain how the useful lives in the depreciation schedules reconcile to that in Chapter 2 Appendix 2-BB (E.g. Account 1830 is 45 years).

c) There is a depreciation expense adjustment from the loss on retirement of assets of $100k in 2017.

   i. Please explain to what this loss pertains.

   ii. No other gains or losses on retirement of assets were included from 2013 to 2016. Please explain why this is the case and please explain Brantford Power's process for identifying gains and losses on retirement of assets.

Response:

a) This is due to the fact that there are different useful lives used within each USoA account. For example, in Account 1830- Poles, Towers and Fixtures, BPI has Wooden Poles with a useful life of 45 years, Concrete Poles with a useful life of 60 years and Major Inspection-Poles with a useful life of 3 years. Therefore BPI has taken the weighted average of the addition values and the useful lives for each component of 1830 for each year.

b) As mentioned above, BPI uses the weighted average method to calculate depreciation expense each year. For example in Chapter 2 Appendix 2-BB under Account 1830 is Wooden Poles with a useful life of 45 years and Concrete Poles with a useful life of 60 years. This reconciles with the useful lives that BPI has used in the depreciation schedules, however the useful lives shown in the depreciation schedules are the weighted average for account 1830 as a whole, whereas the useful lives shown in Chapter 2 Appendix 2-BB is the useful life for each component under each account, in this case, each component of 1830.

c) i) This loss pertains to the disposal of Poles (1830) and Transformers (1850). As per Chapter 2 Appendix 2-BA "Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately."
ii) Prior to 2017, loss on disposal is recorded into variance account 1575- IFRS-CGAAP Transition PP&E. From 2017 going forward, loss on disposal is grouped with amortization, therefore should be recorded into 5705- Amortization Expense.
BPI has two different process for identifying gains and losses on retirement of assets:

1. Outright sale/trade-in of an identifiable asset (ie fleet disposals):
   a) System is reviewed to determine if any residual value exists for the asset
   b) Asset is written off
   c) Any proceeds on disposal are net against the NBV to determine total gain/loss

2. Early disposal of pooled assets:
   a) Finance gets the GIS data for poles and transformers on a quarterly basis
   b) Compare the data to the previous quarter data to determine which assets are no longer in service
   c) Review installation dates from the GIS data to determine which items haven't been fully amortized
   d) Confirm with Engineering that the asset was removed and wasn't just a GIS clean up change
   e) Determine average cost of the asset based on the number of the particular type of asset that were installed in the same year that were still in service at the beginning of the year (ie wooden poles installed in 2006)
   f) Write off the estimated cost and accumulated amortization of the asset

IR: 4-Staff-58

Ref: Attachment 4-F PILS model

Ref: Attachment 4-G 2015 Draft tax return

Ref: Exhibit 2, Tab 1, Schedule 1, Pages 11 and 32

Ref: Exhibit 4, Tab 9, Schedule 1, Page 7

a) Historical Year UCC is $57.5M in the PILS model and $56.8M in Schedule 8 of the 2015 tax return, a difference of $743k. Please explain the difference between the UCCs and revise the PILS model as needed.

b) In Exhibit 2, the cost of the new "Property B" of $14.5M is included in rate base in 2016, where $4.5M is allocated to land and $10.25M is allocated to building (page 32).
   i. Please explain how this allocation was determined.
   ii. Please explain why the $10.25M is added to the PILS model UCC in Class 1 at 4% and not Class 1 Enhanced at 6%. Please revise the PILS model as needed.

c) In the PILS model, depreciation expense of $3.9M is added back to 2017 net income before taxes. In Exhibit 4, 2017 depreciation expense for rate setting purposes is $3.7M (after fully allocated depreciation). Please explain why $3.7M is not used in the PILS model. If the reason is due to an error, please revise the model accordingly.

Response:

a) Schedule 8 of the 2015 tax return. Refer to the table below for the updated Schedule 8-Historical Year.

Schedule 8 - Historical Year

Class	Class Description	UCC End of Year Historical per tax returns	Less: Non-Distribution Portion	UCC Regulated Historical Year
1	Distribution System - post 1987	27,601,502		27,601,502
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election			0
2	Distribution System - pre 1988			0
8	General Office/Stores Equip	566,830		566,830
10	Computer Hardware/ Vehicles	665,639		665,639
10.1	Certain Automobiles			0
12	Computer Software	56,463		56,463
13_1	Lease # 1	12,781		12,781
13_2	Lease #2	8,143		8,143
13_3	Lease # 3	10,845		10,845
13_4	Lease # 4			0
14	Franchise			0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs			0
42	Fibre Optic Cable			0
43.1	Certain Energy-Efficient Electrical Generating Equipment			0
43.2	Certain Clean Energy Generation Equipment			0
45	Computers & Systems Software acq'd post Mar 22/04			0
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)			0
47	Distribution System - post February 2005	27,799,956		27,799,956
50	Data Network Infrastructure Equipment - post Mar 2007	28,835		28,835
52	Computer Hardware and system software			0
95	CWIP			0
				0
				0
				0
				0
				0
				0
				0
				0
				0
				0
	SUB-TOTAL - UCC	**56,750,995**	**0**	**56,750,995**

b) This is no longer an issue with BPI's revised request to remove the building. Therefore BPI has not provided an answer to subsection b).

c) The PILS model adds back total deprecation (including fleet depreciation) as CCA is deducted instead for tax purposes on depreciable property. Fleet is included in Class 10 and therefore CCA is taken as a deduction on the tax return. Had BPI not added back the amortization on fleet, we would be taking a deduction on fleet twice (amortization & CCA). This is the same treatment as the 2015 tax return.

IR: 4-Staff-59

Ref: Exhibit 4, Tab 10, Schedule 2, Page 2

Property tax of $120,247 for 2017 does not appear to be included in the RRWF.

a) Please update the RRWF for property taxes.

Response:

a) BPI is withdrawing its request for building funding, and therefore does not have any property taxes associated with the building. However, there is $20,031 in property taxes associated with land that holds BPI's Distribution, Station, Building and Fixtures and BPI has made an adjustment in the RRWF in 1-Staff-1 accordingly. This amount was originally included in OM&A, but has since been re-mapped to account 6105- Taxes Other Than Income Taxes.

IR: 4-Staff-60

REF: Exhibit 4, Attachment 4-H, Burman Report

a) Please confirm that Brantford is requesting approval of lost revenues that totals $283,013.93 and is made up of the following components:
   - Lost revenues in 2013 from persisting 2006-2010 CDM savings in 2013 in the amount of $118,381.22; and,
   - Lost revenues in 2013 and 2014 (in account 1568) from savings from 2011, 2012, 2013 and 2014 CDM programs in 2013 and 2014 in the amount of $164,632.71.

b) Please provide all LRAM and LRAMVA calculations included within Brantford's application and the Burman report in live, unlocked MS Excel format.

c) Please provide all historic LRAM and LRAMVA requests for disposition and approvals that Brantford has received in the past.

d) Please provide additional rationale that supports Brantford's request to collect LRAM amounts related to the persisting savings of historic 2006-2010 CDM programs in 2013. In your response, please refer to Brantford's delayed 2012 cost of service application.

e) Related to Brantford's 2013 load forecast and CDM manual adjustment, please provide responses to the questions below:
   i) Please explicitly show the CDM amounts that were included as part of Brantford's 2013 load forecast.
   ii) Please expand on the discussion at Exhibit 4, Tab 11, Schedule 3, Page 2 of 3, where Brantford discusses its LRAMVA baseline. Please provide the CDM manual adjustment that was included and approved as part of Brantford's 2013 cost of service application.
   iii) Please reconcile the Load Forecast CDM Component rows of the Brantford Power LRAMVA Calculation table on page 13 of 18 of the Burman report with the CDM manual adjustment amounts included in Brantford's load forecast that were approved as part of Brantford's 2013 cost of service application.

f) Brantford is requesting to recover LRAMVA amounts in 2013 and 2014 related to the persisting CDM savings from 2011 and 2012 CDM programs. Please discuss the appropriateness of this request as Brantford had an updated load forecast, based on actual historic data (including CDM savings from 2011 and 2012), approved as part of its 2013 cost of service application.

g) Staff has identified a number of inconsistencies between Brantford's 2013 Final Results from the IESO and those savings included in its LRAMVA calculations. Specifically, the net energy savings in 2013 for the following 2013 CDM programs appear to not reconcile:
   - Conservation Instant Coupon Booklet
   - Home Assistance Program
   - HVAC
   - HVAC Incentives

- DR-3
- Energy Audit
- New Construction
- Business Retrofit
- High Performance New Construction

h) Please remove any demand savings related to demand response programs (Demand Response 3) in accordance with the OEB's Report (EB-2016-0182) issued on May 19, 2016.

Response:

a) BPI confirms it is requesting the amount of $118,381.22 for the persistence of 2006-2010 CDM savings into 2013. BPI's total request (in account 1568) is for $168,398.00 including carrying charges. This represents the impact of 2011 to 2014 programs in 2014. BPI is not claiming the amount of $3,307 calculated by Burman as the differences between the LRAMVA baseline included in the 2013 COS and the 2013 Actual CDM results. BPI's Settlement Agreement in EB-2012-0109 included the agreement that no amounts for 2013 would be booked to Account 1568. The derivation of the $168,398 included for disposition in account 1568 is below:

Burman LRAMVA total (excl. carrying charges)	$ 164,633.00
Less: Amount calculated for 2013 impact	$ (3,307.00)
Plus Carrying Charges	$ 2,072.00
Total Claim	$ 163,398.00

b) Please find as attachment 4-## a live excel version of BPI's calculations for LRAM and LRAMVA. BPI does not have a live excel version of the calculations in the Burman report. BPI has requested such a version, however Burman has declined to release the live excel version of the report in order to protect proprietary efficiencies built into the model. BPI understands that in previous cases involving Burman clients, this rationale for not providing the live calculations has been acceptable to Board Staff. In future LRAMVA claims, BPI will submit live calculations via the new LRAMVA work form, released in 2016 after BPI had filed this Application.

c) The table below summarizes BPI's past LRAM and LRAMVA Application and Decision outcomes:

	Application			Decision		
EB-2011-0147 (Rates Effective May 1, 2012)						
	Amount	**Revenues Lost in**	**Revenues lost due to Programs from**	**Amount**	**Revenues Lost in**	**Revenues lost due to Programs from**
LRAM	$ 643,351	2005 to 2010	2005 to 2011	$ 515,439	2005 to 2010	2005 to 2010
LRAMVA	$ -	N/A	N/A	$ -	N/A	N/A
EB-2012-0109 (Rates Effective March 1, 2014)						
	Amount	**Revenues Lost in**	**Revenues lost due to Programs from**	**Amount**	**Revenues Lost in**	**Revenues lost due to Programs from**
LRAM	$ 118,456	2005 to 2010	2011	$ 118,456	2011	2005 to 2010
LRAMVA	$ 103,767	2011 to 2012	2011 to 2012	$ -	N/A	N/A
EB-2014-0187 (Rates Effective January 1,2015)						
	Amount	**Revenues Lost in**	**Revenues lost due to Programs from**	**Amount**	**Revenues Lost in**	**Revenues lost due to Programs from**
LRAM	$ 116,048	2012	2006 to 2010	$ 116,048	2012	2006 to 2010
LRAMVA	$ 107,734	2011 to 2012	2011 to 2012	$ 107,734	2011 and 2012	2011 and 2012

d) The CDM Guidelines and the OEB's approval of BPI's previous and similar LRAM claims are the basis of BPI's understanding that it is eligible for the current LRAM claim. Namely the following items:

1) Distributors are eligible for LRAM claims related to pre-2011 CDM programs until new rates, based on a load forecast which has incorporated CDM results, are approved by the OEB;

2) The OEB confirmed in its Decision that BPI's 2008 load forecast did not incorporate the impacts of CDM programs.

3) BPI's distribution rates did not reflect an updated load forecast which included a CDM component until March 1, 2014 (the effective date of the OEB's Decision and Order in EB-2012-0109). The load forecast underpinning distribution rates charged throughout 2013 was the load forecast from BPI's 2008 Application.

Therefore BPI understands that it should be able to claim lost revenues related to pre-2011 programs in 2013.

BPI had been originally scheduled to file a new cost of service rate application with a test year of 2012. On April 28, 2011, BPI issued a letter to the OEB requesting permission to defer its Cost of Service beyond the 2012 rate year. On June 17, 2011, the OEB confirmed it would not require BPI to rebase its rates for the 2012 year.

If BPI had rebased its rates for the 2012 rate year, the load forecast would have reflected CDM reductions, preventing the creation of lost revenues in 2012 and 2013. However, as the distribution rates were not adjusted to incorporate the load forecast effects of CDM until 2014, BPI met the conditions for LRAM recovery in 2013. The intent of the current LRAMVA and the previous LRAM mechanism is to keep distributors revenue neutral for CDM activities between rebasing applications.

e) I) the CDM was reflected through the "manual adjustment" reduction of 2,538,855 kWh to the test year forecast for billed energy, representing projected 2013 CDM results of 5,077,710, adjusted for the half-year rule.

Ii) The manual adjustment is as follows (on the billed energy level, per rate class):

Residential	(673,430.62)	kWh
GS<50	(904,860.72)	kWh
GS>50	(960,563.40)	kWh
Total	(2,538,854.74)	kWh
GS>50 kW/kWhRatio	0.002545725	
GS>50 KW	(2,445.33)	kW

iii)

Comparison of expected 2011-2013 programs in 2013 to actual 2011-2013 programs in 2013

Difference is the impact of 2011 and 2012 actual programs and 2013 half year.

Total manual adjustment	
Half year of expected 2013 results	(2,538,854.74)
Expected full year results 2013 (per Settlement)	(5,077,709.48)
Add: Expected impact of 2012 results in 2013	(5,232,705.00)
Add: Expected impact of 2011 results in 2013	(4,498,762.00)
Expected 2011-2013 results in 2013	**(14,809,176.48)**

Allocation of Expected 2011-2013 results among rate classes:

	% allocated	kWh allocated	kWh-kW Adjustment	Variable Distribution Rt (2014 weighted avg)	Baseline Amount
Residential	27%	3,928,130.30	NA	$ 0.0141	$ 55,517.57
GS<50	36%	5,278,065.33	NA	$ 0.0067	$ 35,187.10
GS>50	38%	5,602,979.85	14,263.65	$ 2.9072	$ 41,467.52
					$ 132,172.20

f) The stated LRAMVA baseline from BPI's settlement proposal in EB-2012-0109 includes the assumed impact of 2011 and 2012 programs in 2013. For an apples-to-apples comparison in the calculation of LRAMVA using this baseline, BPI believes it is necessary to include the 2011 and 2012 savings.

g) BPI agrees there were a number of inconsistencies between Brantford's 2013 Final Results from the IESO and those savings included in its LRAMVA calculations. Please refer to interrogatory 3-VECC-23 and 3-VECC-22, in particular, Attachment 3-VECC-22 which is an updated report from Berman Energy Consultants which now agrees with the IESO results including any adjustment for prior years being reflected in the correct year. An updated LRAM claim has been provided under 3-VECC-22 b)

h) Please refer to 3-VECC-22 b) for an updated LRAM/LRAMVA claim. BPI confirms there are no DR-3 amounts included in the updated claim amounts.

IR: 4-Energy Probe-31

Ref: Exhibit 4, Tab 1, Schedule 1

Does Table 4.1-A include costs associated with property taxes and LEAP? If not, please provide the additional costs associated with each of these items for the 2013 through 2017 period, including Board approved 2013.

Response:

BPI confirms, Table 4.1-A includes costs associated with Property Taxes and LEAP.

IR: 4-Energy Probe-32

Ref: Exhibit 4, Tab 1, Schedule 1

Please provide the most recent year-to-actual OM&A expenses available for the 2016 bridge year in the same level of detail as shown in Table 4.1-A. Please also provide the figures for the corresponding period in 2015.

Response:

Refer to Table 4-EP-32 below.

Table 4-EP-32

Expenses	2016 June YTD	2015 June YTD
Distribution Expenses - Operation	721,809	516,556
Distribution Expenses - Maintenance	574,693	613,642
Billing and Collecting	1,471,603	1,200,323
Community Relations	2,187	7,741
Administrative and General Expenses	1,851,356	1,302,438
Total	**4,621,649**	**3,640,701**

IR: 4-Energy Probe-33

Ref: Exhibit 4, Tab 2, Schedule 1

With respect to each of the following items in Table 4.2-B:

a) Smart meter contra adjustment – Was any of the $536,035 shown as adjustments in 2013 and 2014 costs that were actually incurred in 2013 and 2014 or were these amounts that were incurred in 2012 and previous years? Please explain fully.

b) What was the actual OM&A expense incurred in 2013 related to smart meters and is this amount included in the 2013 Board approved and/or 2013 actuals?

c) Employee future benefits actuarial valuation and severance adjustments – Please break these costs into each of the items noted. Please also indicate which adjustments were one-time events.

d) Construction materials and supplies – line transformers – Please explain why this is an adjustment to OM&A when it appears these would be capital costs.

e) One-Time costs relating to Cost of Service filing – Is the $63,700 shown for 2016 included in Table 4.1-A for 2016? Is this amount also included in the regulatory costs that are proposed to be amortized over 5 years?

Response:

a) The 2013 Board Approved OM&A costs were settled in February 2014, using November 2013 YTD actuals to project the costs for the remainder of the year. The 2013 Actual OM&A costs included a credit of $174,035 representing smart meter operating costs that were reallocated from OM&A to Account 1555 (Smart Meter Capital & Recovery) as the disposition of smart meters did not occur until February 2014. The 2013 Board Approved trial balance was based on November YTD balances, which did not include these adjustments for smart meters, creating a variance from 2013 Board Approved Trial Balance to 2013 actual Trial Balance. Beginning in 2014, the OM&A costs relating to meters were kept in OM&A, therefore creating another variance from 2013 actuals to 2014 actuals. The remaining $362,000 represents amortization expense on smart meters that was offset by 5705 (amortization expense). These adjustments were not reflected in the Board Approved OM&A costs. The smart meter disposition took place in February 2014, as a result of the 2013 Cost of Service application, and therefore smart meter operating costs remained in OM&A during 2014 and future years. Beginning in 2014, amortization expense on smart meters was posted directly to account 5705, instead of a regulatory asset account.

b) See above.
c) Only the severance accrual adjustment is a one-time item.
d) Please see the breakout below :

	2013 BA to 2013 AC		2013 AC to 2014
Adjustment for severance accrual	$ 252,373.00		(337,141.00)
Retiree Benefits	$ -		(86,216.55)
Total	$ 252,373.00		(423,357.55)

e) This was an accounting error and should have been capital and not OM&A.

IR: 4-Energy Probe-34

Ref: Exhibit 4, Tab 2, Schedule 1

a) Where is the increase associated with the facility manager position shown for 2017, given that this cost was capitalized in 2016?

b) What is the increase in 2017 relative to 2016 associated with this position?

Response:

BPI is withdrawing the request for funding for its facility in the Bridge and Test Years. Please refer to the response to 2-Staff-7 for further information. As part of this change, BPI has removed the costs associated with facility manager position.

IR: 4-Energy Probe-35

Ref: Exhibit 4, Tab 2, Schedule 1

a) Please provide a reconciliation between the changes shown for 2016 and 2017 of $868,191 and -$486,476, respectively, for the system integration projects shown in Table 4.2-B and the figures shown in in Tables 4.2-C through 4.2-F.

b) Please explain what costs are included in the implementation costs associated with the FIS and CIS and explain why these costs are expensed and not capitalized.

c) What are the capital costs associated with the FIS and CIS projects and where are they reflected in the fixed asset continuity schedules for 2016 and 2017?

Response:

a) Please note that 2015 information is not provided in Tables 4.2-C through 4.2-F. The following reconciliation includes 2015 as it would appear had it been included in those tables. BPI has discovered there was an amount allocated to SIP projects of $43k that should not have been. This is identified in the reconciliation as the Cost Driver Table allocation error.

It is important to note that this error only affected the classification in the Cost Driver Table and that the budget and revenue requirement amounts are correctly stated in the application.

	2015	2016	Change 2015-2016	2017	Change 2016-2017
Table 4.2-C - FIS	15,336	778,428	763,092	289,642	(488,786)
Table 4.2-D - CIS	562,704	636,775	74,071	1,496,137	859,362
Table 4.2-E - Other SIP	-	31,029	31,029	306,905	275,876
	578,040	**1,446,232**	**868,192**	**2,092,684**	**646,452**
Normalization of 2017-2021 costs (Table 4.2-F)			-		(1,176,180)
Net Change			**868,192**		**(529,728)**
Net Change (as shown in Table 4.2-B)			**868,191**		**(486,476)**
Vaiance (Cost Driver Table Allocation Error)			**1**		**(43,252)**

b) Not all costs have been expensed. Some of the costs have been capitalized. BPI has estimated and capitalized the software license costs and any costs directly related to putting the software to use (such as implementation services fees and cost of internal resources time for design, build and testing activities). Expensed costs include annual hosting fees, annual enhancement or maintenance fees, and portion of the implementation services fees and cost of internal resource time for project management, training and other administrative activities).

c) Table 4.2-C (FIS – Implementation and OM&A Costs) and Table 4.2-D (CIS Implementation and OM&A costs) only show the portion of the costs that are expensed to OM&A. The capitalized costs are included in the assets - see Exhibit: 2 – Attachment A – DSP, Figure 54: General Plant Capital Projects forecast.

Below are the details on the costs included and whether they have been capitalized, expensed or partly capitalized.

Type of cost	Description / detail	Capital vs Expense treatment
Software license cost	Cost of the software licenses (including base module license costs which is fixed and per-user license costs) paid (or expected to be paid) to the software vendor. Per-user license costs are estimated based on the number of users and applying the rates for licensing (some software vendors license based on concurrent users and others based on named user license).	Capital (intangible asset)
Software annual enhancement fee (or maintenance)	Annual fees charged by the software vendor to allow access to software updates, releases and upgrades. The fee is typically a percentage of the above software license cost.	Expense
Implementation services costs (or professional fees)	Costs paid to external consultants for services rendered to implement the software. Typical activities performed by the external consultants include software installation, design, configuration of the procured software to suit BPI needs, building interfaces and reports required by BPI, quality assurance and testing and other project management and	Cost of implementation services towards design, build and test of the software are treated as capital. These were estimated at 50% of the overall implementation services costs based on the estimates provided by the

Type of cost	Description / detail	Capital vs Expense treatment
	administrative activities necessary to successfully implement the software solution.	FIS consultant. Cost of implementation services towards other activities (like project management, training etc.) are treated as expense. Remaining 50% of the implementation services costs treated as expense and included in OM&A.
Hosting charges	Annual charges paid for hosting the software at a third party hosting provider	Expensed entirely.
Internal resources costs	Cost of internal resources time to implement the software solutions. Similar activities as performed by the external consultant above but required to be performed by BPI employees.	Similar to the external professional fees, a portion of the internal costs are capitalized. BPI estimates 33% of the internal costs to be invested in design, build and testing activities and has hence capitalized these. Remaining 67% is expected to be project management, training, data clean-up and other administrative activities and expensed.

d) In 2016, $845,907 is the capital cost associated with FIS which is reflected under 1925- Computer Software in the continuity schedules. In 2017, $682,149 and $239,904 are the capital costs associated with the CIS and Operations and Customer Service OMS projects respectively. These additions are also included under 1925- Computer Software in the continuity schedules.

IR: 4-Energy Probe-36

Ref: Exhibit 4, Tab 2, Schedule 1, page 15

The evidence states that BPI is forecasting a decrease in service provided to the affiliates in the 2017 test year, resulting in an increase in OM&A because BPI will no longer be providing services to BGI, as a result of the plan to sell BGI's assets to the City of Brantford.

a) What is current status of this proposed sale?

b) Please confirm that the total cost of providing the services to BPI and its affiliates is not going up, but rather BPI will be allocated a larger portion of the costs in the test year.

c) Please explain why the total cost of providing the services to BPI and its affiliates is not decreasing, given that services will no longer be provided to BGI.

Response:

a) Please refer to the response to 4-Staff-48, part b.

b) The total cost of providing services to BPI and its affiliates will be going up in the normal course to reflect salary and wage adjustments, inflation and other costs changes as determined through the budget process in the ordinary course. Other than business process changes resulting from the introduction of a new Financial Information System and in-sourcing of certain FIS related functions from the City of Brantford and transitioning from the City of Brantford to a new payroll, there are no other anticipated changes in service level or scope of services.

c) The total costs are not decreasing for the following reasons:

- As BGI represented a very simple company with a limited number of transactions, BGI's share of the day to day support services to the group of companies was relatively small. The larger charges attributable to BGI in 2015/2016 was largely related to one time executive time spent on negotiating the financial restructuring for BGI.

- As part of the transition plan for the new Financial Information System, BPI will be insourcing accounts payable services, banking and administering payroll for the group of Companies. Although these costs will be allocated to each entity in keeping with their utilization, previously, those support services provided to Brantford Energy Corporation and Brantford Hydro Inc. and Brantford Generation Inc. by the City of Brantford were invoiced directly to those entities and were not reflected in the total costs of group services in Brantford Power Inc. Under the revised arrangements, the total costs will be reflected in Brantford Power Inc. but higher offset revenues will be recorded to represent the recovery of these additional services.

IR: 4-Energy Probe-37

Ref: Exhibit 4, Tab 2, Schedule 1

Please explain how BPI has allocated the costs for the Vice President of Customer Service and Conservation between the regulated utility and costs associated with CDM that are to be recovered from the IESO.

Response:

Please refer to the response to 1- Energy Probe- 6 a)

IR: 4-Energy Probe-38

Ref: Exhibit 4, Tab 2, Schedule 1

Please expand Table 4.2-G to include a column for actual data for 2012.

Response:

Please see Table 4-EP-38 below for the revised 4.2-G table including 2012 actuals:

	2012 Actuals	Last Rebasing Year - 2013- Board Approved	Last Rebasing Year - 2013- Actual	2014 Actuals	2015 Actuals	2016 Bridge Year	2017 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS
Number of Customers [2,4]	38,058	38,548	38,401	38,685	38,968	39,342	39,722
Total Recoverable OM&A from Appendix 2-JB	$ 7,812,674	$ 8,854,025	$ 8,789,985	$ 9,120,560	$ 9,112,116	$ 10,992,770	$ 10,470,506
OM&A cost per customer	$ 205.28	$ 229.69	$ 228.90	$ 235.76	$ 233.84	$ 279.42	$ 263.59
Number of FTEs [3,4]	56	58	58	54	56	63	65
Customers/FTEs	679.61	664.62	662.09	716.39	695.86	624.48	611.11
OM&A Cost per FTE	139,512.04	152,655.60	151,551.47	168,899.26	162,716.35	174,488.41	161,084.71

IR: 4-Energy Probe-39

Ref: Exhibit 4, Tab 4, Schedule 2

Please add lines to Table 4.4-D that shows the amount of total compensation that is capitalized and the resulting total compensation that is included in OM&A expenses.

Response:

BPI notes that, as already described, the historic compensation data is done on the basis of payments/cash flow rather than accruals, which is the basis for the presentation of capital and OM&A and therefore the calculation of revenue requirement. The capitalized labour is on an accrual basis, so this is not a completely consistent comparison.

BPI notes that there are additional allocations of labour costs which are not capitalized, most importantly allocations to billable work, which are excluded from the OM&A figures used to calculated the revenue requirement.

	2013 Board Approved	2013 Actuals	2014 Actuals	2015 Actuals	2016 Bridge Year	2017 Test Year
Number of Employees (FTEs including Part-Time)[1]						
Management (including executive)	16	16	15	13	17	17
Non-Management (union and non-union)	42	42	39	43	46	49
Total	58	58	54	56	63	66
Total Salary and Wages including overtime and incentive pay						
Management (including executive)	$ 1,963,909	$ 1,987,925	$ 1,744,347	$ 1,457,619	$ 1,773,992	$ 1,930,889
Non-Management (union and non-union)	$ 2,707,296	$ 2,740,403	$ 2,699,676	$ 2,974,712	$ 3,315,873	$ 3,602,016
Total	$ 4,671,205	$ 4,728,329	$ 4,444,022	$ 4,432,331	$ 5,089,865	$ 5,532,905
Total Benefits (Current + Accrued)						
Management (including executive)	$ 392,135	$ 396,931	$ 406,625	$ 393,215	$ 481,310	$ 473,778
Non-Management (union and non-union)	$ 653,960	$ 715,256	$ 734,650	$ 821,166	$ 960,923	$ 1,047,976
Total	$ 1,046,095	$ 1,112,186	$ 1,141,275	$ 1,214,381	$ 1,442,233	$ 1,521,753
Total Compensation (Salary, Wages, & Benefits)						
Management (including executive)	$ 2,356,044	$ 2,384,856	$ 2,150,972	$ 1,850,834	$ 2,255,302	$ 2,404,666
Non-Management (union and non-union)	$ 3,361,256	$ 3,455,659	$ 3,434,325	$ 3,795,878	$ 4,276,797	$ 4,649,992
Total	$ 5,717,300	$ 5,840,515	$ 5,585,297	$ 5,646,712	$ 6,532,098	$ 7,054,658
Capitalized Labour (including Benefits)		$ 664,409	$ 727,389	$ 902,479	$ 792,772	$ 673,763
Difference*		$ 5,176,106	$ 4,857,908	$ 4,744,233	$ 5,739,326	$ 6,380,895

IR: 4-Energy Probe-40

Ref: Exhibit 4, Tab 5, Schedule 1

a) Please provide a table that shows the decrease in shared services provided by the City of Brantford to BPI between 2016 and 2017.

b) Please provide a table that shows the increase in costs for BPI related to the services no longer provided by the City of Brantford.

c) If there are non-OM&A related expenses such as cost of capital, PILS and depreciation that are impacted by the movement to BPI of services previously provided by the City of Brantford, please provide a table showing the change in costs.

d) Please provide the business case for the transfer of the shared services that have been assumed by BPI from the City of Brantford.

Response:

a) Refer to Table 4-EP-40.a below for a table that shows the decreases in Shared Services provided by the City of Brantford in 2017 compared to 2016.
b) Refer to Table 4-EP-40.b for a table that shows the increase in costs for BPI related to the services no longer provided by the City of Brantford.
c) There are no changes in non-OM&A related expenses impacted by the movement of services provided by BPI that used to be provided by the City of Brantford.
d) The current Financial Information System (FIS) is a major problem for BPI and was identified as a priority project. There are significant gaps in the current systems, which result in high risk and complexities around business processes. As a result, these processes were inefficient and prevent BPI from a clear view of its operational costs from a detail and timeliness perspective. BPI considered the possibility of integrating the existing City of Brantford services using the new FIS (ie. payroll and AP) but the City of Brantford was not interested in their staff working on two systems. Consequently, to get the maximum benefits of an integrated FIS – transferring AP and Job costing to BPI was determined to yield the best outcome. BPI has minimized the work transferred in by contracting out managed payroll services to BDO using our FIS payroll module and BPI is working with RBC to have AP cheque issuance outsourced as well. BPI is expecting to absorb AP and Payroll services within Finance with no additional staff. Payroll outsourced costs are expected to be in the same magnitude of dollars BPI was paying the City of Brantford in addition to BPI having a fully integrated FIS in keeping with industry best practices.

Table 4-EP-40.a

2016 Shared Services					2017 Shared Services					
Name of Company		Service Offered	Pricing Methodology	Price for the Service	Name of Company		Service Offered	Pricing Methodology	Price for the Service	Difference
From	To			$	From	To			$	$
City of Brantford	Brantford Power Inc.	Accounts Payable	Cost-based	$ 55,823.00	City of Brantford	Brantford Power Inc.	Accounts Payable	Cost-based	$ -	$ 55,823.00
City of Brantford	Brantford Power Inc.	Payroll	Cost-based	$ 86,932.00	City of Brantford	Brantford Power Inc.	Payroll	Cost-based	$ 77,230.00	$ 9,702.00
City of Brantford	Brantford Power Inc.	Purchasing	Cost-based	$ 20,000.00	City of Brantford	Brantford Power Inc.	Purchasing	Cost-based	$ -	$ 20,000.00
City of Brantford	Brantford Power Inc.	Human Resources	Cost-based	$ 66,905.00	City of Brantford	Brantford Power Inc.	Human Resources	Cost-based	$ 68,243.00	$ (1,338.00)
City of Brantford	Brantford Power Inc.	Information Technology	Cost-based	$ 898,448.00	City of Brantford	Brantford Power Inc.	Information Technology	Cost-based	$ 916,417.00	$ (17,969.00)
City of Brantford	Brantford Power Inc.	Legal and Real Estate	Cost-based	$ 12,190.00	City of Brantford	Brantford Power Inc.	Legal and Real Estate	Cost-based	$ 12,434.00	$ (244.00)
City of Brantford	Brantford Power Inc.	Mailrun	Market-based	$ 7,674.00	City of Brantford	Brantford Power Inc.	Mailrun	Market-based	$ 7,827.00	$ (153.00)
City of Brantford	Brantford Power Inc.	Telephone Service	Cost-based	$ 8,580.00	City of Brantford	Brantford Power Inc.	Telephone Service	Cost-based	$ 8,752.00	$ (172.00)
City of Brantford	Brantford Power Inc.	Insurance and Risk Management	Market-based [premiums], Cost-based [Administration]	$ 110,822.00	City of Brantford	Brantford Power Inc.	Insurance and Risk Management	Market-based [premiums], Cost-based [Administration]	$ 113,038.00	$ (2,216.00)
City of Brantford	Brantford Power Inc.	Records Management	Market-based	$ 6,154.00	City of Brantford	Brantford Power Inc.	Records Management	Market-based	$ 6,277.00	$ (123.00)
City of Brantford	Brantford Power Inc.	Facility Asset Management	Cost-based	$ 218,469.00	City of Brantford	Brantford Power Inc.	Facility Asset Management	Cost-based	$ -	$ 218,469.00
City of Brantford	Brantford Power Inc.	Rental of Facilities-Office Space	Market-based	$ 140,597.00	City of Brantford	Brantford Power Inc.	Rental of Facilities-Office Space	Market-based	$ -	$ 140,597.00
City of Brantford	Brantford Power Inc.	Rental of Facilities-Office/Wareh	Market-based	$ 215,836.00	City of Brantford	Brantford Power Inc.	Rental of Facilities-Office/Wareh	Market-based	$ -	$ 215,836.00
City of Brantford	Brantford Power Inc.	Tree Trimming	Market-based [third-party services]; Cost-based [Administration]	$ 337,587.00	City of Brantford	Brantford Power Inc.	Tree Trimming	Market-based [third-party services]; Cost-based [Administration]	$ 344,339.00	$ (6,752.00)
Brantford Power Inc.	City of Brantford	Street Light Maintenance	Cost-based	$ 160,756.93	Brantford Power Inc.	City of Brantford	Street Light Maintenance	Cost-based	$ 171,205.56	$ (10,448.63)
										$ 702,863.58

Table 4-EP-40.b

	2016	2017
New AP Costs	83,729	107,054
Less Allocations to Affiliates	(30,397)	(37,395)
Total AP Costs to BPI	53,332	69,659
SLA costs incurred (AP & Payroll)	67,039	-
SLA costs saved(AP & Payroll)	-	67,039
Cost Increase after Allocation to Affiliates	53,332	2,620
Note: 2016 assumes an overlap between the new function and the SLA costs		

IR: 4-Energy Probe-41

Ref: Exhibit 4, Tab 7, Schedule 1

Are the regulatory costs associated with the current application of $29,160 in 2015 and $318,499 in 2016 included in the amounts shown in Table 4.1-A in 2015 and 2016? If yes, please indicate whether the full amounts are shown in Table 4.1-A or whether the amortized amounts are included in 2015 and 2016.

Response:

Please note the $29,160 related to 2015 is a budgeted rather than an actual amount estimated prior to the end of 2015. The amount shown in table 4.1-A for 2015 will include the actual expenses incurred related to the rate application in that year. The amount shown for 2016 in Table 4.1-A includes 1/5th of the expected $318,499 related to rate application costs for 2016. However, BPI expects to incur costs of $347,659 in total for the rate application and the amount for 2017 in Table 4.1-A includes 1/5th of the total expected costs of $347,659.

IR: 4-Energy Probe-42

Ref: Exhibit 4, Tab 7, Schedule 2

a) Please break out the $127,000 for OEB and intervenor costs associated with the current application between OEB costs and intervenor costs.

b) Please explain what the forecasted OEB costs are related to.

Response:

a) BPI considered its past experience with rate applications, as well as a quick survey of the regulatory costs included in the Applications of other LDCs in order to determine the $127,000. There was no break out considered between the OEB and intervenor costs.

b) BPI anticipates a component of the $127,000 will be associated with OEB costs related to the technical and settlement conference, and any witness/specialists the OEB has retained.

IR: 4-Energy Probe-43

Ref: Exhibit 4, Tab 9, Schedule 1

Please explain why BPI is forecasting a depreciation expense of $100,000 (Table 4.1-A) as a depreciation expense adjustment from loss on retirement of assets in the test year when no such adjustment is shown for any other year.

Response:

BPI is forecasting this loss as it pertains to the disposal of Poles (1830) and Transformers (1850). As per Chapter 2 Appendix 2-BA "Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately." Prior to 2017, loss on disposal is recorded into variance account 1575- IFRS-CGAAP Transition PP&E. From 2017 going forward, loss on disposal is grouped with amortization, therefore should be recorded into 5705- Amortization Expense.

IR: 4-Energy Probe-44

Ref: Exhibit 4, Tab 10, Schedule 1

The evidence states that BPI has actual loss carry forwards, but no loss carry forwards for regulatory PILS purposes because regulatory assets and liabilities have been included in the calculation of actual PILS while they are not included in the calculation of regulatory PILS.

a) Please provide a table that shows a reconciliation of the actual taxable income and actual regulatory taxable income that shows the impacts of the regulatory assets and liabilities and any other differences between actual and regulatory PILS.

b) What is the loss carry forward at the end of 2015?

c) Please provide a copy of the actual 2015 PILS filing.

Response:

a) The loss carry forward referred to in the written evidence resulted in 2014. The following two charts show a reconciliation of the actual taxable income and actual regulatory taxable income showing the impacts of the regulatory assets and liabilities and any other differences between actual and regulatory PILS for 2014 and 2015.

   For regulatory purposes, BPI was in a net tax payable situation for both 2014 and 2015.

2014 PILS impact of Regulatory Ajustments	**Income**		26.5%	**Tax Impact**	
Net Income/(Loss) as per T2 Tax Return		**(3,430,783)**			**(909,157)**
Adjusts to obtain Regulated Net Income:					
Add:					
CDM - Expenses	3,407,271			902,927	
Affiliated company Expenses	211,119			55,946	
Donations	2,000			530	
Actual Interest	2,309,228			611,945	
Interest Expense from DVA's	190,697			50,535	
Beginning Balance - Regulatory Assets	5,961,785	12,082,100		1,579,873	3,201,757
		8,651,317			2,292,599
Deduct:					
CDM - Revenues	3,407,271			902,927	
Affiliated Company Revenues	85,811			22,740	
Deemed Interest	1,983,521			525,633	
Interest Revenue from DVA's	75,796			20,086	
Ending Balance - Regulatory Assets	1,080,944	6,633,342		286,450	1,757,836
Net Income/(Loss) - Regulatory		**2,017,975**			**534,763**

2015 PILS impact of Regulatory Ajustments	**Income**		26.5%	**Tax Impact**	
Net Income/(Loss) as per T2 Tax Return		**3,274,218**			**867,668**
Adjusts to obtain Regulated Net Income:					
Add:					
CDM - Expenses	2,283,586			605,150	
Affiliated company Expenses	707,217			187,413	
Donations	2,150			570	
Actual Interest	2,258,564			598,519	
Interest Expense from DVA's	32,289			8,557	
Beginning Balance - Regulatory Assets	1,080,944	6,364,750		286,450	1,686,659
		9,638,968			2,554,326
Deduct:					
Adjustments related to IFRS for tax purposes	847,905			224,695	
CDM - Revenues	2,537,140			672,342	
Affiliated Company Revenues	410,229			108,711	
Deemed Interest	2,007,299			531,934	
Interest Revenue from DVA's	70,033			18,559	
Ending Balance - Regulatory Assets	1,606,408	7,479,015		425,698	1,981,939
Net Income/(Loss) - Regulatory		**2,159,953**			**572,388**

b) The loss carry forward at the end of 2015 is $159,164 which BPI anticipates will be used fully when filing its 2016 tax return.

c) A copy of the actual 2015 PILS filing has been provided as Attachment 4-EP-44-A.

It should be noted that during the course of this analysis BPI submits that the ROE for 2014 and 2015 have been overstated by the tax impact of the loss carry forward. The adjusted ROE for 2014 and 2015 is 9.98% and 8.97% respectively. BPI believes loss carry forward should be removed from the calculation of regulated ROE because it is related to pass through timing differences and deductions for non rate funded costs.

IR: 4-Energy Probe-45

Ref: Exhibit 4, Tab 10, Schedule 1

a) For each of the positions eligible for the apprenticeship tax credit in 2015 and/or 2016, please confirm that the 48 month eligibility does not extend into the 2017 year. If this cannot be confirmed, please provide details on the expiry date.

b) Does BPI have any positions that qualify for the co-operative education tax credit or the federal job creation tax credit? If yes, please provide details.

Response:

a) BPI confirms that the 48 month eligibility does not extend into the 2017 year. The eligibility end date is in 2016.

b) No, BPI does not have any positions that qualify for the co-operative education tax credit or the federal job creation tax credit.

IR: 4-Energy Probe-46

Ref: Exhibit 4, Tab 10, Schedule 2

a) Please explain the loss of $100,000 due to asset disposals increases taxable income.

b) Does the net income before taxes reflect the above noted loss of $100,000? If not, please explain why not.

c) Please explain why there is a deduction of only $15,000 related to disposal of assets.

Response:

a) This loss pertains to the disposal of Poles (1830) and Transformers (1850). As per Chapter 2 Appendix 2-BA "Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately." BPI has therefore included the loss of $100,000 as a separate item in depreciation as required.
b) Yes, the net income before taxes reflects the above noted loss of $100,000 as it is included in depreciation expense.
c) For 2017, loss on early disposals is included in amortization line within Table 4.10.2-A: Tax Calculations. Refer to the response for a) above.

IR: 4-Energy Probe-47

Ref: Exhibit 4, Tab 10, Schedule 2

Please confirm that bottom line in Table 4.10.2-B for property taxes are amounts that have been included in the OM&A figures shown in Table 4.1-A. If this cannot be confirmed, where are these costs included in the revenue requirement?

Response:

BPI is withdrawing its request for building funding, and therefore does not have any property taxes associated with the building. However, there is $20,031 in property taxes associated with land that holds BPI's Distribution, Station, Building and Fixtures. This amount was included in the OM&A figures shown in Table 4.1-A. BPI has since then remapped the Property Taxes of $20,031 to 6105- Taxes Other Than Income Taxes.

IR: 4-Energy Probe-48

Ref: Exhibit 4, Attachment 4-G & Exhibit 2, Tab 1, Schedule 1

a) Please explain why the additions to CCA shown for the 2014 historical year in the PILS filings are \$2,612,998, while in the fixed asset continuity schedule, the additions are \$2,794,244.
b) Please explain why the additions to CCA shown for the 2015 historical year in the PILS filings are \$3,857,084, while in the fixed asset continuity schedule, the additions are \$4,111,311.

Response:

a) The additions to CCA shown for the 2014 historical year in the PILs filings does not include \$181,246 in additions, as these additions are for land rights, and capital contributions which are included in Schedule 10 (CEC) as opposed to Schedule 8 (CCA).

b) The additions to CCA shown for the 2015 historical year in the PILs filings does not include \$254,227 in additions, as these additions are for land rights, and capital contributions which are included in Schedule 10 (CEC) as opposed to Schedule 8 (CCA).

IR: 4-Energy Probe-49

Ref: Exhibit 4, Tab 10, Schedule 1

What is the impact, if any, of the changed noted with respect to transferring the CEC balances to Class 14.1 on the 2017 taxable income?

Response:

Based on BPI's review of the proposed changes, it does not anticipate an impact on 2017 taxable income with regards to transferring the CEC balances to Class 14.1.

IR: 4-SEC-17

[Ex.4]
Please add a column appendix 2-JC to the following appendices that show year-to-date actuals for 2016.

Response:

Refer to Table 4-SEC-17 below for June 2016 year-to-date actuals.

Programs	Last Rebasing Year (2013 Board-Approved)	Last Rebasing Year (2013 Actuals)	2014 Actuals	2015 Actuals	2016 Bridge Year	2016 YTD Actuals (June)	2017 Test Year	Variance (Test Year vs. 2015 Actuals)	Variance (Test Year vs. Last Rebasing Year (2013 Board-Approved)
Reporting Basis	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	CGAAP
Operations									
Operation of Distribution Station	31,853	30,865	36,340	37,056	40,499	21,059	40,547	3,491	8,694
Transformer Substations	146,932	141,746	116,684	91,145	109,941	46,740	108,953	17,808	- 37,979
Overhead Distribution Lines/Feeders	15,917	17,225	49,047	20,970	29,956	15,940	29,105	8,134	13,187
Underground Distribution Lines/Feeders	74,881	89,367	96,998	103,296	140,982	40,743	141,121	37,825	66,240
Load Dispatching	35,013	38,568	86,328	59,730	123,751	33,696	122,569	62,839	87,556
Miscellaneous Distribution	248,655	248,607	329,871	282,173	304,627	72,222	289,039	6,866	40,385
Distribution Meters	317,336	260,782	276,540	307,904	321,158	104,904	324,178	16,273	6,842
Customer Premises	1,000	1,746	986	325	1,549	389	1,495	1,170	495
Supervision	47,509	465,017	451,091	427,083	329,851	236,589	325,894	- 101,189	278,385
Stores/Fleet/Property Allocations	313,835	146,441	125,675	221,353	295,649	147,825	250,893	29,540	- 62,942
Sub-Total	1,232,931	1,440,365	1,569,559	1,551,035	1,697,963	720,107	1,633,794	82,759	400,863
Maintenance									
Supervision	482,238	259,237	519	81,810	-	74,532	-	- 81,810	- 482,238
Overhead Distribution Lines/Feeders	438,677	414,393	393,459	467,727	589,852	153,497	592,238	124,511	153,561
Underground Distribution Lines/Feeders	401,289	373,731	414,059	399,569	420,305	151,979	410,401	10,832	9,112
Maintenance of Poles, Towers & Fixtures	27,822	42,529	110,187	45,938	86,014	13,356	86,284	40,345	58,462
Line Transformers	200,172	73,543	134,026	23,440	71,659	8,325	69,311	45,871	- 130,861
Miscellaneous	4,058	6,298	15,342	10,841	14,481	6,395	11,854	1,013	7,796
Tree Trimming	381,218	376,223	320,062	362,950	337,587	120,437	344,339	- 18,611	- 36,879
Stores Allocations	111,858	356,751	280,500	170,594	92,343	46,172	108,657	- 61,937	- 3,201
Sub-Total	2,047,331	1,902,706	1,668,155	1,562,869	1,612,241	574,693	1,623,083	60,215	- 424,248
Customer Service									
Billing/Supervision	1,511,931	1,491,525	1,741,949	1,889,897	2,061,433	864,512	1,879,282	- 10,615	367,351
Meter Reading	408,000	394,460	367,529	471,575	435,837	268,164	419,175	- 52,400	11,175
Collections	319,900	334,188	396,565	383,638	436,340	198,147	490,223	106,585	170,323
Bad Debts	319,000	357,273	366,783	95,284	300,000	140,780	300,000	204,716	- 19,000
Community Relations	97,000	37,976	10,279	11,505	16,585	2,187	17,390	5,885	- 79,610
Sub-Total	2,655,831	2,615,421	2,883,104	2,851,899	3,250,195	1,473,790	3,106,070	254,171	450,239
Administration									
Administration Wages/Employee Benefits	2,240,931	2,470,208	2,215,474	2,238,470	2,979,215	1,554,365	2,689,113	450,642	448,181
General Administration	179,000	234,429	239,423	220,824	257,017	102,896	263,468	42,644	84,468
Outside Services Purchased/Insurance	274,000	411,948	355,218	582,413	1,003,897	67,120	886,731	304,318	612,731
Regulatory Expenses	224,000	250,943	189,627	104,606	192,242	126,975	268,247	163,641	44,247
Smart Meter Contra	-	- 536,035	-	-	-	-	-	-	-
Sub-Total	2,917,931	2,831,493	2,999,741	3,146,313	4,432,371	1,851,356	4,107,559	961,246	1,189,627
Miscellaneous	-	-	-	-	-		-	-	-
Total	**8,854,025**	**8,789,985**	**9,120,560**	**9,112,116**	**10,992,770**	**4,619,946**	**10,470,506**	**1,358,390**	**1,616,481**

IR: 4-SEC-18

[Ex.4-2-1, p.8]
With respect to the Financial Information System project, please:

a. Provide an update on the status of the project.
b. Provide the project business case.
c. Provide a copy of the RFP.
d. Detail and provide the annual OM&A savings that will be achieved in 2017 and onwards due to the migration to the new Financial Information System.
e. Provide a breakdown of the Annual support/hosting fees.

Response:

a) BPI completed the planning phase of the project with the short listed vendor ('preferred vendor') in May 2016 and completed the contract negotiations by mid June 2016. On June 17, 2016, BPI signed a final Master Services Agreement (MSA) which encompassed procurement of software licenses, hosting facilities, hosting services and implementation services for the FIS solution. BPI has commenced the design phase of the project on June 20, 2016 and as of August 18, 2016, BPI has completed a number of the design phase activities working with the preferred vendor (and their methodology and approach), including:

- Application walkthrough sessions completed by July 8, 2016
- Application design sessions completed July 28, 2016
- Data conversion design sessions are in progress
- Integration design sessions are completed and integration specifications document is being developed
- To-be process flow reviews are under way and expected to complete by early September 2016. Design books that document the outcome of design sessions are being drafted by the preferred vendor and plans for BPI to review the design books in early September 2016.
- Environment setup and application installations are largely complete.
- Overall, all design phase activities are planned for completion by late September 2016 and BPI and the preferred vendor do not see any issues or significant risks that could affect the completion of these activities in the timeline planned.

b) BPI investment in FIS is expected to bring a number of opportunities through an integrated system encompassing all finance functions and supported by a robust budgeting and reporting engine.
Current key gaps:

- BPI uses the City finance system (JD Edwards) which is not designed or configured for a local distribution company but for a municipal corporation. Any changes to the system are governed by the overall City technology direction with little influence or potential to tailor the system for BPI business needs. Although this model has worked so far (both as a solution and financially), BPI is looking to move to better systems tailored to the LDC business and minimize manual work
- Currently, finance functions are performed in multiple systems (JD Edwards, Daffron, spreadsheets) with loose or no integration between systems. This causes duplicate efforts in data entry, additional effort to reconcile data between errors and tends to be error prone.
- Further, a number of these processes (example, indirect cost allocations) are performed manually or in spreadsheets and with a potential for errors, requiring additional effort to review.

As a result of the above, BPI experiences significant delays in closing the books and finalizing accounts for external reporting or management analysis. Very limited management information reporting is available due to the poor timeliness of information. Also, BPI staff is often required to work extra hours at times of peak finance/accounting activity (such as year-end closing, budget finalization, support to OEB rate application filings, etc.).

Investment in the FIS is expected to incorporate within the FIS a number of finance related functions that are currently being performed outside, automate some of the manual calculations and allow the finance team to focus on more on value added analysis and supplying management timely information instead of spending time on reconciling numbers in multiple systems, performing manual calculations and other low value work.

BPI has never invested in a financial system and relied on the City systems to carry along the operations. This investment and the on-going costs to maintain will bring greater control and ownership over the FIS solution by BPI and BPI's ability to respond and report to its various stakeholders. Some savings are expected in the service level agreement (SLA) costs that BPI currently pays to the City but these are marginal, since the current City systems have been stable with minimal changes. These costs are expected to bring productivity gains in the longer run but are difficult to quantify.

A detailed business case for the project was initially documented in the report delivered as part of the Systems Integration Study (SIS) performed in 2013 by an independent consultant (Util-Assist) hired by BPI. Excerpt from the report relating to FIS business case below:

"5.5.4 FIS Gaps, Opportunities and Recommendations

5.5.4.1 Overlap: Payroll Requires Additional TAPS System

The multitude of union contracts being managed by the City has created a need for the City to use a Business Intelligence (BI) system (i.e., the TAPS system) to ensure that the payroll information gets into

JDE accurately. For example, TAPS ensures that allowable hours are not exceeded and manages the setup of personnel and associated rates of pay for the union contract.

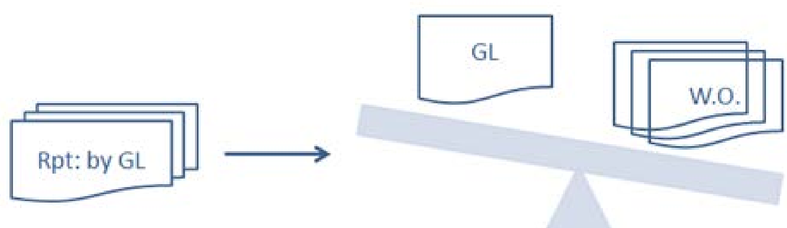
The BPI environment is less complicated and does not require the BI tool used by the City. Likewise, the standard process implemented at like-size utilities is to enter payroll information directly into the FIS. Implementing a Workforce Management (WFM) system is recommended as a project (Project C3) to simplify the payroll process by addressing gaps due to a manual process. Streamlining the payroll process is an opportunity for BPI; however, it involves added integration to the TAPS system, which makes business case justification for the project that much more difficult.

5.5.4.2 Overlap: Duplication of Data and Functions in the FIS and the CIS

There is duplication of data and functions in the CIS and FIS. Resources are required to manage and review data multiple times. There is only a small amount of actual integration between the CIS and FIS which results in significant use of other software packages as "holding programs" (e.g., Excel). Managing data outside of core systems is not a best practice, and depending on the data being managed, can introduce security related concerns. As technology evolves, strong security protocols are becoming more important, and any security audits would identify issues in BPI processes. Utilities have started to address these gaps by incorporating these concepts into their governance model for managing data: core systems should manage data securely and not require holding programs to create reports or facilitate other analysis.

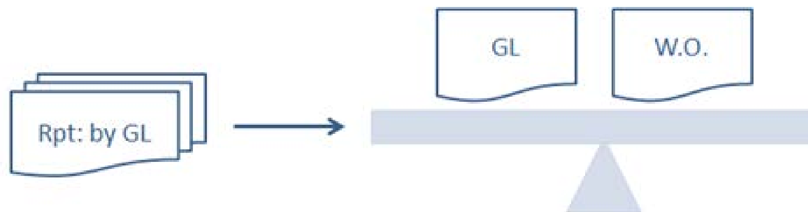
5.5.4.3 Gap: Work Orders

While this process is Engineering-related, the difficulties with the process are the result of the use of multiple systems for managing information that would normally be managed within a single FIS system.

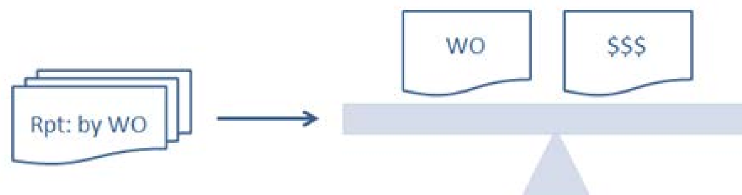


The BPI Engineering Department creates many different work orders to capture the work and associated costs that can result from different capital projects. Due to the lack of integration between systems (i.e. the use of two financial systems, each with a different purpose and containing different data), the balancing of GL accounts with the associated work orders requires more manual intervention than normally required. The verification and reconciliation efforts are time-consuming, and complicated enough that senior Finance resources are required. This situation creates risk from a couple of different perspectives: senior Finance resources should be spending their time analyzing data rather than managing reporting functions; and if the senior resources were to depart or move into a new role, it would be exceedingly difficult to train new resources.

Due to the complexity involved in managing many work orders for a single GL, there is incentive from a Finance perspective to use a single work order for each GL account. Having a single work order that matches a GL number eases the process of balancing data between the financial system (JDE) and the system containing work order information (Daffron).



The difficulty that is encountered by the Engineering Department with this reporting process (one-to-one: GL and work order), is that capital projects may require different types of "time and materials." For example, work associated with installations of "overhead" include different amounts of labour and different material than installations of "underground" work. From a budgeting perspective, the Engineering Department would prefer to have (where appropriate) many work orders, and Finance reports by work order (rather than GL) to allow more granular analysis of costs, leading to (not only) improved processes related to budgeting, but also more accurate estimates that can be provided to customers during the request for service process. Additionally, the detail provides the required data to reconcile "estimate to actual," and this can help ensure that BPI is not subsidizing others in the economic evaluation process or vice versa.



In addition, there is difficulty producing the reporting that would benefit Engineering in the tracking of capital projects. As progress on capital projects evolves, best practices would suggest that Finance provide Engineering with status reports so that Engineering can see monies spent as compared to projected costs. Consistently-provided feedback will improve the process, allowing Engineering to better understand the financial status of ongoing projects. Difficulties are encountered using the current process to achieve this result due to the use of disparate financial systems (i.e., separation between financial reporting in JDE and job costing information in Daffron). Best practices within the Ontario LDC environment dictate that the work order system is an integrated part of the financial software. Currently, Finance occasionally encounters issues assigning work order information to projects due to the use of different numbering systems in each product. The descriptions used by Finance (i.e., JDE) are not available to the Engineering group, as Engineering is only exposed to the Daffron product.

The management of work orders includes the use of payroll and inventory information, and this consequently contributes to the job costing, accounts payable and accounts receivable processes. Work orders are used to manage the "maintenance" of the distribution system, and therefore effective management of work orders is critical in such important LDC functions as capital planning and the maintenance of system reliability, all of which is captured in the cost allocation/rate recovery process.

5.5.4.4 Gap: Job Costing

The Engineering Department works with potential customers to develop designs and cost estimates for new construction. When designs are created in the design tool (i.e., AutoCAD), Engineering requires access to information regarding inventory and the associated costs for products, as well as accurate estimates of labour requirements. The best practice approach for the use of CIS, is for consumption billing, with an integration to provide totals to FIS. FIS then becomes the system of record for inventory, work orders, payroll, accounts payable and accounts receivable. All of the FIS functions become important considerations in the Engineering job costing process. Engineering becomes an internal customer to the FIS, requiring inventory data to estimate the costs of material for a new project. The department requires reporting from Finance that associates payroll information with work orders, in order to understand the true labour costs to install the material. Finance is normally able to report on these totals by managing accounts payable (i.e., purchase of material), and accounts receivable (i.e., invoicing of completed jobs to refine the costing of future projects).

5.5.4.5 Gap: Capital Planning

In addition to the job costing component of the capital planning process, Engineering depends on financial reporting to understand "budgeted costs" as compared to "actual costs" as projects are completed over the course of the year. The same problems that are introduced to the job costing process by the current use and duplication of FIS and CIS also result in a reporting process that requires much more work by both Engineering and Finance. By tracking work orders and labour in different systems for different purposes, reporting becomes difficult and requires a great deal of effort to reconcile the differences between systems.

5.5.4.6 Overlap: Accounts Payable (AP)

The accounts payable function illustrates the difficulties that result from the use of two FIS systems. BPI Finance staff must set up vendors in Daffron because inventory is managed in Daffron; however, vendors must also be established in JDE in order to generate payments. There is some integration to streamline the management of vendor numbers; however, the City controls the vendor numbers and restricts BPI from using the Daffron number in JDE, resulting in a mapping of vendor numbers between the two systems. Where vendor numbers differ the Finance team uses the "mapping" spreadsheet to resolve the exceptions. The result is a duplication of effort: entry of the vendor information in both systems, as well as a requirement to track the vendor numbers in a "mapping" spreadsheet.

6.5.4.7 Gap: Budget Cycle

As noted above, the Finance Department provides Engineering with updated budget numbers throughout the year. This is also a requirement for all departments: to receive updated financial information pertaining to the departmental budget. The Finance team does their best to provide this, but *the information is not provided as frequently as most departments (including Finance) would like. This is due to the difficulty encountered in completing daily processes. Additionally, when Finance is able to perform this important function, the use of two financial systems creates a requirement to update budgetary information in Microsoft Excel, rather than generating status reports from the FIS. This is because information is required from both systems, and the data must be reconciled and made useful for analysis by the departments.*

5.5.4.8 Gap: FIS Reporting

The Finance Department has cited difficulties in reporting functions, including providing reports to other departments. At present, Finance team expertise is required to provide data, due to the convoluted use of the two FIS systems. Examples of reporting processes that could be improved include:

Budget-to-actual reports

Regulatory reporting

Indirect Allocations

Regulatory assets

Bank reconciliation

Financial statements

FIS reporting is also required for the BPI Board and the OEB.

5.5.4.9 Gap: Lack of Proper Auditing in Excel

There is "risk" involved in the use of Microsoft Excel; in addition to communicating sensitive information in an insecure format and the problems associated with version control, there is risk that the accuracy of reports could be compromised because complex calculations are not "audited" in Excel in the same way that automated functions in a FIS would be audited for accuracy.

5.5.4.9.1: Opportunity: Consolidate Data and Functions into a Single FIS

BPI has the opportunity to significantly improve Finance department business processes by consolidating finance data and functions into a single FIS. The requirement needs to be considered in conjunction with any decisions about the CIS.

5.5.4.9.2: Recommendation: Project F1

PROJECT F1 ***Procure a Financial Information System (FIS)***				
Scope Development		***Dept.***	***Cost***	***Start***
F1-1	*Update business processes that involve FIS*	*Fin*	*10 days (Fin)*	*Q1 2014*
F1-2	*Use business processes to document requirements*	*Fin*	*5 days (CS)*	*Q1 2014*
F1-3	*Build RFP document*	*Reg*	*10 days (Reg)*	*Q3 2014*
F1-4	*Build scoring template (scoring spreadsheet, scoring document)*	*Reg*	*5 days (Reg)*	*Q2 2014*
F1-5	*Release RFP to market and evaluate responses prior to end of quarter*	*Reg*	*1 day (Reg)*	*Q1 2014*
F1-6	*Receive responses and complete evaluation (including vendor negotiation). Create decision document.*	*Reg*	*0.5 – 1 day per response, per evaluator* *3 days to complete documentation (Reg)*	*Q2 2014*
F1-7	*Announce decision; begin discussion with vendor regarding rollout, which should be completed by end of 2015*	*Reg*	*1 day (Reg)*	*Q2 2014*
F1-8	*Move to production processes on new FIS*	*NA*	*NA*	*Q2 2015*
F1-9	*Provide notice to City of Brantford that BPI is moving to new FIS*	*Reg*	*1 day (Reg)*	*Q2 2015*

Business Case for Project F1

FIS conversion is required to move BPI Finance to a standard approach to handling financial business processes. The current situation requires Finance resources to use complicated processes to acquire data from disparate systems and analyze data outside of systems. Effective management of the processes outlined in this section cannot be overstated. Traditionally, LDCs manage all of these functions in a single FIS, which is why the FIS project is identified as such a high priority. Any integration between JDE and Daffron could simplify the process, but this would merely be a "stop-gap" solution to a larger problem; incremental efforts will not suffice. The true resolution to the problem is to follow best practices and use *the systems in the way in which they are intended. A new FIS will have a cascading effect across the organization, resulting in improvements to many processes across other departments, such as the Engineering Department's job costing and capital planning processes. However, these costs are "soft" costs realized through efficiencies, which can be hard to quantify during business case development.*

The FIS RFP process can lead to a formal business case that can compare JDE's quotation for their products and services against the offerings of other vendors in the market. (During the discovery process, City personnel provided a best guess on the current costs of the system, which are considerably higher than what like-size utilities would pay for FIS.) In addition, as stated in the CIS procurement section, the labour costs for the Daffron expertise that is covered in the SLA with the City should be considered in the business case. With a more standard approach to managing the FIS, these resources may not be required, providing a cost savings that can contribute to a positive business case.

Business Decisions for Project F1

BPI needs to embrace best practices on business process documentation and use of service orders, as this documentation becomes critical during technology procurements.

Risks for Project F1

Implementing a new FIS can introduce the risk of higher costs, but due to the business process situation that is created by two FIS systems, BPI is almost certainly going to see reductions in cost due to the efficiencies. The current situation— with regards to business process—creates significant risk to the organization; training new staff on existing processes would be extremely difficult, leaving BPI with very little redundancy in the Finance team. Moving to a more standard approach should be considered a high priority."

c) See attachments:

   4-SEC-18-c.1 FIS-RFP.zip – contains the RFP issued and appendices that accompanied the RFP

   4-SEC-18-c.2 FIS-BAFO.zip – contains the Best-And-Final-Offer (BAFO) document, which was issued to two short listed proponents based on an evaluation of the RFP responses from the proponents. The BAFO was designed to get further information and a final offer for BPI consideration and final selection.

d) BPI has never invested in a financial system and relied on the City systems to carry along the operations. This investment and the on-going costs to maintain will bring greater control and ownership over the FIS solution by BPI and BPI's ability to respond and report to its various stakeholders. Some savings are expected in the service level agreement (SLA) costs that BPI currently pays to the City but these are marginal, since the current City systems have been stable with minimal changes. These costs are expected to bring productivity gains in the longer run but are difficult to quantify.

It is not practicable to measure all the benefits in monetary terms. A lot of the benefits will be in terms of better timing of information, more time to perform meaningful analysis, greater confidence in the numbers/information from the system and better service/visibility to the internal and external business stakeholders/ consumers of financial information.

Below table provides a breakdown of the estimated annual support and hosting fees. Both amounts were estimated based on the quote received from the preferred vendor as part of the RFP responses, BAFO and subsequent negotiations (until April 2016 – the time of filing of this rate application):
e) Below table provides a breakdown of the estimated annual support and hosting fees. Both amounts were estimated based on the quote received from the preferred vendor as part of the RFP responses, BAFO and subsequent negotiations (until April 2016 – the time of filing of this rate application):

Expense	Detail/basis for estimate	Annual Amount
Annual enhancement fee	Annual fees charged by the software vendors to allow access to software updates, releases and upgrades. This fee is a percentage of the software license cost and is due annually.	$114,631
Annual hosting charges	Annual charges for hosting the FIS application. These charges are due monthly.	$52,800
Total		**$167,431**

IR: 4-SEC-19

[Ex.4-2-1, p.10]
Please provide a copy of the System Integration Study.

Response:

Please refer to Appendix 13 of BPI's Distribution System Plan, included with Exhibit 2. For greater clarity, this can be found on page 716 of 932 in the PDF document of Exhibit 2.

IR: 4-SEC-20

[Ex.4-2-1, p.10]
With respect to the Customer Information System Project, please:

a. Provide an update on the status of the project.
b. Provide the project business case.
c. Provide a copy of the RFP.
d. Detail and provide the annual OM&A savings that will be achieved in 2017 and onwards due to the migration to the new Financial Information System.
e. Provide a breakdown of the Annual support/hosting fees.

Response:

a) BPI response:
   - BPI has prepared an initial draft of the RFP for the new CIS system.
   - BPI had decided to place the RFP was on hold until BPI had completed the procurement of the new FIS system. This will allow BPI to apply the learnings from the FIS procurement and also evaluate ways to adopt common infrastructure or other facilities.
   - With the completion of the FIS system procurement in June 2016, BPI has revived the efforts to review and finalize the RFP for the new CIS. Currently, BPI is performing this review and expects to issue the RFP to the market by early to mid- October 2016.

b) BPI investment in CIS is expected to bring a number of opportunities by creating a foundational customer service platform that is well supported, incorporates best practices in the Ontario LDC market and allows BPI the systems flexibility and nimbleness to adapt to changes in the environment (regulatory, customer service driven, competitive etc.).

   Current key gaps:

   i. BPI uses the Daffron CIS Version 5 which is over 25 years old, highly customized and at risk of running out of vendor support.

   ii. current Daffron platform does not easily support “a ‘robust’ customer care engagement package”, including the integration with proposed peripheral services (such as e-services) without extensive vendor and internal customization. A number of Ontario LDCs that used Daffron have migrated to other CIS platforms due to this reason (compounding the risk of in #i above)

   iii. current Daffron system is not intuitive or easy to use/learn, does not use a graphical user interface (GUI) and requires a high level of support (higher effort and costs to maintain/upgrade/enhance/modify) than some of the alternatives in the market that use a more current technology platform

As a result of the above, BPI currently requires longer timelines and greater effort to modify the current Daffron system and test the system for changes (example, programs such as OESP, removal of debt retirement charge, clean energy etc.). Any changes due to regulatory or environmental changes (that impact all LDCs in the Ontario LDC market) need to be programmed into the current Daffron CIS system by BPI's Daffron programmers; BPI is unable to avail of software vendor supplied updates in a timely manner (primarily due to the older version / current vendor updates).

Investment in a new CIS is expected to allow BPI to adopt a system that is more commonly used in the Ontario market and avail of updates/releases from the vendor at least for some, if not all, updates. BPI can gain better confidence and reduce the risk of an unsupported system. Further, BPI may be able to avail opportunities to collaborate with other Ontario LDC/s on the same CIS platform and share system wide best practices and potentially share costs of changes where such changes are required for all such LDC/s.

A new CIS is expected to be a more robust service offering to customers, including expanded self-service options and improved communication to customers.

This investment in a new CIS system and the on-going costs to maintain will bring better ability to respond to changes, enhanced customer service ability, better responsiveness and timely updates to customers.

It is not practicable to measure all the benefits in monetary terms.

BPI expects approximately $100,000 to $150,000 in annual savings starting 2018 on the service level agreement (SLA) costs that BPI currently pays to the City for Daffron support. In addition, the new CIS system is expected to bring a number of benefits, which are difficult to quantify, such as:

- qualitative benefits outlined above,
- reduced development costs to meet regulatory/industry requirements
- reduced foreign exchange risk as current Daffron support charges are in US dollars
- productivity gains in the longer run

The initial business case for the CIS was documented in the System Integration Study (SIS) report submitted by Util-Assist, in 2013-14. Below is an excerpt from the Util-Assist SIS report on the Daffron CIS:

"Daffron and Associates, founded in 1976, is a privately-owned, family-run business based in Bowling Green, Missouri. Daffron's current head count is 70 employees, with four employees

based in Canada (Hamilton office): one project manager and three programmers. The project manager coordinates Canadian user-group meetings to gather requirements, and additional staff are recruited from the head office as required. Daffron also maintains a Fayetteville, Arkansas office; with recently expanded office space, the company plans to hire additional Java programmers at this location. Daffron has a total of 102 customers across the U.S., Ontario, and the Caribbean.

BPI currently uses Daffron version 5, which offers a command line interface ("green screen"). However, Daffron Version 5 is nearing end-of-life, and BPI will soon be faced with the decision to migrate to Daffron iXp. So far, over 60 Daffron customers have migrated to the iXp platform, consisting of half of the Daffron install base.

The iXp solution introduces a GUI front end and employs open architecture, providing interoperability across third-party applications. Daffron created the new interface by developing the front end in Java; however, iXp still contains extensive RPG programming and the back end of the solution remains the IBM iSeries. It is important to consider that this aging technology may present a risk in finding skilled resource; moreover, other CIS vendors, such as Oracle, are already well ahead of Daffron in terms of emerging technologies and interfaces. Daffron's long term goals are to achieve platform and database independence, but no changes are planned for the next five years.

BPI uses the Daffron CIS as the source of data for customer information and to facilitate the consumption billing process. In addition to these standard uses for utility CIS, Daffron plays a part in the following BPI functions:

- *Inventory management (poles, transformers, wire, etc.)*
- *Work order management*
- *Service order management*
- *Job costing*
- *Maintaining meter-to-transformer relationship as meters and transformers change*
- *Payroll and benefits (time and cost recorded through the City TAPS application, then used in Daffron for work order tracking)*
- *Accounts receivable (work orders tracked in Daffron for billing as miscellaneous A/R in FIS)*

The BPI instance of the Daffron system has provided a CIS solution to BPI for more than 25 years. With onsite programmers (sourced under the City Service Level Agreement or SLA services) *to enhance the system as requirements evolve, the system has allowed BPI to implement significant changes, such as TOU billing and Arrears Management. While the vendor has successfully met the requirements for the regulatory environment in which BPI exists, the system currently being used by BPI has become "aged." Perhaps more significantly, the degree of customization that is present in the BPI instance has created complications in the upgrade process.*

The BPI Daffron CIS consists of a core application, with a layer of Ontario-specific customizations to meet Ontario regulations and requirements, as well as libraries of custom code specific to BPI. Although some Ontario customers have upgraded other Daffron systems to iXp, none have upgraded their CIS systems yet, and the timeline for delivering the Ontario core layer is still being determined.

In upgrading to iXP, BPI would need to review all custom programs, as any programs that interface with a screen or affect the flow of the application will need to be modified or rewritten. Once the programs have been migrated, BPI will be required to convert the data, and then conduct thorough testing and train staff on the new interface.

Very little integration exists between the CIS and other downstream systems. Thus far, integration requirements have (generally speaking) been accommodated through customized reporting from CIS, and where required, the export of data into "holding programs," like Microsoft Excel, where users work with data before importing the data into the required system. This scenario creates many opportunities for enhancements to the existing processes.

With the introduction of TOU billing, and the evolving regulatory landscape in Ontario, CIS systems have continued to evolve, and many LDCs in the market have "refreshed" their CIS platforms, or even changed vendors in recent years. The integration to IESO MDM/R resulted in CIS development (or customization), and the implementation of smart meters has resulted in a need to integrate more systems with CIS to take advantage of the data that is being transmitted by the new metering technology. For example, it has become important to maintain an electrical connectivity model that includes the meter-to-transformer relationship and provide this model to downstream systems, such as the Operational Data Store, the Outage Management System, and Engineering analysis tools. More generally, smart meters have driven utilities to use systems that easily support integration without the need for custom programming by exposing Service Oriented Architecture, and introducing the concept of workflow automation to streamline processes. While the existing Daffron product provides a cost-effective solution for core CIS functions, BPI should consider the limitations of the system in the context of the larger goal of leveraging technology to implement efficiencies."

Further Util-Assist recommends:

Critical opportunities for improvement include the following systems procurement and integration efforts:

….

- *Improve CIS processes by going to market for a CIS…*

….

- *Streamline processing of meter data exceptions, through integration of CIS with ODS to achieve "service order integration"*

"Util-Assist is confident that if BPI were to "survey" like-sized utilities in the Province-particularly utilities that have more advanced governance models for the management of data and information that can lead to the implementation of "off the shelf" products-they would find that most other utilities do not require a dedicated CIS support staff of the same size as is currently covered by the SLA with the City of Brantford. This may present BPI with a cost savings that can contribute to a positive business case."

In addition, based on BPI research / survey of Ontario LDCs, there are only 5 LDCs (out of 43 surveyed) that use Daffron. 4 of those 5 utilities, including BPI, are small/mid-sized (about 10,000 to 70,000 customers) and only one is a large LDC (over 200,000 customers). Our understanding is that all the Ontario LDCs are using the older version of Daffron where some Ontario specific regulatory reporting functionality is available. The new iXP version does not have the Ontario specific regulatory support built yet and the possibility/timing of this build is unclear.

Further, in late 2015, the one large LDC using Daffron in Ontario has announced merger with other like sized LDCs. Pursuant to the merger, there is a likelihood that the large LDC will discontinue use of Daffron and migrate to a common system that the merged entity chooses as their CIS platform. There is a risk that there will be little market share left for Daffron in Ontario to provide timely and regular regulatory updates putting BPI at further risk on the dated solution.

Furthermore, the current Daffron platform does not easily support "a 'robust' customer care engagement package", including the integration with proposed peripheral services (such as e-services) without extensive vendor and internal customization. A decision on a CIS will provide a vision and a roadmap toward integrated enterprise systems and "create a sense of 'certainty' which is required to move forward concurrently with other integration projects." A fully supported and scalable CIS that meets evolving business and regulatory needs is an expected outcome of the project, along with up-to-date business process documentation and clear process ownership.

c) BPI response:
BPI has not issued an RFP for the CIS to the market yet. BPI targets to issue this RFP by early to mid-October 2016. A draft copy has been drafted and is currently being reviewed by the Customer Service, Billing, Technology and Procurement teams.

d) BPI response:
See Project business case response above. BPI expects approximately $100,000 to $150,000 in annual savings starting 2018 on the service level agreement (SLA) costs that BPI currently pays

to the City for Daffron support. In addition, the new CIS system is expected to bring a number of benefits, which are difficult to quantify, such as:

- qualitative benefits outlined above,
- reduced development costs to meet regulatory/industry requirements
- reduced foreign exchange risk as current Daffron support charges are in US dollars
- productivity gains in the longer run

e) Below table provides a breakdown of the estimated annual support and hosting fees. The fees for hosting and support are high level budgetary estimates based on RFI responses received in early/mid 2015.

Expense	**Detail/basis for estimate**	**Annual Amount**
Annual enhancement fee	Annual fees charged by the software vendors to allow access to software updates, releases and upgrades. This fee is a percentage of the software license cost.	$ 50,463
Annual hosting charges	Annual charges for hosting the CIS application.	$ 50,000
Total		**$100,463**

IR: 4-SEC-21

[Ex.4-2-2, p.2]
For each new position created since 2014, please provide a full job description and justification for why the position is required.

Response:

See below for the full job descriptions for each position created since 2014.

Communications Specialist:

Justification: This position will manage the internal communications within BPI, ensuring that messaging related to both BPI and industry policies and new developments is are consistent and effective. The external aspects of this position will enhance communication with public stakeholders, and particularly with customers. The new role will also be responsible for the coordination of third-party communications service providers. BPI intends to leverage this position, together with its new Outage Management System in the future to enhance the communication with customers during an outage. Specifically, the role will be tasked with the design and management of BPI's social media presence.

Summary:

Reporting to the Vice President of Customer Service and Conservation, and working collaboratively with the leadership team, the Communications Specialist will provide expertise in the planning and implementation of Brantford Power's communications and outreach strategies, both at the conceptual and tactical levels. He/she will be responsible for using innovative communication tools, including web-based and social media platforms, to promote and expand the reach and impact of internal and external communications, and to ensure a consistent branding experience for all stakeholders. With frequent exposure to confidential and sensitive company and customer information, the incumbent will be expected to maintain confidentiality while performing all duties.

Responsibilities:

- Develop and maintain an annual communications strategy and outreach calendar, and devise tactics to execute activities in alignment with corporate priorities.
- Lead corporate website, billing portal and intranet development and maintenance from concept to final product.

- Support senior leadership with the timely research and development of briefing notes, press releases, media kits, FAQs and positioning statements.
- Create and deliver presentations, website and social media campaign copy, annual reports, publication and advertising copy, and letters.
- Conceptualize and produce visually appealing content, and logical internal and external communications.
- Create and maintain a Social Media Policy and Standard Operating Procedures.
- Coordinate customer-facing notices and messaging including bill messages, buck slips, inserts and special mailings.
- Plan, negotiate and execute logistics for corporate events, conferences and sponsorships.
- Perform quality control of all content by conducting substantive edits, copy editing and proofreading to ensure accuracy, consistency and tone of message.
- Implement and maintain a Crisis Communication Plan in support of emergency preparedness and business continuity.
- Support senior management with the public relations aspects of crisis management and business interruptions.
- Monitor and ensure a positive brand and social media presence.
- Prepare and analyze monthly Google Analytics reports for all corporate websites.
- Secure external resources to support communication activities as required, and manage third-party agreements and vendor relationships to ensure standards and quality are met.
- Support the promotion of conservation initiatives and outreach programs.
- Conduct industry research to better understand emerging trends and concepts.
- Prepare updates on the impact and effectiveness of communication strategies for senior leadership, including post-activity event evaluations and reports.

Senior Regulatory Analyst:

Justification:

New position required to provide additional support in lieu of filling Manager of Regulatory position.
Summary:

Reporting to the CFO & Vice President Corporate Services, the Senior Regulatory Analyst is responsible for providing analytical support to the regulatory activities of Brantford Power with respect to the requirements of the Ontario Energy Board and other regulatory agencies.

Responsibilities:

- Provide support to a wide-range of regulatory activities to ensure that Brantford Power operations are in compliance with all regulatory codes, bulletins and directives
- Play key role in achieving Brantford Power strategic goal to grow regulatory expertise and depth

- Provide training to regulatory staff and Brantford Power staff; liaise with staff and service providers to evaluate impact and develop implementation plans
- Develop and maintain systems to track data required for routine regulatory filings
- Manage schedule and data collection processes to ensure regulated timelines are met
- Research and develop methodologies to ensure compliance with regulatory codes
- Participate in periodic internal compliance reviews
- Undertake rate, operational, costing, and economic analyses, as appropriate, to support regulatory submissions
- Monitor and analyze ongoing changes to regulatory codes, discussion papers, and other related documentation reporting on potential impacts to Brantford Power's operations
- Participate in regulatory working groups and internal support teams
- Maintain and work through regulated consultation and process requirements to revise, in consultation with service providers and departmental staff, Brantford Power's Conditions of Service
- Analyze monthly service level billings and report on trends
- Maintain Retail Service Agreements to ensure that all data is accurate and up-to-date
- Other duties as assigned

Manager, System Projects and Business Applications

Justification: BPI required an internal resource dedicated to the coordination of the Systems Integration Projects.

Summary:

Reporting to CFO and Vice President of Corporate Services, the Manager, System Projects and Business Applications, is responsible for the design; implementation oversight and management of Brantford Power's IT function and the corporate-wide information technology projects through an entire project life cycle from inception through implementation. The Manager, Systems Projects and Business Applications is also responsible for maintaining, supporting, and upgrading existing systems and applications. This role applies proven leadership; project management, communication, and problem-solving skills, and knowledge of best practices to guide leadership and operational teams on issues related to the design, development, and deployment of information and software systems as they align with Brantford Power Inc.'s and Affiliate companies business strategies and objectives.

Manage and provide direction for the design and implementation of immediate and future IT functionality in support of business operations. Act as key advisor on general operation IT matters.

Responsibilities:

- Provide leadership, direction and project management to the business and its leadership team in the areas of system integration and implementation systems projects.
- Provide technical leadership for ongoing monitoring and operations management of IT environment.
- Provide technical leadership and management to project managers; subject matter experts; testers and programmers working on development project teams as required.
- Establish and manage strategies, guidelines, procedures, and standards to ensure effective ongoing support of Daffron, Brantford Power's billing and customer information system.
- Manage and support system implementation phase of key projects specifically, E-Billing, F.I.S. and C.I.S.
- Manage testing personnel and establish training; development; testing protocols; scripts and scenarios.
- Manage the relationship with the City of Brantford IT Department to ensure that application development projects meet both current and future business requirements and goals, and fulfill end-user requirement.
- Conduct research and make recommendations on software products and services in support of procurement and development efforts.
- Coordinate feasibility studies for software and system products under consideration for purchase, and give advice based on findings.
- Lead testing phase of development by evaluating proposals in order to identify potential problem areas, and make the appropriate recommendations.
- Manage the development, integration and deployment of new applications, systems software, and/or enhancements to existing applications throughout the enterprise.
- Manage relationships and project plan compliance with analysts, designers, vendors, and system owners in the testing of new software programs and applications

- Ensure that any new software integration into company systems meets functional requirements, system compliance, and interface specifications.
- Identify and resolve systems issues.
- Develop strategies for improving or leveraging existing applications.
- Review and analyze existing application effectiveness and efficiency.
- Design, develop, and install enhancements and upgrades to systems and application software.
- Develop, disseminate, implement and enforce functional policies, procedures, and quality assurance best practices.
- Prepare, establish, and monitor budgets where necessary.
- Maintain software version control by developing Change Management Software practices.
- Perform other duties as assigned.

Acting Supervisor of Settlement:

Justification: Required on a temporary basis while Supervisor of Settlement was deployed to focus on Systems Integration Projects, in order to keep compliance and levels of service continued.

Summary:

Reporting to the Supervisor, Settlement and Smart Metering, in addition to your daily Settlement, Energy and Smart Metering Officer responsibilities

Responsibilities:

- Approve invoices from service providers to Metering & Settlement Department over $6000.00 within approved signing authority.
- Create billable work orders in the customer information system (CIS) for special meter installations and authorize the charges related to the work order
- Coordinate with Acting Metering Coordinator department work required for the placement of interval meters at interval load and generator locations.
- Coordinate the daily work of the Settlement, Energy & Smart Metering Officer (SESMO) to ensure work is completed in compliance with all safety requirements
- Prioritize and oversee the work of the SESMO and Meter Technician(s) to resolve problems with the FlexNet system and smart meters
- Oversee the Notice of Disagreement (NOD) and the Dispute processes with the Independent Electricity System Operator when the daily statements are incorrect.

- Review the monthly Independent Electricity System Operator for remuneration for fixed pricing on behalf of BPI and Energy Market Retailers
- Review and approve data provided for surveys and regulatory filings to external agencies such as the Ontario Energy Board, Hydro One and Ontario Power Authority, Measurement Canada
- Responsible for the Department Profiler Portfolio for third party access for electric meters and requests for interval data on an annual basis to ensure Brantford Power is compliant with the Ontario's Freedom of Information and Protection of Privacy Act
- Participate and attend industry events as required;
- Approve SESMO time entry in BPI electronic time keeping system, vacation requests, planned and unplanned absences;
- HR responsibilities including SESMO annual Performance Appraisal and performance management;
- Duties as assigned

Cashier:

Justification: Required to ensure customer-facing service to BPI's customer base, many of whom prefer to make payments in person.

Summary:

Reporting to the Manager of Customer Service, the Cashier will process payments for Branford Power Inc. Duties will include but are not limited to processing counter payments, mail payments, receivables and issuing receipts; balancing cashier activity daily; running daily close and daily audit; balancing cashier general ledger summary; maintaining post-dated cheques and filing payment stubs.

Financial Analyst:

Summary:

Reporting to the Manager of Finance, the Financial Analyst will be responsible for the preparation of financial statements as well as general accounting functions as they relate to the Brantford Energy Group. The incumbent is responsible for verification of financial data to ensure accurate and timely information is available for reporting. Other duties in this position include but are not limited to preparing and entering journal entries in accordance with documentation received, account reconciliations, interacting with internal departments to resolve any accounting issues, payroll analysis, budget to actual variance analysis and reviewing account coding on accounts payable.

Conservation Program Coordinator

Justification: Required to fill additional duties associated with the new Conservation Framework , which has increase CDM savings targets compared to previous Frameworks.

Summary:

Reporting to the Conservation Program Manager, the Conservation Program Coordinator will assist with the coordination and administration of Brantford Power's conservation initiatives including:

- The accurate accumulation, input, tracking and analysis of conservation data from various sources for preparation of required reports, contracts, financial documents.
- Liaising with third party service providers, including, but not limited to, marketing consultants, customer outreach teams, graphic designers, equipment wholesalers, electricians and customer contractors, so as to meet mandated conservation requirements for various programs.
- Completion of facility site visits including assessments to identify conservation opportunities and completion of program qa/qc requirements.
- Assist with the development and delivery of marketing material, customer outreach activities, educational material, presentations and events, including representing Brantford Power at conservation and industry related events, functions and workshops.
- Perform administrative and general clerical duties such as record keeping, maintaining complete and accurate records on all conservation files, initiative tracking, and report preparation, proofreading and filing as required.

This role will work closely with the Conservation Program Advisor as well as program stakeholders including internal resources, customers, channel partners, and non-government organizations.

IR: 4-SEC-22

[Ex.4-4-2 p.7]
Is the Applicant recovering any of the costs for its Vice-President Customer Service and Conservation from amounts available from the IESO for CDM activities? If so, please provide details.

Response:

Please refer to the response to 1-EP-6 a). BPI recovers the amounts allocated to CDM associated with this position from the IESO through its approved budget form the IESO.

IR: 4-SEC-23

[Ex4-5-1, p.9]
Please explain why there is not a decrease in the Applicant's OM&A as a result of a reduction in services to be provided to BPI in 2017 as a result the City of Brantford forecasted sale of that asset.

Response:

BGI operations have been transferred to the City as of May 2, 2016 and BGI assets were sold on August 18, 2016. BGI as a legal entity with no operations will continue to exist until the company is legally dissolved. The City of Brantford through its SLA with BPI provides services for BPI only, which is separate from any services provided to any other affiliates in the Brantford Energy Corporation group of companies. BPI in turn, until the BGI is legally dissolved, will be providing executive and corporate services to BGI.

Services from the City of Brantford to BPI: There is no impact for the services provided by the City of Brantford to BPI since the Service Level agreement has not, and will not include any goods or services provided for BGI.

Services from BPI to BGI: BPI services provided to BGI (financial and executive services) will cease to be provided once BGI as a legal entity is dissolved. Until that time, the level of services will be reduced due to the fact that BGI no longer is an operating business following the transfer and subsequent sale of assets to the City.

There is no decrease associated with the sale of the asset. BPI finance and executive staff will cease to provide services to BGI when BGI as a legal entity is dissolved. As a result, the services billed to BGI will end, reducing the revenue offset for affiliate services provided for BGI. There will be no decrease in gross OM&A as the costs previously allocated to BGI are related to full time BPI employees. The time which would previously have been allocated to BGI will now be spent on BPI projects such as the SIP and facility relocation projects, as well as other ongoing work. The OM&A costs will be reallocated within BPI OM&A accordingly.

IR: 4.0 -VECC -30

Reference: Exhibit 4,

a) Please update the status of collective bargaining.

Response:

Both BPI and the IBEW have ratified a tentative agreement. BPI is in the final stages of completing an updated agreement with its IBEW workers. A draft agreement with the agreed upon changes has been compiled and is being reviewed by Management after which the union will review to confirm it represents correctly the tentative agreement.

IR: 4.0 -VECC -31

Reference: **Exhibit 2/T1/S1/pg.17,**

a) Please confirm the forecast savings from the consolidation of buildings is $574,902 per year (as per Table 2-1-H).

Response:

BPI is withdrawing the request for funding for its facility in the Bridge and Test Years. Please refer to the response to 2-Staff-7 for further information.

IR: 4.0 -VECC -32

Reference: Exhibit 4/T1/S1

a) Please confirm that there are incremental OM&A costs since the last cost of service filing of $495,143 due to the proposed new IT projects.
b) If this is confirmed please provide details of this ongoing cost specifically identifying the FTE related incremental costs.

Response:

a) The referred to table 4.1-B was a summary of BPI's Cost Drivers table. As indicated below in the response to 4-EP-35, the cost driver table was incorrect, the impact related to System Integration from 2016 to 2017 should have been reduced $(43,252) and therefore the corrected total for the System Integration Project Row in table 4.1-B should have been $451,891. However, this is not the total due to the proposed new IT projects, as the 2017 costs considered in this table are the normalized costs per table 4.2-F.

b) The ongoing costs are set out for each project in tables 4.2-C to 4.2-E there are no ongoing FTE related incremental ongoing costs. The 5-year period includes the temporary backfill positions and the Manager, System Projects and Business Applications

IR: 4.0-VECC-33

Reference: E4/T2/S1/Table 4.2-B:Cost Drivers/E4/T2/S1/pg.17/Appendix 2-JC

a) Please explain how the forecast for 2016 and 2017 for bad debt is derived.
b) Please explain the increase in collections OM&A costs in 2017 as compared to 2015 and prior.
c) Will the increase in collections costs lead to lower bad debts. If not please explain why not?

Response:

a) The bad debt expense for 2016/2017 was set at a level of $300,000 per year. This was based on the previous years' actual write-offs with a two year lag, which was approximately $300 000 each year. BPI notes that the bad debt expense in 2015 appears to be off-trend at $95 248 due to a one-time credit as a result of a one-time reduction in BPI's Allowance for Doubtful Accounts. This adjustment resulted from a review and update of BPI's method of estimating the annual allowance for doubtful accounts as suggested by BPI's external auditors.
b) The increase is related to an increased allocation to 5320- Collecting of compensation and payroll burden allocation. This is related to an employee who, for 2015, was performing work booked to Billing rather than Collections, but for part of 2016 and all of 2017 will be booked to Collecting. Additionally, there are changes related to the automated sending of field collection notices which account for a portion of the increases in this account.
c) BPI acknowledges that certain increases in collections costs may lead to lower bad debts. However, some increases do not. For example, part of the increase in collections cost between 2015 and 2017 is attributed to the cashier function. This function does not perform any special duties related to collecting on delinquent accounts. Some cost increases are expected to help reduce bad debts. Additionally, if customer behaviour changes (for example related to poor economic conditions), it may take more collection cost and effort to maintain the same level of bad debt.

IR: 4-VECC- 34

Reference: E4/T2/S1/Table 4.2-C

a) Please confirm that the $596,786 in OM&A costs are not recovered in the revenue requirement for 2017 or beyond.
b) Please provide a breakdown/details as to the nature of the 596k and $108k in FIS OM&A related implementation costs.
c) Please explain why FIS fees are paid to the City after implementation of the new FIS system.

Response:

a) Correct, 2016 OM&A was not part of the amortized SIP costs.

b) Below table provides a breakdown of the $596K in FIS OM&A implementation costs for 2016:

Expense	Detail/basis for estimate	Amount
External consultant fees for Implementation services (portion not relating to the design, build and testing of the system that needs to be expensed)	Implementation services quote received during the Best and Final Offer (BAFO) from the preferred vendor: $554,500 (for 2016) O&MA portion of the above quote : (50% of the above, based on our review of the fee breakdown, activities relating to design, build and testing, cost of which can be capitalized, were approximately 50% of the total effort; Remaining 50% were project management, training, and other such activities which cannot be capitalized and hence expensed here)	$277,250
External consultant out of pocket expenses	Out of pocket expenses estimate based on the BAFO quote of the preferred vendor	$18,000
Internal resources cost (portion not relating to design, build and testing of the system that needs to be expensed)	Internal resources effort was estimated using the BPI resource involvement expectations outlined in the RACI (Responsible, Accountable, Consulted and Informed) chart submitted as part of the BAFO by the preferred vendor. This effort was then multiplied by the average hourly rate	$202,071

	for BPI employees to arrive at the internal resources cost estimate: $301,599. BPI reviewed the RACI and estimates that approximately 33% the of these costs can be capitalized (being effort relating to design, build and testing) and the remainder (67%) is expensed here: $301,599 x 67% = $202,071	
Contingency	Since the above costs were based on the BAFO quote which was tentative and subject to change after a detailed planning (scoping or discovery) phase, BPI considered it prudent to provide for a contingency of 20% on the above costs as contingency. 20% of $497,321	$99,465
Total		**$596,786**

Below table provides a breakdown of the $108K in FIS OM&A implementation costs for 2017:

Expense	Detail/basis for estimate	Amount
External consultant fees for Implementation services (portion relating to training and post implementation support)	Implementation services quote received during the Best and Final Offer (BAFO) from the preferred vendor: $90,000 (for 2017) O&MA portion of the above quote : Entire portion of this cost is training and post implementation support and hence needs to be expensed (cannot be capitalized)	$90,000
Contingency	Since the above costs were based on the BAFO quote which was tentative and subject to change after a detailed planning (scoping or discovery) phase, BPI considered it prudent to provide for a contingency of 20% on the above costs as contingency. 20% of $90,000	$18,000
Total		**$108,000**

c) BPI response: BPI is not planning to migrate the detailed historical transaction data from the existing City FIS system to the new FIS system. In order to meet the regulatory and other requirements on retention of data, BPI has requested the City to allow BPI to maintain access to the historical information in the existing City FIS. Accordingly, the costs for FIS support have been retained at the same level year on year.

IR: 4-VECC-35

Reference: E4/T2/S1/Table 4.2-

a) Please explain why BPI appears to be paying a full year of fees for the current year and a partial year of fees for the new CIS system in 2017.

Response:

As per the Table 4.2-D CIS Implementation and O&MA costs, annual support fees paid to the City of Brantford for the current Daffron CIS is $636K in 2016 and $649K in 2017. Implementation cost of $746K is estimated based on the professional fees estimates received in response to the RFI for the FIS and CIS systems. As in the FIS system, the portion of the fees that relate to design, build and testing of the system are treated as capital (50%) and the remainder (50% of the fees) is treated as expense. This is based on our review of the approximate split between activities that can be capitalized (design, build and test) and others. $746K relates to the 50% that is expensed as OM&A. The annual support and hosting fees start in 2017 and subsequent years include external costs (annual support and hosting fees paid to software vendor and hosting provider) and internal costs (internal support for the new CIS system – on the lines of the current City of Brantford CIS system support).

IR: 4-VECC-36

Reference: E4/T2/S1/Table 4.2-F

a) Please identify any OM&A costs that are expected to be incurred prior to 2017 which are included in the normalization of Implementation costs as shown in Table 4.2-F (i.e. confirm the statement at page 15 which states no OM&A prior to 2017 is included).
b) What are the current 2016 related OM&A implementation costs.

Response:

a) There are no OM&A costs that are expected to be incurred prior to 2017 which are included in the normalization of implementation costs shown in Table 4.2-F. The statement on page 15 is correct when it states that no OM&A costs prior to 2017 are included.

b) The 2016 related OM&A implementation costs are $596,786.

IR: 4-VECC-37

Reference E4/T4/S2/pgs.23-

a) Please provide a table which lists each new incremental positon, starting from Board approved 2013 to 2017. In one column provide the salary band mid-point (not actual salary) and, separately, the average benefit cost for the incremental position. In another column provide the hiring start date (actual or forecast). In the final column provide a brief synopsis of the reason for the incremental positon.

b) Please confirm that the both the salary and benefits of the 3 conservation positions are not included in the OM&A figures or in the proposed revenue requirement (or confirm that there are equal offsetting revenues).

Response:

a)

New Position	Department	Year	Salary Mid Point	Average Benefit Cost	Hiring Date	Reason
VP Customer Service and Conservation	SLT	2014	$ 117,725.00	$ 22,892.59	May-14	Increase the focus on the customer
Financial Analyst	Finance	2014	$ 63,952.20	$ 22,892.59	Aug-14	Meet work load requirements with a permanent resource.
Acting Manager of Customer Service	Customer Service	2014/2017	$ 94,119.00	$ 22,892.59	Jun-14	Backfill during CIS project
Apprentice	Operations	2014	$ 38,055.68	$ 22,892.59	May-14	Fill two empty positions
Acting Manager of Finance	Finance	2014	$ 94,119.00	$ 22,892.59	Jun-13	Backfill during FIS project
Senior Regulatory Analyst	Regulatory	2015	$ 85,409.00	$ 22,892.59	Jan-15	In lieu of Mgr of Regulatory
Part Time Conservation Program Advisor	CDM	2016	$ 44,189.15	statutory benefits only	Jan-16	To assist with new CDM Framework
Communications Coordinator	Communications	2016	$ 38,673.18	statutory benefits only	Sep-16	Assist with internal and external communications; social media presence
Facility Manager	Facilities	2016	Mid Point Unknown	$ 22,892.59	deferred	Assist with project management related to facility relocation.
Manager of System Projects and Business Applications	BP- IT	2016	$ 96,725.00	$ 22,892.59	Q4 2015	Act as project manager for full Systems Integration Project.
Accounting/AP Clerk	Finance	2017	$ 51,790.05	$ 22,892.59	Forecast: 2016	Assist with the "in-housing" of Accounts Payable and Payroll.

*for CUPE positions the 1 year rate out of a 2 year scale has been indicated
*for exempt positions the job rate (100%) has been indicated from the 90% to 110% band
*for IBEW positions the rate indicated is the November rate of that year - adjustments provided in June & November
as there is not significant variance from one position to another, used 2017 average over all positions.
Mid Point for Non-salaried employees based on expected work hours

b) BPI confirms the 3 conservation positions are not included in OM&A, but in the Revenue Offsets accounts 4375 and 4380.

IR: 4.0-VECC-38

Reference: E4/T5/S1/Tables 4.5-A Appendix 2-N

a) Please explain the increase in affiliate IT services to 916k in 2016 as compared to prior years and notwithstanding the transfer of FIS and other systems to from the city to BPI.
b) In explaining the variance as between 2013 and 2017 BPI speaks of an IT employee joining and being part of the CIS project. Please clarify the role of City IT personnel in the transition to the new FIS and CIS systems and their role (if any) after implementation of these new systems.

Response:

a) As explained below Table 4.5-A Appendix 2-N, IT costs are projected to increase from 2015 Actual to the 2017 Test Year by $166,170. In 2015, there was one less Programmer Analyst than originally anticipated and included in the Shared Services Agreement with the City of Brantford. This City of Brantford employee is anticipated to return during 2016 and therefore BPI has budgeted the 2017 Test Year including this individual, especially due to the transition from the legacy CIS to the new CIS planned for 2017.

   BPI's IT services from the City of Brantford encompass installation and support of hardware, software and licenses, as well as support for all networks, e-mail and Internet services. FIS and CIS are only a portion of those services.

   For the FIS implementation, BPI is not planning to migrate the detailed historical transaction data from the existing City FIS system to the new FIS system. In order to meet the regulatory and other requirements on retention of data, BPI has requested the City to allow BPI to maintain access to the historical information in the existing City FIS. Accordingly, the costs for FIS support have been retained at the same level year on year.

   For the CIS procurement, implementation of the CIS is expected by end of 2017 and a reduction in the City of Brantford SLA charges (for CIS support) is reflected in Table 4.2-D: CIS Implementation and OM&A costs from the year 2018 (after the implementation is complete).

b) *City IT role beyond implementation of new systems:*

   City IT services under the current Service Level Agreement (SLA) with the City of Brantford include:

   - Installing and maintaining all hardware, software and licenses

- Providing support for all hardware, software and licenses
- Providing, maintaining and support all networks, e-mail and internet services; and
- Providing network security.
- Special projects from time to time including systems development and web development and maintenance as discussed and agreed upon

All the above City IT services are expected to continue beyond the implementation of the FIS and CIS systems with the exception of the FIS and CIS systems which will move to external software vendors and hosting providers. BPI will continue to use the City IT services for network, internet connectivity, e-mail, file servers, user laptops and network security. Also, the related hardware, software, licenses and support will continue to be provided by the City IT team.

On the FIS system, BPI plans to retain access to the City FIS system to access historical information and meet the regulatory and business needs for such historical information. On the CIS system, BPI will determine the right approach for support and maintenance of the new CIS through the selection and implementation process of the new CIS and assess if there is any continuing role that the City IT will play in the support of the new CIS.

City IT role in the transition to the new FIS and CIS:

City IT will play the below role in the transition to the new FIS and CIS. These services are included in the SLA with the City:

- City IT teams provide their technology expertise in advising BPI on the selection of the new FIS and CIS (solution, hosting, connectivity, security, etc.)
- City IT FIS and CIS teams will provide knowledge of the current systems and processes to help BPI and its implementation partner understand the current state of the systems and plan/design the transition to the new FIS and CIS
- City IT FIS and CIS teams will extract master data and historical transactional data required for migration to the new FIS and CIS systems
- City IT teams will also provide extracts/lists/data required to configure the new FIS and CIS systems
- City IT teams will develop or alter the interfaces to / from existing City systems to the new FIS and CIS

- City IT teams will setup/configure the required connectivity for the BPI employees to access third party hosting provider sites (data centres)

IR: 4.0-VECC-39

Reference: E4/T5/S1/Tables 4.5-A Appendix 2-N

a) Given the evidence that 2017 is a transition year for IT system implementation please provide BPI's forecast of shared service revenues and costs (i.e. Appendix 2-N) for 2018.

Response:

BPI understands the scope of this question to be relating to the services provided from the City of Brantford to BPI and therefore has only included the services between BPI and the City of Brantford. Please see the table below for BPI's forecast of the SLA services in 2018:

Year: 2018

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
City of Brantford	Brantford Power Inc.	Accounts Payable	Cost-based	$ -	$ -
City of Brantford	Brantford Power Inc.	Payroll	Cost-based	$ -	$ -
City of Brantford	Brantford Power Inc.	Purchasing	Cost-based	$ 20,000.00	$ 20,000.00
City of Brantford	Brantford Power Inc.	Human Resources	Cost-based	$ 66,905.00	$ 66,905.00
City of Brantford	Brantford Power Inc.	Information Technology	Cost-based	$ 471,774.00	$ 471,774.00
City of Brantford	Brantford Power Inc.	Legal and Real Estate	Cost-based	$ 12,190.00	$ 12,190.00
City of Brantford	Brantford Power Inc.	Mailrun	Market-based	$ 7,738.00	$ 7,738.00
City of Brantford	Brantford Power Inc.	Telephone Service	Cost-based	$ 16,661.00	$ 16,661.00
City of Brantford	Brantford Power Inc.	Insurance and Risk Management	Market-based [premiums], Cost-based [Administration]	$ 137,411.59	$ 137,411.59
City of Brantford	Brantford Power Inc.	Records Management	Market-based	$ 6,231.00	$ 6,231.00
City of Brantford	Brantford Power Inc.	Facility Asset Management	Cost-based	$ 107,148.00	$ 107,148.00
City of Brantford	Brantford Power Inc.	Rental of Facilities-Office Space	Market-based	$ 71,353.00	$ 71,353.00
City of Brantford	Brantford Power Inc.	Rental of Facilities-Office/Warehouse/Vehicle Storage	Market-based	$ 109,072.01	$ 109,072.01
City of Brantford	Brantford Power Inc.	Tree Trimming	Market-based [third-party services]; Cost-based [Administration]	$ 380,038.00	$ 380,038.23
Brantford Power Inc.	City of Brantford	Street Light Maintenance	Cost-based	$ 182,333.31	$ 182,333.31

IR: 4.0-VECC-40

Reference: E4/T5/S1/Tables 4.5-A Appendix 2-N

a) Please explain how street light maintenance is charged (e.g. on a per unit serviced or annual fixed sum basis).
b) If it is charged on a per unit basis please provide a table showing the units serviced, fee and total (i.e. sum shown in Appendix 2-N).

Response:

a) Street light maintenance is charged on a time and material basis. Time and materials are charged by the linesman as they do street light maintenance.
b) Not applicable as street light maintenance is not charged on a per unit basis. Different units may have different time and materials requirements, and therefore the time and materials will vary from unit to unit.

IR: 4.0 -VECC -41

Reference: Exhibit 4, Attachment 4-H, pages 12-13
Exhibit 4, Attachment 4-J, Tables 1 and 2

a) With respect to the Residential CDM program savings used in Attachment 4-H, please explain why:
   i. The total Residential savings used for results from 2011 programs in 2013 (1,096,631 kWh) exceeds the reported savings in 2011 from 2011 programs (1,096,007 kWh – after adjustments to the verified results per Attachment 4-J) as one would have expected the value to be either equal or less due to loss of persistence.
   ii. The total Residential savings for the results from 2013 programs in 2013 (868,401 kWh) and in 2014 (867,452 kWh) both exceed the reported savings in 2013 from 2013 programs (853,969 kWh – after adjustment to verified results per Attachment 4-J).

Response:

BPI confirms the initial application incorrectly reflected the adjustments to verified results. Please refer to 3-VECC-23 and 3-VECC-22 and in particular attachment 3-VECC-22 which is an updated report from Burman Energy Consultants.

Exhibit 5: Cost of Capital

IR: 5-Energy Probe-50

Ref: Exhibit 5, Tab 1, Schedule 1 &

Exhibit 5, Tab 2, Schedule 1

a) Has BPI entered into a loan agreement with Ontario Infrastructure & Lands Corporation for the loan of $13.8 million shown having a start date of October 1, 2016 for a term of 30 years? If no, does BPI still expect to enter into such an agreement in 2016?

b) What is the current 30 year rate available from Infrastructure Ontario for such a loan?

Response:

a) No, BPI has not entered into a loan agreement with Ontario Infrastructure and Lands Corporation (OILC). No, BPI does not expect to enter such an agreement in 2016.

b) The current 30 year rate available from OILC is 3.22% as per their website, as of 09/09/2016

IR: 5-Energy Probe-51

Ref: **Exhibit 5, Attachment 5-A**

a) How was the rate of 4.20% determined for the renewal for 5 years of the affiliate debt?

b) Did BPI approach third party lenders to refinance all or part of the affiliate debt that came due in early 2016? If not, please explain why not? If yes, please provide a summary of the quotes received including amount, rate and term available from these parties.

Response:

a) The five-year renewal rate of 4.20% is stipulated in the promissory note at the Royal Bank of Canada's Prime Rate + 1.5%

b) BPI did not seek any debt from third parties in the same time frame for the following reasons. The existing City of Brantford promissory note is currently subordinated to both the Royal Bank and Infrastructure Ontario Long Term Debt. The introduction of a third lender at this time would have required a renegotiation of the relative security position of existing lenders. With the pending new financing required to fund the planned acquisition of consolidated facilities, BPI believed it was prudent to continue to retain the City of Brantford's promissory note because its current subordinated position provides BPI with the most flexibility to secure new financing for the facility acquisition. BPI reviewed the stipulated five year renewal rate contained in the promissory note at Prime + 1.5% against the OEB's deemed long term debt rate and the publicly available 30 year rate available from Infrastructure Ontario in December 2015.

   Infrastructure Ontario had advised Brantford Power Inc. that it would not be eligible for any new financing until such time Infrastructure Ontario and Brantford Generation Inc. (affiliate of Brantford Power Inc.) had resolved their issues. Consequently, this lower rate was not available to Brantford Power Inc. at the time of renewal.

Illustration of Alternative Financing Rates

Source	Current Rate
Promissory Note Renewal Rate (Prime + 1.5%)	4.20%
Ontario Energy Board Deemed Long Term Debt Rate	4.54%
Infrastructure Ontario Long Term Debt Rate (30 year Term – Dec 3)	3.89%

Consequently, BPI proceeded with the 4.20% as the lowest cost alternative.

IR: 5-SEC-24

[Ex.5]
Please provide the Applicant's regulated ROE for each year since 2013.

Response:

The following chart shows BPI's regulated ROE for each year since 2013.

Year	Achieved ROE	
	As reported	As Adjusted**
2013	11.60%	
2014	11.15%	9.98%
2015	11.06%	8.97%

**Please note that 2014 and 2015 have been adjusted to reflect a situation related to loss carry forwards which resulted in BPI reporting overstated ROEs for both years. Please refer to 4-EP-44 for full details.

IR: 5-SEC-25

[Ex.5-Attach. 5A]
Please provide a copy of the previous Promissory Note with the City of Brantford.

Response:

Please see attachment 5-sec-25

IR: 5-SEC-26

[Ex.5-Attach. 5A]
Before renewing the Promissory Note with the City of Brantford, did the Applicant look at replacing that debt from a third-party provider? If so, please explain why it chose not to.

Response:

Please refer to BPI's answer in 1-Energy Probe-1.

IR: 5.0-VECC-42

Reference: E1/T8/S1

a) Please provide a table showing the achieved ROE for 2011 through 2016 with an additional row showing the Board ROE approved for 2011 and the subsequent ROE benchmarks set by the Board each year 2012 through 2015.

Response:

The following table shows BPI's achieved ROE for 2011 through 2015 as well as the Board approved ROE for each year.

Year	Achieved ROE		Board Approved/Set ROE
	As reported	As Adjusted**	
2011	7.50%		8.57%
2012	3.20%		8.57%
2013	11.60%		8.98%
2014	11.15%	9.98%	8.98%
2015	11.06%	8.97%	8.98%

**Please note that 2014 and 2015 have been adjusted to reflect a situation related to loss carry forwards which resulted in BPI reporting overstated ROEs for both years. Please refer to 4-EP-44 for full details.

IR: 5.0-VECC-43

Reference: E5/Attachment 5-A

a) Is the new debt note with the City callable on demand?
b) Please explain what the "adjustment provisions of the Transfer By-law" are with respect to this note.
c) How was the rate of 4.20% determined for this note?

Response:

a) This is not a new debt note; rather the note's interest rate was just renewed. The note is not callable on demand.
b) On October 23, 2000 the City of Brantford passed By-law 156-2000 to transfer the assets, liabilities, rights and obligations of the Brantford Hydro Electric Commission and of the corporation of the City of Brantford in respect to the distribution and retailing of electricity to a corporation and its subsidiary of corporations incorporated under the Business Corporation Act (Ontario) pursuant to Section 142 of the Electricity Act, 1998. The adjustment provision was created so that adjustments to the consideration received by the City on the effective date of the transfer could be adjusted if the audited net book value of the assets was different from the fair market value of the assets which was used for initial determination of the value of assets. This was a common provision in Muncipal Transfer By-Laws as the valuation of assets transferred was typically assessed after the date of transfer. Consequently, a provision for a subsequent adjustment was required. This provision was related to the implementation of the Transfer By-Law and has not current relevancy.
c) The five-year renewal rate of 4.20% is stipulated in the promissory note at the Royal Bank of Canada's Prime Rate + 1.5%.

IR: 5.0-VECC-44

Reference: E5/T2/S1

a) Please provide the source of the 3.68% forecast for Ontario Infrastructure and Lands Corporation sourced debt.

Response:

BPI attained this rate from the OILC website under "Lending Rates: Local Distribution Companies" for a 30-year term loan. Refer to Attachment 5-VECC-44 for a screenshot of the website used at the time the Cost of Service Application was submitted. As no actual financing had yet been obtained, BPI used this rate as its assumed financing rate under the assumption that BPI would obtain the financing from OILC. BPI is not anticipating securing this financing in 2016.

Exhibit 6: Revenue Deficiency

IR: 6-Energy Probe-52

Ref: Exhibit 6

Based on any corrections, changes or updates, please provide updated live Excel work forms for the RRWF, PILS, Chapter 2 appendices, cost allocation model and any other work forms that have been changed as a result of the changes or updates. Please include the necessary entries in the Tracking Form in the RRWF indicating the interrogatory response which is the basis for the change made.

Response:

Please see the response to 1-staff-1b).

Exhibit 7: Cost Allocation

IR:7-Staff-61

Ref: Exhibit 7, Tab 1, Schedule 2 and Attachment 7-C

Brantford Power notes that its previous rates were designed without factoring in the expected transformer allowance credit. As a consequence, the Embedded Distributor rates have increased to address this shortfall.

a) Please confirm that Brantford Power is not proposing to recover the past shortfall.
b) OEB staff notes that the communication with Energy+ included in Attachment 7-Cdoes not appear to specifically address this increase. Was Energy+ made aware of this situation?
c) Energy+ indicates in its response to Brantford Power's communication that it would prefer a direct allocation methodology, although it accepts the current methodology for this application. Please calculate the total cost that would be allocated to Energy+ under a direct allocation methodology.

Response:

a) BPI confirms it is not proposing to recover the past shortfall.
b) BPI agrees the communication with Energy+ included in Attachment 7-C does not specifically address this increase, however, the issue was discussed with Energy+ as is indicated in the e-mail reply from the Chief Financial Officer on page 5 of Tab 1, Schedule2 in Exhibit 7:

    "Further to our discussions, …, including the transformer allowance issue."

c) BPI is not able to calculate the costs allocated to Energy+ under a direct allocation methodology as there are no assets that are specifically allocated to Energy+.

IR: 7-Energy Probe-53

Ref: Cost Allocation Model, Sheet I7.1

Please explain the difference between a smart meter and a smart meter – network and explain why 1,302 residential customers have the smart meter – network.

Response:

Smart Meter refers to a smart meter used on a 1.5 element electrical service (120/240 volts).

Smart Meter – Network refers to a smart meter used on a 2.0 element electrical service (120/208 volts).

The 1,302 residential customers are in buildings that have an internal, secondary distribution system configured 120/208 volts.

IR: 7.0 – VECC –45

Reference: E7/T1/S2, page 7

a) What, if any, adjustments have been made to Brantford's Standby rate since the approval of the 2013 Rates?
b) What are the forecast 2017 revenues from Standby Rates?

Response:

a) There have been no changes to BPI's Standby rate since the approval of the 2013 rates.
b) BPI has not included any revenue in 2017 from Standby rates. BPI no longer has any standby customers.

Exhibit 8: Rate Design

IR: 8.0 –VECC - 46

Reference: E8/T1/S1, page 5 (lines 9-13)

a) Have there been any updates to the load forecasts for either Embedded Distributor or the GS 50-4,999 classes?

Response:

BPI has not made updates to its forecasts prior to the responses to these interrogatories.

The section of Exhibit 8 referred to above relates to the update of transformer allowance forecasts given an update to the load forecasts in these customer classes. As part of its response to 1-Staff-1, BPI has updated its Load forecast. Accordingly the new Transformer Allowance forecasts for each class are outlined below:

Customer Class	Updated Transformer kW	Updated Transformer Allowance ($)
General Service greater than 50 kW	617,063	($370,238)
Embedded Distributor	139,437	($83,662)

Exhibit 9: Deferral and Variance Accounts

IR: 9-Staff-62

Ref: Exhibit 9, Tab 1, Schedule 1, Pages 3, 4

Brantford Power is requesting an accounting order to establish a new deferral account to capture any material variances in capital or OM&A resulting from the introduction of the Cap and Trade Program.

a) Per the Filing Requirements, in the event an applicant seeks an accounting order to establish a new deferral/variance account, the eligibility criteria of causation, materiality and prudence must be met. Please discuss how the requested account meets the eligibility criteria.
b) Please explain how Brantford Power is planning to distinguish cost variances solely attributable to the cap and trade program (as compared to other cost pressures that may arise from year to year).

Response:

a) Please find below BPI's discussion of how the requested new deferral account meets the eligibility criteria:

Criteria 1 - Causation – The forecasted expense must be clearly outside of the base upon which rates were derived.

Since the Government of Ontario's Climate Change Action Plan was introduced with the 2016 Budget and the Climate Change Mitigation and Low-Carbon Economy Act was passed on May 18, 2016 by the Ontario Legislature, it is not yet possible to determine or estimate the cost implications of the Government's new Cap and Trade program on BPI's operating or capital costs. Consequently, BPI has not included any provision or estimate of costs associated with this new Cap and Trade regime in its revenue requirement. As a result, none of these costs have been included in the base on which the proposed rates were derived.

Criteria 2 - Materiality – The forecasted amounts must exceed the OEB-defined materiality threshold and have a significant influence on the operation of the distributor, otherwise they must be expensed in the normal course and addressed through organizational productivity improvements;

As outlined in the first criteria, it is not possible to determine the materiality of the costs related to the cap and trade program as the program is targeted to be implemented on January 1, 2017. BPI understands that work continues on the regulations and it will be some time after the start of the program for an actual market price for offset credits to be established. Nevertheless, the Government has estimated that across the economy, the cap and trade program is expected to generate $1.8 to $1.9 billion per year in funding. Until the program is launched, Brantford will not be able to determine what its portion of this overall impact will be and whether it is material.

Because BPI is unable to confirm at this time whether the impact meets the materiality threshold, the application indicated that the proposed deferral account would only apply if the impact of this program met the materiality threshold once the impacts are known.

Criteria 3 - Prudence – The nature of the costs and forecasted quantum must be reasonably incurred although the final determination of prudence will be made at the time of disposition. In terms of the quantum, this means that the applicant must provide evidence demonstrating as to why the option selected represents a cost-effective option (not necessarily least initial cost).

Given the costs to be incurred related to the cap and trade program are the direct result of the Government of Ontario's Climate Change Action Plan, BPI submits that these impacts are essentially outside of BPI's control and cannot be avoided. Provided BPI continues with appropriate procurement processes that ensure prudent purchases are made, BPI believes that any material variances attributable to cap and trade can be shown to be prudent in the circumstances.

In addition to the above assessment of the three eligibility criteria, BPI believes there is precedent for creating a deferral account in cases where all three criteria may not be met when the costs impacts are the direct result of changes in Government policy as illustrated in the examples below:

1555/1556 Capital and OM&A smart meter variance accounts

These accounts were established in advance for a subsequent prudency review for the costs related to implement the Government's smart meter program.

1592 PILS and Tax Variances

This account was established to capture change in PILS rates when they deviate from those used in the determination of rates. In addition, a sub account was created to capture the impact of the Government of Ontario's decision to proceed with the harmonization of GST and PST into a single harmonized HST.

BPI believes that cost implications of the Government of Ontario's cap and trade program are consistent in nature with the above examples and should be given similar treatment with a deferral account to track the impacts pending a future prudency review.

b) BPI has not yet determined exactly how it will capture the incremental costs it is still unclear how the cost adjustments related to the cap and trade program will filter into the cost of goods and services. BPI would expect the following approaches could be used to determine the impact of the cap and trade program on LDC costs:

As BPI expects vendors will be assessing cap and trade impacts on their product and service pricing, BPI can use vendor evidence to support the incremental per unit impact on input prices;

As this change will likely be monitored and studied externally, BPI could use publicly available information on specific items to estimate the impact of cap and trade program e.g. – Government estimates, Statistics Canada reporting etc. For example, public reports have indicated that fuel prices are likely to be increased 3-4 cents per litre;

An estimate of the impact could be determined by analyzing the per unit pricing changes and removing a deemed regular inflation factor to isolate as a proxy the regular inflation component to remove the impact of other factors and solve for the remainder attributable to carbon pricing.

The reality is that LDCs will need to provide the same evidence whether supporting the disposition of the requested deferral account or in any future cost of service proceeding where such costs would be embedded in the updated cost of service. As these costs are expected to impact all LDCs, the OEB can also consider benchmarking the impacts to industry norms. In the end, it is up to the LDC to submit sufficient and appropriate evidence with its request for the disposition of the account.

IR: 9-Staff-63

Ref: Exhibit 9, Tab 1, Schedule 1, Page 19
Ref: Exhibit 1, Attachment 1-E, 2015 Audited Financial Statements
Ref: Exhibit 1, Attachment 1-F

Table 9.1E shows energy sales and cost of power of $107.3M. Energy sales are $110M and cost of power is $108.6M in Brantford Power's 2015 audited financial statements. In Brantford Power's RRR filing of the trial balance mapping to audited financial statements, Brantford Power shows a $3.3M adjustment to energy sales and a $1.36M adjustment to cost of power to reclassify RSVAs to a separate line item pertaining to movement in regulatory balances.

a) Please explain the components within the reclassification amounts and how the amounts are derived.
b) Please explain how this ensures that Brantford Power is not making a profit or loss on energy.

Response:

a) The components of the reclassification amount detailed in the chart below relate to the differences between amounts consumed by customers (billed and unbilled) and amounts paid to the IESO and embedded generators. These balances are accordance with *Article 490* of the *Accounting Procedures Handbook*.

Reclass of RSVA Adjustments - Sales of Energy to Regulatory Movement			
Charges - Power	- offset to 1588	$	1,546,523
Charges - WMS	- offset to 1580	$	1,778,497
Charges - CN	- offset to 1586	$	(30,328)
		$	3,294,692
Reclass of RSVA Adjustments - Cost of Power Purchased to Regulatory Movement			
Charges - Global Adj	- offset to 1589	$	(1,613,939)
Charges - NW	- offset to 1584	$	249,135
Charges - SME	- offset to 1551	$	4,783
		$	(1,360,021)

b) The chart below shows the various components of the Audited Financial Statements (AFS). The RSVA adjustments required to track regulatory assets and liabilities have been reported in the Regulatory Movement amount on the AFS ensuring there is no profit or loss reported on energy.

Audited Financial Statement			
Sale of Energy	$	110,089,757	
Reclass RSVA Adjustment mapped to Regulatory Movement	$	(3,294,692)	x
Reclass DVA Disp for Group 1 Accounts from Distribution Revenue	$	481,334	
Sales of Electricity per OEB RRR 2.1.7	$	107,276,399	
Cost of Power Purchased	$	(108,636,420)	
Reclass RSVA Adjustment mapped to Regulatory Movement	$	1,360,021	x
Power Supply Expenses per OEB RRR 2.1.7	$	(107,276,399)	
Net of Sale of Energy and Cost of Power Balances	$	-	
Total Regulatory Movement			
RSVA Adjustments from Sales of Energy above	$	(3,294,692)	x
RSVA Adjustments from Cost of Power above	$	1,360,021	x
DVA Dispositions for Group 2 Accounts	$	(266,501)	
Interest Revenue and Expense on DVA Accounts	$	37,744	
RCVA Adjustments	$	27,545	
Early Disposals of PP&E	$	93,246	
Tax on Regulatory Balances	$	894,460	
	$	(1,148,177)	

IR: 9-Staff-64

Ref: Exhibit 9, Tab 1, Schedule 1, Pages 4-15

With regards to the proposed disposition of Account 1582 RSVA One Time:

a) Please confirm that the adjustment relates to 2002 to 2005 balances.
b) Please confirm that the 2005 account balance excluding the adjustment was disposed on a final basis in the 2006 EDR.
c) Please explain why Brantford Power did not disclose the adjustment to the OEB during the 2006 EDR proceeding as it appeared that Brantford Power knew of the adjustment during the 2006 EDR proceeding.
d) Please confirm that the corresponding reallocation adjustment has been included in Account 1580 and was disposed. Please indicate when the adjustment was disposed.

Response:

a) Brantford confirms that the adjustment relates to 2002 to 2005 RSVA one-time items.
b) With respect to 1582 – RSVA – WMS – there were no outstanding balances at the end of 2004 prior to the correcting adjustment being posted in 2005. To the extent that the 1582 account had a NIL balance at the end of 2004, there was nothing requiring disposition. Nevertheless, as the application intended to dispose of all eligible 2004 DVA balances, to the extent this account was in that group, it would have been disposed on a final basis.

c) Brantford indicated in its 2017 Cost of Service Application the following:

"The adjustment was made in good faith as BPI internal accounting compliance review had identified the one-time items had not been correctly segregated into the 1582 One Time Item Variance Account as prescribed. As the focus at this time was accounting compliance performed by new staff to the Company, the connection to the already submitted disposition request was not made."

At that time, Brantford's regulatory and accounting functions were under separate organizational units reporting to separate executives. This structure resulted in limited interactions between the groups. Although the regulatory staff was aware that 2004 RSVA balances had been submitted for disposition as part of the 2006 EDR proceeding, the new staff in Finance did not appreciate that the adjustment of accounting anomalies prior to 2005 would have an unintended impact when Brantford would apply the 2006 EDR disposition decision to the post adjusted RSVA balances.

It was not until the outcome of the 2013 Cost of Service Decision that Brantford identified an issue existed with this 1582 - RSVA - one time account and it was not until the 2015 IRM application that feedback from OEB staff regarding the 2004 approved disposition that Brantford determined further investigation was deemed necessary.

As a result, Brantford conducted a full review of the 1582 and 1580 accounts to re-create the sequence of events leading to the 2015 RSVA balances. This review confirmed that this issue was directly related to the incorrect adjustment of the RSVA – One Time 1582 account posted in 2005. That is why; Brantford is requesting that the entry be reversed with the result that all variance accounts return to their respective correct balances.

In summary, although there was some staff in the Company that understood that 2004 balances were being disposed of in the 2006 EDR proceeding, the implications of the separate accounting group making prior year accounting corrections to balances that had already been submitted for disposition on a pre-adjusted basis was not identified by any one at Brantford. Consequently, Brantford was unaware at that time that an anomaly existed between the 1580 RSVA-WMS and the 1582 RSVA – one time variance accounts.

d) Yes, the credit adjustment made to adjust 1582 RSVA One Time reduced the amount to be recovered in 1580 RSVA – WMS. Since the 2006 EDR rate decision authorized the originally requested amount based on the pre-adjusted 1580 RSVA – WMS balance, the disposition recorded in 2007 related to 2006 EDR resulted in an understated 1580 RSVA – WMS balance equal to the value in 1582 RSVA One Time that has been carried since that time. The understated 1580 RSVA – WMS balance was next disposed of in 2010 IRM.

IR: 9-Staff-65

Ref: DVA Continuity Schedule

In the DVA continuity schedule, Account 1508 Other Regulatory Assets – Sub-account Other, $173.6k is requested for disposition. From Brantford Power's 2013 cost of service application, the account appears to be for the difference between the existing approved GS>50 kW 2008 rates and a new rates determined in the EB-2009-0063 proceeding as a result of establishing an embedded distributor rate class. The account was disposed in Brantford Power's 2013 cost of service application. It appears that the account was to capture the difference in the rates from the 2008 rate proceeding to Brantford Power's next rebasing application in 2013.

a) Please explain why further amounts were added to the account after the disposition in Brantford Power's 2013 cost of service application.
b) Please explain why this account is to be continued going forward.

Response:

a) The amounts included in 1508 Other Regulatory Assets – Sub-Account Other represent the billing differences resulting from EB-2009-0063 from January 1, 2013 to February 28, 2014. BPI's 2013 cost of service application disposed of DVA balances to December 31, 2012. As the 2013 COS rates were not effective until March 1, 2014, rate differentials continued until this time.

b) This account should not be required for rate differentials related to EB-2009-0063 going forward. It is possible that it may be required for other uses in the future.

IR: 9-Staff-66

Ref: Exhibit 9, Tab 1, Schedule 1, page 17

Ref: DVA Continuity Schedule

Brantford Power is requesting disposition of Account 1592 PILS and Tax Variance for 2006 and Subsequent Years – Sub-account HST/OVAT ITCs for $37.5k. Brantford Power had already disposed of this account in its 2013 cost of service proceeding as per its settlement agreement DVA continuity schedule. Any impacts arising from the establishment of the HST were to be reflected in base rates going forward. Therefore, no amounts should be recorded after the disposal of this account.

a) Please explain why Brantford Power has recorded amounts in this account following the account's disposition.
b) If Brantford Power agrees that no amounts should have been recorded, please remove the requested disposition from the DVA continuity schedule and the associated rate riders.

Response:

a) The amounts included in 1592 PILS and Tax Variance – Sub-Account HST ITC's represent the PST portion of expenditures that were previously included in distribution rates from January 1, 2013 to February 28, 2014. BPI's 2013 cost of service application disposed of DVA balances to December 31, 2012. As the 2013 COS rates were not effective until March 1, 2014, HST variances continued until this time.

b) Brantford Power believes these amounts should have been recorded and should remain in the DVA continuity schedule.

IR: 9-Staff-67

Ref: DVA Continuity Schedule

Brantford Power's proposed account 1589 Global Adjustment disposition rate riders to be calculated based on kWh or kW depending on the class. Please revise the Global Adjustment rate riders to kWhs for all classes as per the Filing Requirements for 2017 Rate Applications. If Brantford Power wishes to continue with its initial proposal, please explain why.

Response:

The following table has been updated to reflect a disposition rate rider for account 1589 – Global Adjustment based on kWhs rather than the specific billing determinant for the customer class.

Rate Class	2017 Predicted kWh	2017 Predicted kW	Allocated Balance	Unit for Disposition	Rate Rider
Residential	20,001,558	-	$ 63,108	kWh	$ 0.0032
GS<50 KW	13,877,434	-	$ 43,786	kWh	$ 0.0032
GS>50 KW	422,125,863	1,155,881	$ 1,331,881	kWh	$ 0.0032
Street Light	7,460,329	22,796	$ 23,539	kWh	$ 0.0032
Sentinal Lighting	67,475	208	$ 213	kWh	$ 0.0032
Unmetered Scatter Load	-	-	$ -	kWh	$ -
Embedded Distributor	-	139,437	$ -	kWh	$ -
Total	**463,532,659**	**1,318,324**	**1,462,526**		

IR: 9-Staff-68

Ref: DVA Continuity Schedule
Ref: Exhibit 9, List of Attachments, Page 2

Due to the timing of the OEB's updated DVA continuity schedule, Brantford Power's schedule does not show Account 1580, sub-accounts CBR for Class A and Class B.

a) Please update the DVA continuity schedule to show the two sub-accounts, separate from the main control Account 1580 WMS (i.e. the control account is not to include any CBR related amounts)

b) Please request disposition of the CBR sub-account for Class B in accordance with the Accounting Guidance issued for CBR, dated July 25, 2016. Please update the rate rider calculations.

c) Brantford Power had 3 Class A customers in 2015. However, in the RRR 2.1.7 trial balance filed with the OEB, Brantford Power shows $0 for Account 1580, sub-account CBR for Class A. Please explain why there is a $0 balance in the sub-account.

Response:

a) BPI has updated the DVA continuity schedule to show the two sub-accounts, separate from the main control Account 1580 WMS (i.e. the control account does not include any CBR related amounts). The updated file is included as Attachment 9-Staff-68. Please note account 1551 is not fully allocated on Tab 5 and therefore, $347 is missing from the rate rider calculations on Tab 6. The table below sets out the actual rate riders being requested for the deferral/variance account balances (excluding Global Adj).

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Balance (excluding 1589)	Rate Rider for Deferral/Variance Accounts	
RESIDENTIAL	kWh	291,567,897	(84,364)	(0.0003)	$/kWh
GS<50 KW	kWh	99,837,652	(27,711)	(0.0003)	$/kWh
GS>50 KW	kW	1,241,682	(132,714)	(0.1069)	$/kW
STREET LIGHT	kW	22,796	(2,045)	(0.0897)	$/kW
SENTINEL LIGHTING	kW	1,181	(105)	(0.0887)	$/kW
UNMETERED SCATTER LOAD	kWh	1,405,154	(385)	(0.0003)	$/kWh
EMBEDDED DISTRIBUTOR	kW	139,437	(13,982)	(0.1003)	$/kW
Total			**(261,306)**		

b) BPI is requesting disposition of the CBR sub-account for Class B in accordance with the Accounting Guidance issued for CBR, dated July 25, 2016. BPI confirms:

1. The balance in account 1580 for Class B customers is a positive amount.
2. BPI does have Class A customers therefore the amounts related to Class B customers have been separated into sub accounts for principle and interest.

3. The rate riders calculated are more than 4 decimal points
4. A volumetric rate rider is appropriate and the amounts in the sub accounts referred to in 2 above have been included in the rate rider calculation in tab 6.

c) BPI did not have a Class A sub account for 2015 because the Class A customers are billed based on BPI's payments to the IESO and the amounts were previously included in the control account 1580. The DVA continuity schedule now separates the Class A amounts into separate sub-accounts for principle and interest and BPI will use and report against these accounts going forward. BPI has made adjustments to these accounts following the updated accounting guidance from OEB Staff in 2016.

IR: 9-Energy Probe-54

Ref: Exhibit 9, Tab 1, Schedule 1

More information is now available about the Ontario cap and trade program than when BPI filed its application. Does BPI still believe it requires the requested deferral account? If yes, please explain fully why and provide examples of what costs BPI expects would be included in it.

Response:

Although more information has been made available with respect to the Cap and Trade Program, there is not yet clear information how the introduction of carbon pricing will impact the cost of BPI's goods and services and since no provisions have been made in BPI's Test Year 2017 Cost of Service, the deferral account is still required.

As the purpose of the Cap and Trade program is to ensure that the underlying cost of carbon is reflected in the costs of all goods, it is reasonable to expect that the introduction of this initiative will impact BPI's ongoing Cost of Service beginning in 2017. As the Ontario Budget estimates that the annual revenues the Province will collect under this program could amount to $1.9 Billion annually, BPI is concerned that the introduction of this new Cap and Trade program will result in unrecovered Cost of Service beginning in 2017.

As Cap and Trade costs will result in new, previously non-existent, input costs to the manufacturing of equipment, goods and materials purchased by BPI, it is reasonable to expect that suppliers will adjust their pricing to recover these new additional carbon costs. At this time, there is insufficient information available to allow BPI to predict or forecast the impact of the Cap and Trade program in its proposed Cost of Service. It is expected that the nature of this program will be sufficiently broad that it will impact both capital costs and OM&A. Examples of costs that BPI expects are likely to be impacted by Cap and Trade costs are the following:

- Fuel used in the operations of the fleet and to heat facilities;
- The cost of significant manufactured goods e.g. transformers, fleet vehicles other materials used in the distribution system that is manufactured and transported;
- Increases in fees and charges by other government agencies and service providers who must pass on their cap and trade impacts to their respective customers or clients.

Eventually, those costs impact should filter through inflation measurements and impact future IPI factors used in the determination of annual IRM rate adjustments. A the present time the current IRM IPI methodology is likely to capture the timing and quantum of any cost impacts of the proposed Cap and Trade program for the industry however because of the requirement to use data which is readily available from public and objective sources, the indices are delayed to allow for appropriate analysis of the historical trending.

For example, the 2016, GDP-IPI (FDD) change was based on the actual data from 2013 and 2014. With the introduction of the proposed Cap and Trade program in 2017, assuming the same data analysis pattern with adds a new cost element to the mix, the earliest these measures could reflect the impact of the proposed Cap and Trade program will be for use in 2019 IRM rate adjustments. As BPI has not provided any provisions in its 2017 Cost of Service for Cap and Trade, without a deferral account, BPI would be required to absorb material 2017 and 2018 impacts of Cap and Trade should they occur as the IPI factor as currently structured would not have reflected any adjustment for this purpose.

Furthermore, until the Cap and Trade impacts are determined, it is unclear at this time whether the current weighting factors in the determination of the annual IPI factor will continue to be appropriate given the introduction of new costs inputs relating to carbon pricing could require an update to the 70/30 weighting percentages. It is likely reasonable to assume that the impact of carbon pricing will impact the labour and non labour components in a different proportion than the existing cost elements that resulted in the establishment of the 70/30 split.

Consequently, the approval of the deferral account will allow BPI to mitigate the risk of material cost impacts that have not been factored into its Cost of Service. The nature and quantum of any amounts recorded in the deferral account will be subject to a future prudency review including the methodology BPI will use to isolate these impacts. The account will not be used should the annual impact actual be below materiality threshold.

IR: 9-SEC-27

[Ex.9-1-1, p.3-5] Please explain what type of expenses the Applicant believe it may be required to incur as a result of Ontario's Cap and Trade program.

Response:

Although more information has been made available with respect to the Cap and Trade Program, there is not yet clear information how the introduction of carbon pricing will impact the cost of BPI's goods and services.

As the purpose of the Cap and Trade program is to ensure that the underlying cost of carbon is reflected in the costs of all goods, it is reasonable to expect that the introduction of this initiative will impact BPI's ongoing Cost of Service beginning in 2017. As the Ontario Budget estimates that the annual revenues the Province will collect under this program could amount to $1.9 Billion annually, BPI is concerned that the introduction of this new Cap and Trade program will result in unrecovered Cost of Service beginning in 2017.

As Cap and Trade costs will result in new, previously non-existent, input costs to the manufacturing of equipment, goods and materials purchased by BPI, it is reasonable to expect that suppliers will adjust their pricing to recover these new additional carbon costs. At this time, there is insufficient information available to allow BPI to predict or forecast the impact of the Cap and Trade program in its proposed Cost of Service. It is expected that the nature of this program will be sufficiently broad that it will impact both capital costs and OM&A. Examples of costs that BPI expects are likely to be impacted by Cap and Trade costs are the following:

- Fuel used in the operations of the fleet and to heat facilities;
- The cost of significant manufactured goods e.g. transformers, fleet vehicles other materials used in the distribution system that is manufactured and transported;
- Increases in fees and charges by other government agencies and service providers who must pass on their cap and trade impacts to their respective customers or clients.

IR: 9.0 –VECC -47

Reference: E9/T1/S1/pgs4- RSVA

a) Please provide the relevant pages of the 2013 settlement agreement (EB-2013-0109) which pertain to the issue of the 284k being sought for recovery. Please also provide the related Board Staff interrogatory noted in the evidence and the evidence showing the RSVA balances in EB-2013-0109.

Response:

BPI provides the following from EB-2012-0109:

Attachment 9-VECC-47a: Issue 9.1 from Settlement

Attachment 9-VECC-47b:2013 Interrogatory Response.

IR: 9.0-VECC-48

Reference: E9/T1/S5/section 9.1.5

Pre-amble: At section 9.2 of the settlement agreement in EB-2012-0109 there is the following provision: "*In its application, BPI requested an accounting order to authorize the creation of a variance account to capture specifically defined differences related to BPI's future transition to International Financial Reporting Standards ("IFRS"). The variance account was proposed to track gains or losses on disposition of plant property and equipment as well as other postemployment benefits. For the purposes of settlement, the Parties agreed that BPI will no longer request this deferral and variance account*."

a) Please explain how the recovery sought at section 9.1.5 is consistent with this agreement.

Response:

The recovery requested is fully consistent with this agreement. The basis for withdrawing the request during the 2013 Cost of Service proceeding is the fact that no variances would have been created until such time as BPI transitioned to IFRS. Since BPI did not plan to transition to IFRS at anytime during the 2013 Test Year, the need for a variance account in that proceeding was premature and therefore BPI agreed to withdraw.

BPI contends the agreement context limited the item to the 2013 Cost of Service proceeding and did not preclude BPI from requesting future accounting orders relating to IFRS should any be required following the transition to IFRS or prevent BPI from using and recovering variances recorded in Board approved IFRS related DVA accounts.

Attachments to Interrogatory Responses

Attachment 1-SEC-1: BPI Strategic Plan

DATE: November 21, 2013 **REPORT NO.** BPI-1311-003

TO: Brantford Power Board of Directors

FROM: Paul Kwasnik, CEO & President **–** Brantford Power Inc.

1.0 TYPE OF REPORT: **X For Decision (Recommendation required)**

For Discussion

For Information

2.0 TOPIC: Strategic Planning - 2014-2017 Goals and Strategies

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3.0 RECOMMENDATION

It is recommended that the Board of Directors approve the 214-2107 Goals and Strategies outlined in the attached document.

4.0 PURPOSE

To ascertain the approval of the Board for the corporate Goals and Strategies.

5.0 BACKGROUND

Brantford Power Inc. (BPI) has initiated a planning project to establish a strategic plan identifying directions for the period 2014-2017 and beyond. The new strategic plan has been developed with extensive involvement of BPI's shareholder, staff and members of the community.

Planning steps carried out to date include the following:

- In the spring of 2013, the BPI Board and CEO established project terms of reference and selected an external planning consultant to help facilitate the process. A work plan was approved in May.
- An "environmental scanning" phase involving an information review, meetings with key stakeholders, interviews with community key informants with the completion of a value propositions questionnaire was carried out in May and June.

- On June 19, 2013 the members of the BPI Board and Senior Leadership Team attended a full-day strategic planning session. They reviewed the environmental scan information and developed preliminary versions of BPI's strategic options and directions.
- A joint meeting with the BPI Board and the Board of Brantford Energy Corporation was held on August 8, 2013 to review the discussion paper and respond to specific focus questions posed by BPI. The developed strategic plan incorporated the input from the BEC Board and provided for additional business case analysis of the selected options.
- The draft strategic plan and illustrative business analysis of selected future directions was presented to the BPI Board on September 26, 2013 and was reviewed in a follow-up joint BPI/BEC planning meeting on October 3, 2013.
- Based on this work a prioritized list of five Goals and Strategies has been formulated and are recommended for approval.

6.0 INPUT FROM OTHER SOURCES

SLT- Brantford Power Inc.
David Sheridan – SherCon Consultant.

7.0 STRATEGIC PLANNING CONTEXT - NA

8.0 ANALYSIS

See attached document for details of 2014 – 2017 Strategies and Goals.

9.0FINANCIAL IMPLICATIONS

N/A.

9.0 CONCLUSION

BPI is entering into the final phase of its strategic planning process for the next three years. Upon approval of these Strategies and Goals, is a critical milestone and next steps that include the formulation of Key Performance Index criteria and measurements that will be presented to the Board of Directors in December. Approval of these five Strategies and associated Goals at this time will provide context for directions that BPI will take in setting budgets; establishing organizational and departmental objectives and building a common message to Employees; Customers; Shareholder and Regulator for the future. Consequently, we are recommending the Board of Directors approve the accompanying recommendation.

10.0 Signed by:

Paul Kwasnik
CEO & President

BRANTFORD POWER INC.
Strategic Plan for 2014-2017

Mission Statement

Brantford Power is driven to be a leading electricity distribution company by providing safe, reliable and competitively priced services to our customers, while ensuring excellent shareholder returns**.**

Values

Safety
Openness and integrity in all relationships
Innovation and creativity
A customer focus
Employee engagement

Goals and Strategies

1.0 <u>Develop all aspects of the organization through investment in human capital including safety, performance management, staff succession, training and development and organizational culture change</u>.

- 1.1 Continue to build on the ongoing commitment to a safe operation for employees and customers
- 1.2 Implement a new performance management system
- 1.3 Engage and develop the leadership team
- 1.4 Enhance internal communication initiatives

2.0 <u>Grow the business by directing capital to industry levels by increasing our systems, facilities, technology, customer base and infrastructure</u>.

- 2.1 Pursue acquisitions, amalgamations and mergers advantageous to BPI and its customers
- 2.2 Implement findings from the system integration study
- 2.3 Pursue a single building option
- 2.4 Explore distribution systems that attract new customers

3.0 <u>Pursue operational efficiencies, service excellence and quality across the organization</u>.

- 3.1 Implement meter to cash recommendations
- 3.2 Conduct further analysis and review of key operational areas
- 3.3 Improve customer service business policy, practices and procedures
- 3.4 Improve communication across the business re: customer value process
- 3.5 Develop a systematic continuous quality improvement program

… Cont'd

Goals and Strategies (Cont'd)

4.0 Raise community visibility and establish the BPI brand.

- 4.1 Continue/enhance existing public relations initiatives
- 4.2 Improve BPI's profile at community events
- 4.3 Increase customer communication and engagement
- 4.4 Develop and implement a marketing and branding program

5.0 Adopt a larger role in energy efficiency and conservation.

- 5.1 Continue meeting existing OPA targets
- 5.2 Develop a business plan to deliver CDM
- 5.3 Increase BPI industry level advocacy on energy issues

Timing and Deliverables

Goal 1.0 – Human Capital

	Strategy	**2014**	**2015**	**2016**
1.1	Continue to build on the ongoing commitment to a safe operation for employees and customers	→	→	→
1.1	Implement a new performance management system	x	→	→
1.2	Engage and develop the leadership team	x	→	→
1.3	Enhance internal communication initiatives	→	→	→
Year One Deliverables: Continued compliance with ZeroQuest accreditation; PM system designed and training underway; targeted leadership team candidates participating in professional development initiatives; internal communication improvement.				

Goal 2.0 – Business Growth

	Strategy	**2014**	**2015**	**2016**
2.1	Pursue acquisitions, amalgamations and mergers advantageous to BPI and its customers	x	→	→
2.2	Implement findings from the system integration study	x	x	
2.3	Pursue a single building option	x	x	x
2.4	Explore distribution systems that attract new customers	→	→	→
Year One Deliverables: Participation in one acquisition/ amalgamation/merger; identification of one other opportunity; identified customer-specific distribution system investments. Detailed execution plan of SIS including assessment of timing, prudency and resourcing of implementing recommendation. SIS resources assigned; completed building feasibility study.				

…Cont'd

Timing and Deliverables (Cont'd)

Goal 3.0 - Efficiencies

	Strategy	2014	2015	2016
3.1	Implement meter to cash recommendations	x		
3.2	Conduct further review and analysis of key operational areas	x	x	→
3.3	Improve customer service business policy, practices and procedures	x	x	→
3.4	Improve communication across the business re: customer value process	→	→	→
3.5	Develop a systematic continuous quality improvement program			x
Year One Deliverables: Work plans for MTC recommendations; identified areas for further study; new CS phone system; practices and scripts; training underway				

Goal 4.0 – Community Visibility

	Strategy	2014	2015	2016
4.1	Continue/enhance existing public relations initiatives	→	→	→
4.2	Improve BPI's profile at community events	x	→	→
4.3	Increase customer communication and engagement	x	→	→
4.4	Develop and implement a marketing and branding program		x	→
Year One Deliverables: Enhanced website; increased community event resources; new customer initiatives				

Goal 5.0 – Energy Efficiency and Conservation

	Strategy	2014	2015	2016
5.1	Continue meeting existing OPA targets	x		
5.2	Develop a business plan to deliver CDM	x	→	→
5.3	Increase BPI industry level advocacy on energy issues	→	→	→
Year One Deliverables: Completed business plan; advocacy messages and strategies				

November 14, 2013

Attachment 1-SEC-2-A: 2016- 2017 and multi-year forecast Budget Report for BPI Board

DATE: **December 16, 2015** **REPORT NO. BPI-1512-002**

TO: **Mr. Scott Saint, Chair and Directors**

FROM: **Brian D'Amboise, CFO & VP Corporate Services**

1.0 TYPE OF REPORT:

☐ **For Decision**

☐ **For Discussion**

☒ **For Information**

2.0 TOPIC: 2016-2017 BUDGET AND MULTI-YEAR FORECAST UPDATE

3.0 RECOMMENDATIONS

That the Brantford Power Inc. (BPI) Board of Directors approve the proposed 2016 Budget and Multi-Year forecast and recommend its approval to the Brantford Energy Corporation Board of Directors.

4.0 PURPOSE

To present to the Board of Directors for approval a proposed 2016 Budget and Multi-Year forecast with related background and explanatory information.

5.0 BACKGROUND

Management presents annually to the Board for approval, a proposed budget for the next fiscal year and financial forecasts for the subsequent four years. This year, Management is preparing a budget for both the 2016 and 2017 fiscal years and forecasts for 2018-2020. This is required as BPI must establish its expected cost of service to incorporate in the 2017 Cost of Service Rate Application scheduled to be filed with the Ontario Energy Board (OEB) in April 2016.

Although Management will be submitting budgets for both 2016 and 2017 fiscal years at this time, the approvals will represent approval of the 2016 Budget for next year as normal and a notional approval of the 2017 financial plan that will be incorporated into the 2017 Cost of Service rate application. Management will present for final approval in the fall of 2016, an updated 2017 Budget and Multi-Year forecast.

This updated budget is expected to be substantially in keeping with the 2017 financial plan approved this year as that will have been the basis of the rate application and resulting funding. However, it will be refreshed to reflect updated information available at that time.

Management provided a 2016-2017 budget update report at the October Board meeting. This current report will provide the Board with an update on the key 2016-2017 budget issues along with commentary on how Management has addressed these issues in the budget proposal. By submitting this budget proposal for approval, Management believes it reflects a prudent financial plan that balances the interest of the key stakeholders in a manner that will support a successful 2017 Cost of Service rate application.

Once the 2016-2017 Budget and Multi-Year Forecasts is approved by the BPI Board, the Company is obligated to obtain the approval of its shareholder, Brantford Energy Corporation (BEC). Provided the BPI Board approves the budget proposal on December 16, 2015, the approval from BEC will be requested later on December 16, 2015 when the BEC Board is convened.

Competing non-discretionary priorities, staff turnover and modeling difficulties significantly challenged the Finance Department to complete the proposed 2016-2017 Budget and Multi-Year Forecasts in time for issuance to the Board in advance of the scheduled Board meeting. As a result, the budget has literally been completed immediately before issuance to the Board. Although the budget has been reviewed for completeness and accuracy, sufficient time was not available to complete all of the customary quality assurance checks typically performed. Should material anomalies be identified prior to the Board meeting, updates will be provided.

6.0 INPUT FROM OTHER SOURCES

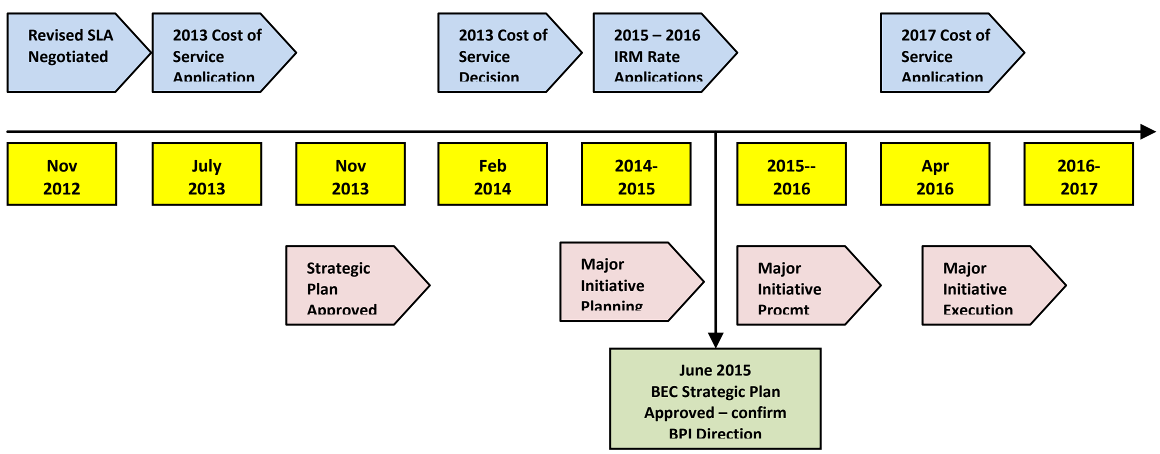
Not Applicable

7.0 STRATEGIC PLANNING CONTEXT

Before addressing the specific budgetary issues, it is important to review again with the Board the current trajectory of the business vis a vis the approved strategic plan and how those initiatives align with the distribution rate funding calendar established through current OEB Cost of Service rebasing schedules.

The chronology below reflects side by side the milestones related to BPI's strategic plan development and implementation in comparison to the scheduled timing of major rate funding adjustments achieved through rate rebasing achieved during OEB Cost of Service rate applications which occur on a five-year cycle. The proposed 2016-2017 Budget and Multi-Year Forecasts is prepared at a time where these two chronologies converge in 2016-2017. As reported in the October budget update, this timing has created some unique financial challenges in developing BPI's 2016 – 2017 Financial Plans.

Brantford Power Inc.
Chronology of Strategic Planning and Cost of Service Rate Rebasing



The Board will recall that the 2013 strategic plan approved five primary goals which set out a trajectory for the Company which fundamentally looked to accomplish growing and renewing the business. From a funding perspective, the 2013 Cost of Service rebasing was based on the previous BPI strategic plan priorities which was largely focused on a status quo operate and maintain agenda.

With a new strategic plan, the business' 2014 focus, in addition to core business functions and obligations, was largely to prepare plans and conduct research necessary to initiate the new strategic plan priorities. This was achieved by conducting research to develop work plans and approaches to achieve the strategic goals. For example, BPI completed a Systems Integration Study, issued RFI's for FIS and CIS, completed a Meter to Cash review, initiated Customer Satisfaction and Customer Engagement initiatives, and participated with the IESO and neighboring utilities to develop an Integrated Regional Resource Plans (IRRP) etc. These varied activities were necessary to set the stage for BPI to implement action items necessary to move the business towards these strategic goals.

Although most of these activities were not funded in the 2013 Cost of Service decision, productivity gains achieved through organizational changes and acceptance by the Board of unfunded budgetary provisions for these strategic initiatives enabled these activities to proceed.

As BPI moved into 2015, the Business began to convert these plans into actual projects. Most notable of these were related to the preparation of RFP's for FIS and CIS, implementation of E services, conducting research on alternatives for a consolidated location and finalization of the IESO's IRRP. These activities identified the investments required to move these initiatives forward again in support of the primary strategic objectives. As was the case in 2014, these items were not funded in the distribution rates established in 2013 but BPI budget provisions were established to move these strategic initiatives forward.

For 2016 and 2017, the Company is moving to the execution phase on some of these major initiatives. Common to many of these initiatives are the following:

- New capital investments over and above the traditional distribution plant investments – in some case these reflect material costs e.g. new facilities, or transmission system upgrade capital contributions;
- Additional financing charges to finance these new investments;
- Need for back fill resources or other third party supports to implement these major initiatives e.g. FIS and CIS;
- Overlapping expenses as new costs related to new initiatives will begin before the existing costs can be eliminated – for example:
    - Duplicate building services costs while new facilities are prepared for transition while staff continue to occupy existing facilities;
    - Existing IT costs continue while new costs are incurred on new systems during implementation and testing.

The significance of these realities is that 2016 is the last year where distribution rate funding levels remain at the 2013 Cost of Service level adjusted in 2015 and 2016 with IRM inflationary adjustments. It will not be until 2017 that the funding levels will be rebased to reflect the impact of these BPI renewal and investment initiatives.

It is important to appreciate that the funding model established by the OEB is largely expecting a steady state approach where an LDC's new initiatives can be funded from productivity gains. New investments can be funded from new debt room created by existing debt repayments and savings created as assets become fully depreciated.

With the scope of business renewal underway including material investment plans e.g. new facilities, FIS, CIS etc. the BPI funding levels in play for 2016 which were established during the 2013 Cost of Service Rate Application will not be at the desired levels. Nevertheless, Management has worked diligently to develop a 2016-2017 Budget and Multi-Year Forecast that accepts this reality, plans for proper funding adjustments in the 2017 rate rebasing process while being mindful of BPIs financial capacity to deliver the desired agenda and the customers' ability to pay.

In this regard, the proposed rebased distribution revenues in 2017 is projected to approximate the maximum 10% distribution rate increase allowed by the Ontario Energy Board without mandatory rate mitigation. At this level, BPI will not be able to recover 100% of its theoretical revenue requirement in 2017 leaving an estimated $1,000,000 in annual revenue requirement to the next rebasing period. This is not entirely unexpected given the materiality of the consolidated facilities.

It is also important to put the above 10% increase into context for the customer. A 10% increase in distribution charges is in fact a 2% impact on the total bill since the distribution portion represents only 20% of the total bill. Nevertheless, Management acknowledges the fact that customers have been burdened with numerous increases on their non-distribution elements of the bill in recent years and any new increases are likely not welcomed.

Management believes it is important to provide the Board under the strategic planning context of this report a view on how the convergence of rate funding and strategic planning execution time lines create an overarching budget issue which needed to be addressed in the preparation of the 2016-2017 Budget and Multi-Year forecast.

Although the preparation of a budget always involves trade-offs regarding priorities and timing, the convergence of BPI entering 2016 at the low point in the funding cycle while beginning to move into significant business transition costs and investments has presented BPI with financial challenges.

Management has attempted to keep the strategic plan agenda moving forward without jeopardizing the financial position of the business. This required balancing the following considerations:

- Short term financial performance;
- Regulatory risk with respect to the upcoming cost of service rate application;
- Impact on customers, and;
- Requirement to invest in the renewal of BPI.

8.0 ANALYSIS

8.1 ANALYSIS – Introduction

As a result of the funding cycle outlined in the previous section and the pending rate rebasing in 2017, it is essential that BPI consider not only the immediate requirements but also consider the years immediately after rate rebasing. This is the case because the base revenue established in 2017 will be the base funding envelope for the subsequent four years.

Although the 2017 budget is the basis for setting rates, there are some timing considerations driven by these regulatory realities that should be considered in creating the Company's multi-year financial plan. For example, the timing of major capital expenditures could influence when the regulated return is fully adjusted for this investment.

The following graphic illustrates the key elements that have been addressed in the proposed 2016-2017 budgets and multi-year forecasts:

Brantford Power Inc.
2016-2017 Budget and Multi-Year Forecast
Key Considerations

This budget report will highlight the key budget issues that impact the BPI's 2016-2017 financial plan and how they have been addressed. It will also provide a clear view of the expected financial outcomes that are being proposed.

As these issues are varied, one of the key challenges identified in the preparation of the 2016-2017 budgets is to understand and address the cumulative impacts of these matters. The resulting financial plan must provide for an outcome that accomplishes BPI's strategic priorities in a manner that also addresses the interests of the business, shareholder, regulator and customers. Management has also been mindful during the preparation of the budget to consider how these will impact the regulatory strategy for the 2017 Cost of Service Rate Application.

8.2 ANALYSIS – Distribution Revenues and load forecast

Prior to reviewing the specific issues being addressed in the 2016-2017 budgets, it is worthwhile to illustrate the rate funding issue raised in the strategic planning section. The current level of rate funding is based on the base level set during the 2013 Cost of Service Application. Because of the timing of the decision, BPI did not get an IRM adjustment in 2014 and received a modest adjustment in 2015.

The estimated top line revenue BPI will achieve based on the 2016 IRM rate order issued on December 10, 2015 represents an increase of 1.8% or approximately $289,000. This is the amount that is available to fund 2016 regular inflationary costs plus any new costs BPI will require to implement its strategic agenda.

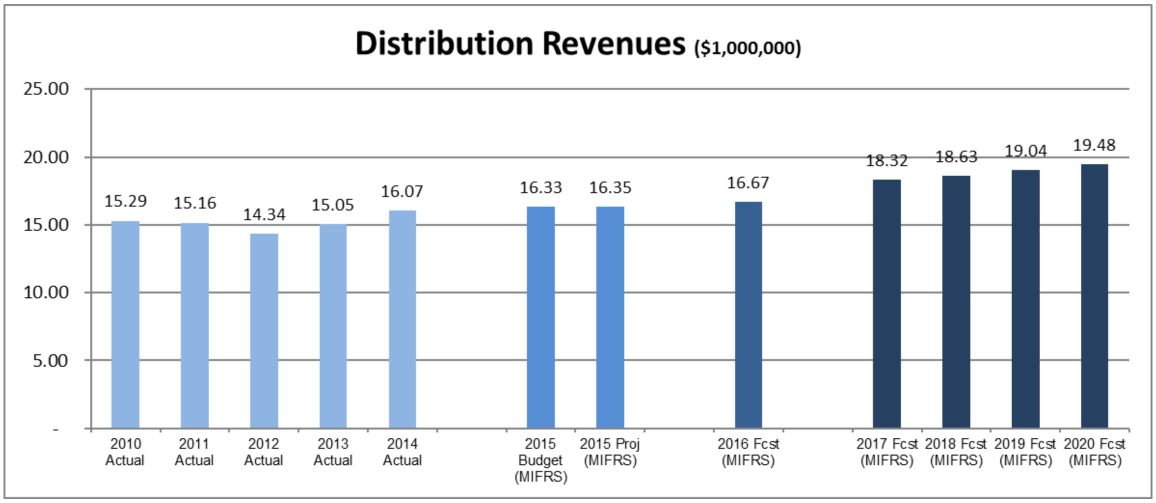
Clearly one of the primary challenges in developing the budget for 2016 was to produce a manageable 2016 financial plan that delivers the planned agenda without substantive revenue growth and a 2017 Cost of Service application that balances the need to reflect new rebased costs within the capacity of customers to absorb.

Details of the distribution revenue components have been reflected on Schedule F – Schedule of Commodity Recoveries and Other Revenues and Financial Expenses. In summary, the comparative distribution revenues can be summarized as follows:

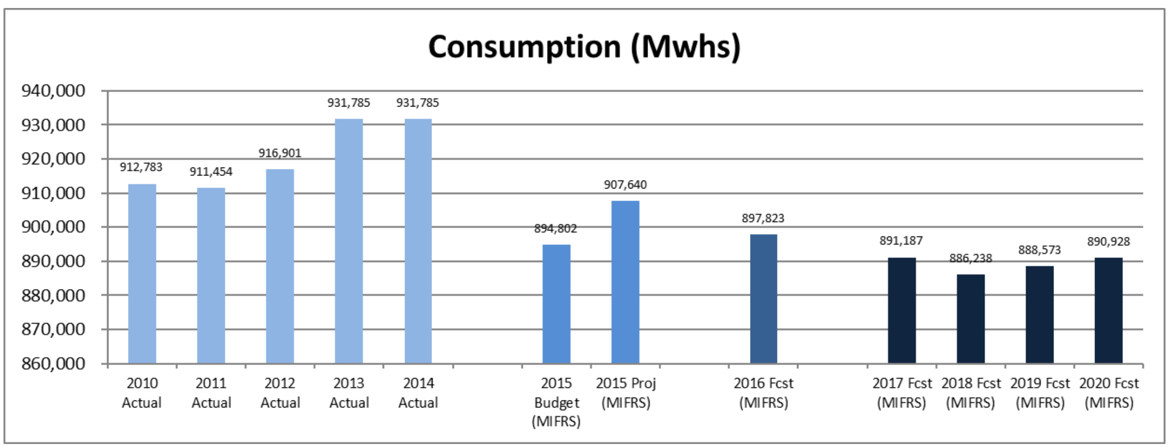
Brantford Power Inc.
2016- 2017 Budget & Multi-Year Forecast
Analysis of Distribution Revenues ($1,000)

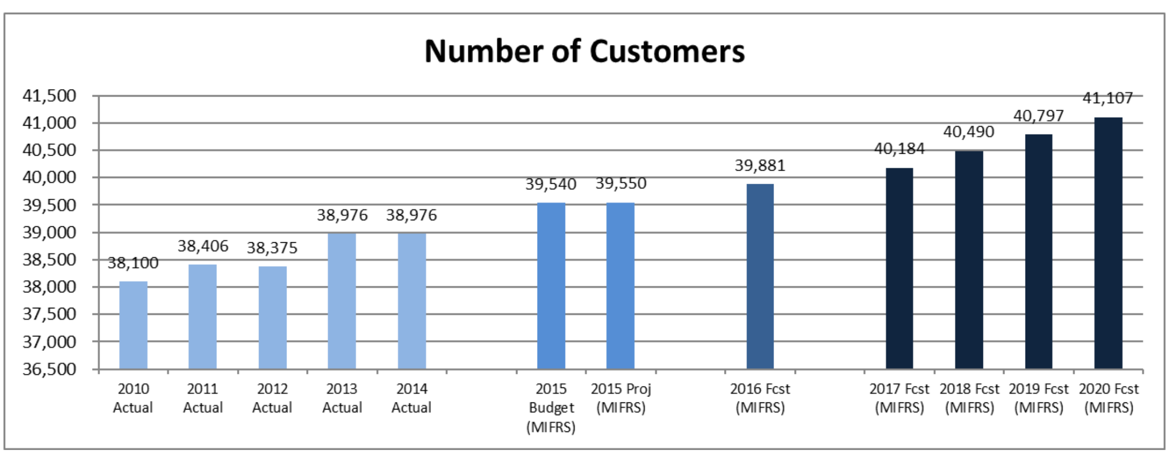
Component	2014 Actual	2015 Budget	2015 Projected	2016 Budget	2017 Budget
Base distribution Revenues	15,640	16,137	16,231	16,620	18,135
LRAM adjustments	116	207	133	61	201
Smart meter adjustments	310	(11)	(12)	(12)	(13)
Total	**$16,066**	**$16,333**	**$16,352**	**$16,669**	**$18,323**
% Change	**N/A**	**1.7%**	**1.8%**	**1.9%**	**9.92%**

Revenues beyond 2016 assume annual rate increases under IRM except for new Cost of Service rebased distribution rates in 2017.



The 2016 Budget and Multi-Year forecast assumes consumption levels, which are based on an internally developed load profiles taking into account a typical weather year and expected conservation impacts based on the new Conservation Framework targets. The results of this forecast are reflected in the following load and customer profiles:





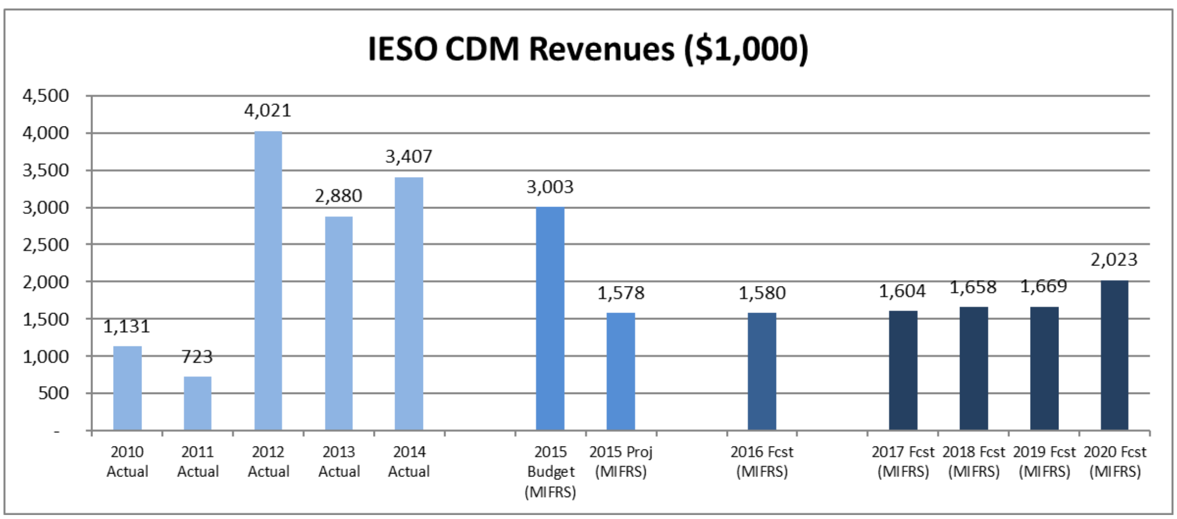
Refinements made to expected future consumption levels beyond 2016 indicates a stable consumption pattern in keeping with the objectives of the new Conservation Framework where limited growth is offset by conservation savings.

8.1 ANALYSIS – Conservation and Demand Management (CDM)

BPI recognized in 2015, $254,000 in Cost Efficiency Incentive on the Program Administration Budget under the previous 2011-2014 CDM Framework. As this is a one-time margin related to the 2011-2014 CDM Framework, the CDM program is forecasted to operate on a break even basis for the subsequent years.

BPI will be applying shortly to the OEB for a 2011-2014 CDM Framework performance incentive bonus since it met 168.6 % of its electricity savings (kWh) and 79.7% of its peak demand savings (kW) targets thereby meeting the eligibility threshold for these incentives. As this is subject to OEB review and award, Management has not reflected this additional performance incentive in the budget for 2016. Based on BPI calculations, the Company could be entitled to $293,520 which if approved would be recorded as an unbudgeted 2106 gain once approval has been confirmed. This is keeping with BPI's existing accounting policy for recognizing such incentives or bonuses.

The Board should note that the fluctuations in past OPA funding levels were largely influenced by the receipt and disbursement of the large cash flows provided for Ferraro's load displacement project.



8.3 ANALYSIS – OM&A Costs

The 2016 Budget provides for gross operating costs totaling $13,290,000 before allocations to the capital programs, CDM Programs or to affiliates for shared services. This represents a 12.5% or $1,475,000 increase over the 2015 gross operating costs of $11,814,000 reflected in the 2015 approved budget or a $1,966,000 or 17.4% over the 2015 Projections.

The 2016 Budget provides for net operating costs totaling $11,553,000 after allocations to the capital programs, CDM Programs or to affiliates for shared services. This represents a 13.1% or $1,346,000 increase over the 2015 budgeted net operating costs of $10,207,000 or a $1,923,000 or 20.0% increase over the 2015 Projections.

The increased in gross operating costs are attributable to a number of issues related to strategic investments and non-discretionary costs. Among these include the following:

- Increases in labor costs highlighted below including increased FTE's to address succession planning and strategic projects;
- An additional $220,000 in regulatory costs to cover the costs of the 2017 Cost of Service Application;
- A provision of $97,000 to cover the impairment of BGI service fees;
- An increase in the actuarially determined benefit expense for retirees of $70,000;
- An increase in overall facility costs of $198,000 largely the result of overlapping facilities during the last quarter of 2016 when new facilities are owned before BPI exits the existing facilities.

8.2 ANALYSIS – Labor Costs

There are number of issues that impacts the future labor costs for BPI which have been provided for in the proposed budget and multi-year forecast. Among the most significant are the following:

- Provisions to address renewed collective agreements which expire in the near term:
  - 2016 - IBEW & Association
  - 2017 – CUPE

  In this regard BPI has considered in this budget proposal BPI's competitive position for IBEW trade positions who at the expiry of their agreement will be the lowest paid tradespersons in the immediate geographic area and in some cases by a significant amount.
- Provisions for temporary staffing as back fill to major implementation projects e.g. FIS or CIS;
- Provisions to address succession planning on key operational roles both management and union in the technical areas of the business;
- The growing cost of employee benefits;
- Initial organizational changes necessary regarding SLA services to be patriated to BPI when the SLA expires in 2017 (Addressed in a separate SLA section below)
- The budget provides for some changes in the staffing complement to deal with new organizational requirements, succession planning or for project implementation as outlined below.

Brantford Power Inc.
2016-2017 Budget
Draft Proposed Staffing Complement

Department	2014 Actual	2015 Budget	2015 Projected	2016 Budget	2017 Budget
Senior Leadership Team	5.67	5.00	5.00	5.00	5.00
VP Operations & Engineering					
Engineering	8.00	8.00	8.67	9.00	9.00
Operations	17.24	17.00	17.67	18.50	19.00
VP Customer Service, CDM & Communications					
Settlement & Billing	5.00	5.00	3.33	5.00	5.00
Customer Service	13.74	14.58	15.33	12.92	13.92
CDM	2.00	2.00	1.63	3.00	3.00
Communications	0.70	1.00	0.69	0.69	0.69
CFO & VP Corporate Services					
Corporate Services	-	-	0.13	2.00	2.00
Regulatory	2.00	3.00	2.38	3.00	3.00
Finance	3.67	5.50	4.54	6.50	7.00
Total	**58.02**	**61.08**	**59.37**	**65.61**	**67.61**
Permanent FT	**54.29**	**55.00**	**54.00**	**57.25**	**59.00**
Permanent PT	**1.41**	**1.42**	**1.42**	**1.42**	**1.42**
Contract	**2.32**	**4.66**	**3.95**	**6.94**	**7.19**
Total	**58.02**	**61.08**	**59.37**	**65.61**	**67.61**

- The following reflect the highlights of the organizational changes contemplated in the budget:
  - Succession planning for anticipated retirements within the operations department including the provision of an additional supervisor in 2016;
  - Addition in 2016 of a Manager, System Projects and Business Applications to provide dedicated project management, training, system integration and training oversight as business processes migrate to new systems;
  - Addition in the CDM team to assist with the administrative elements of the programs;
  - The Finance Department and Customer Services Departments will continue to reflect additional temporary resources to backfill the planned FIS and CIS implementations.
- Although reflected in the Gross OM&A costs, there are recoveries for services provided to affiliates or for CDM activities which are funded from the IESO.

It is important to note in the graph below, that the increase in OM&A in 2013 from the levels in 2012 and prior was due to implementation of the OEB directive to adopt the IFRS approach to the capitalization of indirect overhead costs and to recognize the longer useful life of distribution assets. To put this change into perspective, BPI capitalized $843,000 of indirect overhead costs in its 2012 capital program.

The current trending on OM&A is as follows:

8.3 ANALYSIS – Service Level Agreement (SLA)

The current SLA arrangements with the City of Brantford are scheduled to expire on January 1, 2017. As a result, the 2016 and 2017 Budgets will need to reflect any transitions resulting from potential changes to this arrangement. At the present time, the budget is assuming the following:

- Cost effective SLA services should be renewed in 2017;
- Given the change agenda underway with FIS, CIS, possible new facilities, other SLA services should be renewed for at least 2017 with possible option for subsequent years to allow for cost certainty and reliable evidence in the 2017 Cost of Service application and to ensure the capacity to implement the change agenda on other big projects is not compromised;
- 2016/2017 changes have been limited to those required to optimize the functioning of the new FIS.

To the extent any services will be transitions to BPI, some overlap costs will be required as new business processes are set up, tested and implemented and especially where new staffing is required. With the plan of renewing services not impacted by FIS for 2017, the overlapping provisions have been limited.

8.4 ANALYSIS – System Integration Projects

The Board will recall that the original system integration report identified a number of projects that BPI should consider to achieve the necessary renewal to its IT infrastructure. As a result, the 2016-2017 Budget and Multi-Year forecast will reflect the anticipated costs for these initiatives as indicated below:

- Financial Information System (FIS) assuming it is operational by the end of 2016;
- Customer Information System (CIS) assuming it is operational by the end of 2017;
- Where detailed planning has not yet taken place regarding future System Integration initiatives, a flat rate budgetary provision (capital and operating) will be provided in each year to fund the remaining yet to be scheduled projects.

Where firm costs are not yet known, Management has utilized the best information available to establish suitable budgetary provisions.

Of the total $961,000 in special project costs provided for in the budget, a total of $709,000 is earmarked for System Integration Projects the largest being FIS in 2016 estimated at $588,000. As BPI has selected the hosted model for FIS, IFRS does not allow the capitalization of most elated implementation costs in these situations.

8.5 ANALYSIS – Consolidated Facilities

As this project is the largest material project BPI will encounter, the timing and costing is expected to have a significant impact on the business. As the timing of this project will have a significant impact on rates and shareholder returns, it is an ideal scenario that the Business is able to occupy the facilities in 2016. This will avoid being impacted by the half year rule, or require a more complex Advance Capital Module application in our rate application.

This initiative is the most pervasive item in the budget due to materiality and because operating costs is spread throughout the operating budget. Listed below are the key assumptions used to develop the budget regarding consolidated facilities. The assumptions are based on proceeding with the scenario that has been under consideration. Clearly the budget would be significantly impacted if this project did not proceed or if another site became available.

General:

- Acquire land & building with closing date of October 1, 2016.
- Assume all refurbishment costs can be capitalized, although a portion may need to be expensed.

Brantford Power Inc.
2016-2017 Budget and Multi-Year Forecast
Cost of Consolidated Facilities

Description	Amount
Acquisition cost	$10,800,000
Building refurbishments	4,475,000
Capitalized wages and expenses (Project Manager)	101,000
Total Cost	**$15,376,000**

In order to properly reflect the impact of the acquisition on the budget, the total cost must be componentized into specific asset groupings having specific useful lives to enable the proper calculation of depreciation amounts.

Brantford Power Inc.
2016-2017 Budget and Multi-Year Forecast
Total Costs Allocation to Asset Components

Description	Basis of Calculation	Amount
Building	What remains of acquisition cost + all other refurbishment costs	$7,770,000
Land	41 acres x $125,000/acre (as per estimated average land value per acre in Brantford)	5,125,000
HVAC	Based on estimate of Construction Costs/Site Improvements	1,451,000
Parking Lot	Estimate of acquisition price	500,000
Roofing	Estimate of acquisition price	300,000
Furnishings	Portion of acquisition price (60 people x $2,500/person)	150,000
Fencing	Based on estimate of Construction Costs/Site Improvements	80,000
Total Cost		**$15,376,000**

Building Occupancy (Total Space = 104,400 ft^2)
- Brantford Power - 37,000 ft^2 (based on Needs Assessment report)
- Brantford Hydro – 1,400 ft^2 (comparable to what is currently being occupied at BGI of 1,020 ft^2)
- Occupied by 3rd party – 10,000 ft^2 (based on current information)
- Excess space – 56,000 ft^2

Rental Income:
- Rental income of $19/ ft^2 (Based on rate used by COB for 84 Market rent of $12/ ft^2 + estimate of what is charged by COB for operational expenses through SLA of $7/ ft^2)
- Rental income commencing October 1/16 for tenants

Operating Costs:
- Estimate of $737,000 per year, increased by inflation of 2%. (Estimate determined by extrapolating 2015 actual facility operating costs that were provided for Jan –Aug 2015 (8 months).
- Costs are pro-rated in 2016 at 3/12 mths (consistent with acquisition date of Oct 1/16).
- SLA services (rent & operational expenses) ending Dec 31/16, with COB budget for 2016 used, totaling $574,902.

Loan Details:
- Principal Amount - $13,837,800 (90% of total capitalized building costs)
- Amortization Period – 30 yrs
- Interest Rate – 5%

Distribution Revenue Impact:

- Full value of building included in rate base despite larger than required on the basis that a green field build would have cost the same amount;
- Operating costs limited to proportion used by BPI;
- Total annual revenue requirement impact net of savings from current facilities $1,345,000 which translates to 5.02% increase in required distribution revenues;
- Unable to determine impact on various customer classes until rate design is completed following cost allocations of budget requirements to each customer class.

In addition to the OM&A elements, the impact of the new consolidated facilities will also result in an increase in annual financing charges approximating $230,000 and amortization of $300,000.

As this project is material, it will carry a degree of regulatory risk as the interveners will want to ensure customer contributions are limited to only those investments that were required for distribution purposes.

8.6 ANALYSIS – BGI Implications

With the ongoing challenges in BGI not yet resolved, the question of BGI shared service recoveries is an issue for BPI. Since it is not clear whether BGI will be a going concern and for how long, the budget will reflect ongoing support fees to BGI for shared executive and finance support. However, these charges will be offset with impairment allowances for budget purposes.

Since BPI may not recover service fees from BGI in the future, the 2017-2020 Budget and Forecasts although continuing to reflect impairments has the same effect as BGI no longer receiving services and these previously shared costs will become a cost of service to BPI.

Any existing and ongoing outstanding BGI affiliate charges will be offset by impairment allowances charged to non-utility accounts which do not impact customers. This is not theoretically a detriment to BPI as the 2013 Cost of Service rates were based on BPI not providing any services to any affiliates.

The projected 2016 BGI impairment allowance amounts to $97,000 (2015-$128,000).

8.7 ANALYSIS – BEC Implications

The budget for BEC Management fees reflects the impact of the restructured BEC Board of Directors and updated costs for shared executive and financial management costs. A full review of all other BEC Group intercompany allocations has been updated and re-calibrated based on current cost causation drivers.

8.8 ANALYSIS – Customer Engagement

With the introduction of the OEB's Renewed Regulatory Framework focused on customer outcomes, LDC's have been required to focus on a number of non discretionary customer engagement activities including mandatory customer satisfaction surveys, need to demonstrate that rate applications and distribution system plans reflect customer preferences and most recently the requirement to measure public electricity safety awareness. The budget has provided costs to meet these requirements.

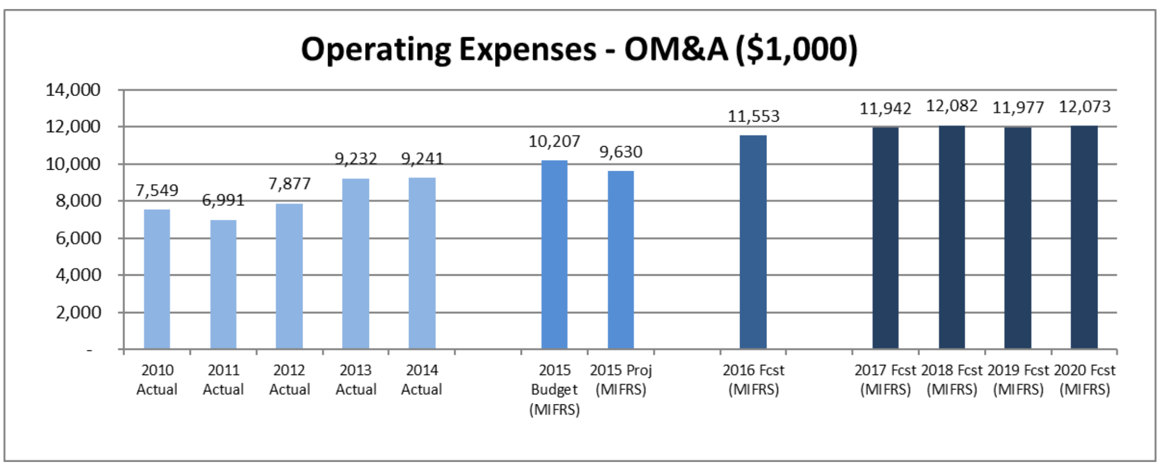
8.9 ANALYSIS – SPECIAL PROJECTS

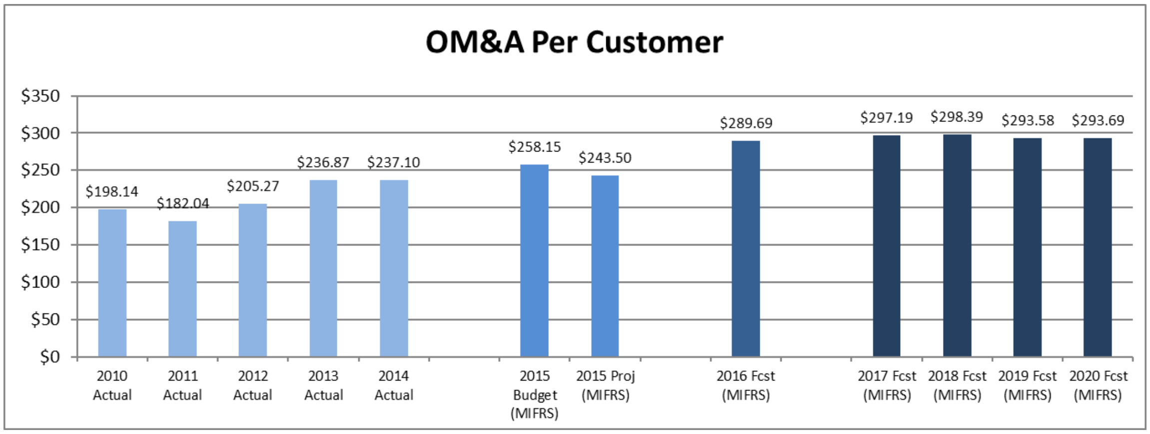
The financial plan provides a total funding of $961,000 for 2016 special projects. As previously outlined the most significant of these is the investments for FIS and other system integration initiatives totaling $709,000. The remaining 2016 funding of $252,000 provides funding for a number of initiatives including:

- Funding to obtain assistance to review and update BPI Policies;
- Funding to provide additional training;
- Funding to improve employee engagement
- Funding to refresh the current budget modelling that have been in use for a decade to address performance issues encountered in preparing this year's budgets and to reflect the impact of a new FIS with improved budget functionality.

8.10 ANALYSIS – OM&A Summary

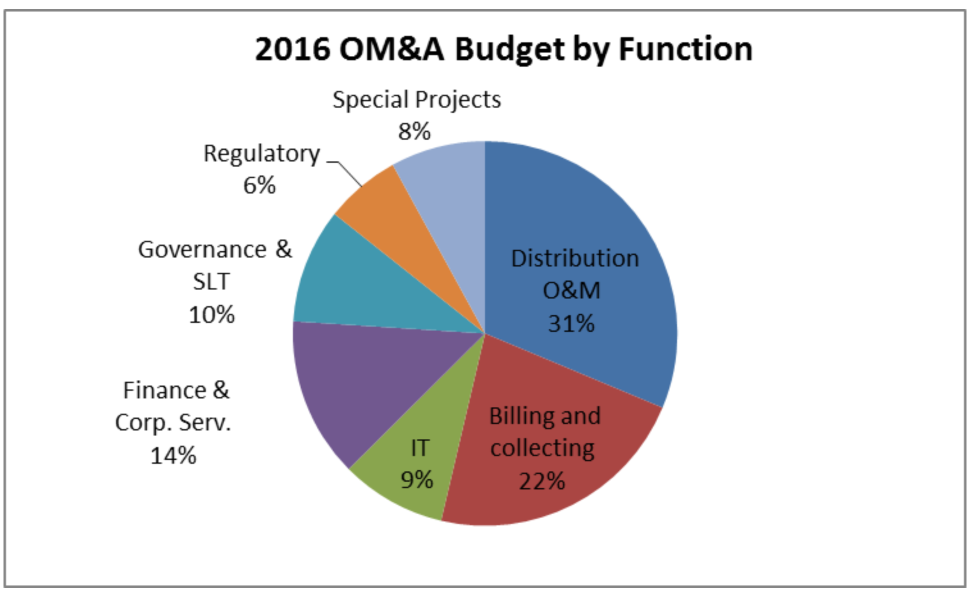
As previously outlined in the strategic considerations above, BPI is embarking on a number of strategic initiatives which impact the overall OM&A envelope in 2016 and the near term.





With the continued cost pressures created by new customer engagement obligations, increasing regulatory compliance costs, the higher costs for skilled labour due to the strong market competition for these scarce resources, limited capitalization opportunities under IFRS and other regular inflationary cost pressures combined with the inability of customers to absorb additional costs means BPI will need to find efficiencies in other areas.

The following pie chart indicates that BPI spends approximately $4.1 million or 31.0% of total OM&A on billing and collecting and IT which is an amount similar to the $4.2 million currently spent to operate and maintain the distribution system.



With the pending implementations of FIS and CIS over the next three years, BPI will have a real opportunity to review and modernize these business processes in order to provide efficiencies and related savings to redeploy funds to other priority functional areas.

8.11 ANALYSIS – Capital Plan

The proposed capital plan which will be supported by a Distribution System Plan that will be filed with the 2017 rate application will reflect prudent investments including the following:

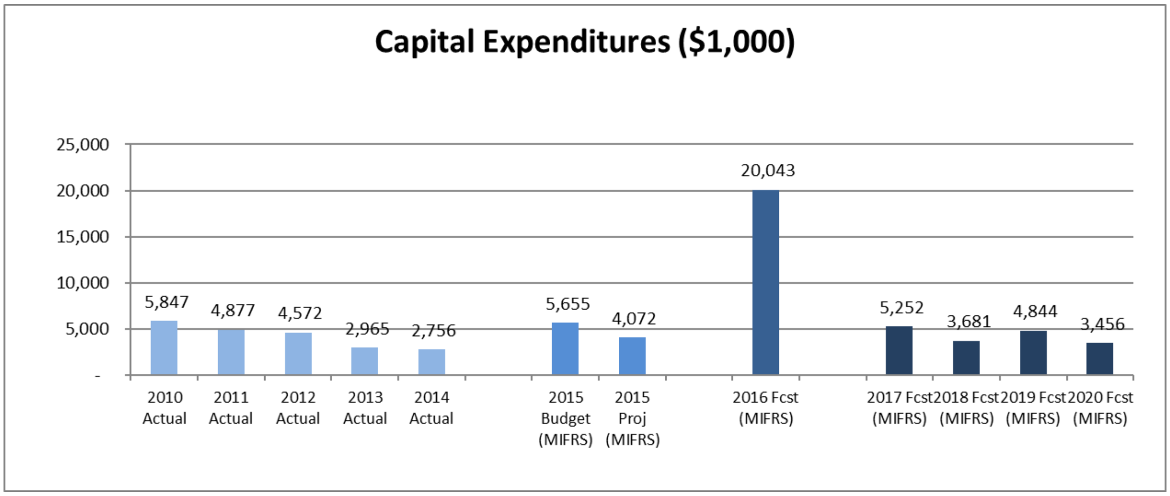
- New consolidated facilities;
- Capital contributions towards upgrades to the Transmission system in keeping with the Integrated Regional Resources Plan (IRRP) recommendations;
- Priority projects identified from BPI's asset management program;
- Expected investments for new customers;
- Other investments necessary to respond to customer concerns raised during the various customer engagement initiatives.

With the first two large one-time items, the total forecasted capital spending will be greater than those expended in recent years. Although increased investment is conducive to the "Grow the Utility" objective in the strategic plan, the budget proposal has attempted to balance this objective with its own financial capacity and the capacity of customers to absorb resulting rate increases.

Brantford Power Inc.
2016-2017 Budget and Multi-Year Forecast
Summary of Capital Expenditures ($1,000)

OEB Categories	2014 Actual	2015 Budget	2015 Proj.	2016 Budget	2017 Budget	2018 Fcst	2019 Fcst	2020 Fcst
System Access	$506	$584	$953	**$796**	**$925**	$958	$1,217	$1,111
System Services	1,113	1,731	$1,959	**2,745**	**3,227**	1,452	1,208	1,188
System Renewal	960	737	$629	**440**	**323**	588	1,907	822
General Plant	176	2,604	$531	**16,062**	**776**	593	512	335
Total	**$2,756**	**$5,655**	**$4,072**	**$20,043**	**$5,252**	**3,681**	**$4,844**	**$3,456**

Schedule E provides a summary of the specific projects that are earmarked in the 2016-2017 Budget and Multi-Year Forecast. The following graph illustrates the planned capital program.



8.12 ANALYSIS – Financing

With the acquisition of a new building, capital contributions on transmission system upgrades, BPI will need to finance portions of its planned capital spending in 2016 and beyond. The objective in the financial plan will be to return BPI to the targeted 57% debt level.

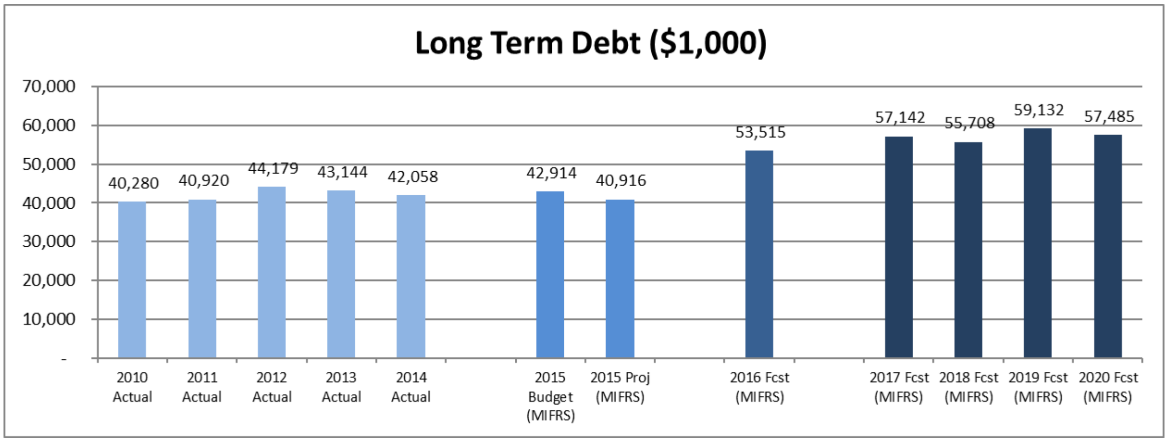
One item of concern is the fact that Infrastructure Ontario (IO) has indicated that they are not prepared to lend additional funds to BPI until BGI circumstances have been resolved. Depending on the timing, BPI may need to obtain financing from traditional lenders. At issue is the fact that currently, Royal Bank, Infrastructure Ontario and the City of Brantford have sequential rights to BPI's assets pursuant to respective General Security Agreements.

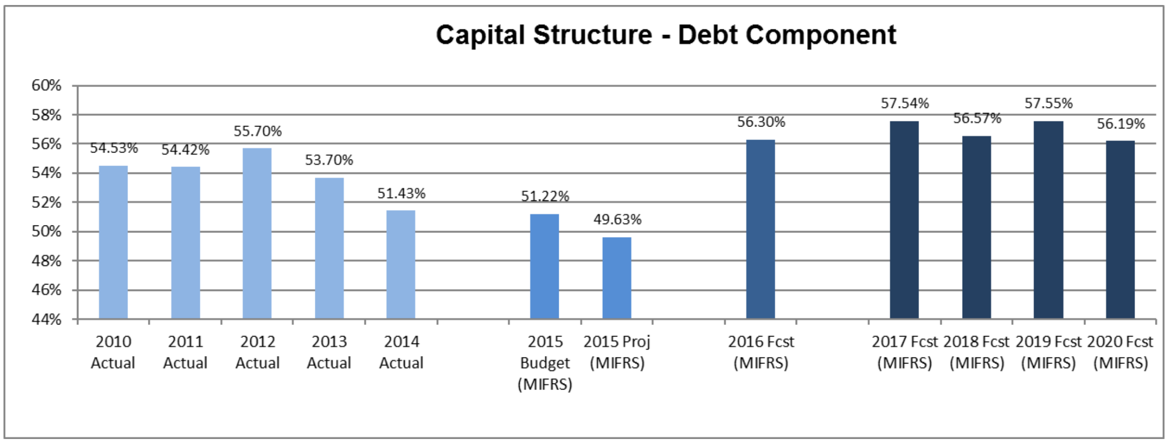
As IO retains certain approval rights any new lender would have to be subordinated to 3rd or possible 4th level for access to assets under the GSA. Some lenders are prepared to enter into a pari passu arrangement where all lenders share the security on new loans on a pro rata basis. Other LDC's have indicated IO has not always been prepared to accommodate new lenders.

As it is not certain that BPI could secure loans from OILC, the financing plan has assumed the rates available from commercial financial institutions.

The current budget has illustrated financing of 90% of the building in 2016 and a further $5,000,000 in general capital financing in 2017. In addition to providing the funds for these investments, this new financing will return BPI's capital structure to the target debt level approximating 57% which is in keeping with the maximum 60% debt level prescribed by the OEB.

As these projects develop, the actual timing of the financing could change to accommodate the timing of the capital expenditures for example – a delay in purchasing consolidated facilities.





The financing costs are based on the existing debt portfolio reflecting the current actual rates. The current City promissory note of $24,189,000 was last renewed on February 1, 2011 and will carry the rate of 5.87% until January 31, 2016. Thereafter, the budget has assumed the rate will drop to 4.20% reflecting the prime plus 1.5% stipulated for renewals and identified by the OEB process during the last Cost of Service decision as the level appropriate to charge customers for this debt.

The Board should note that the payment of promissory note interest is directly to the City of Brantford while the dividends are paid to the Brantford Energy Corporation, which will need to consider payment to the City. The revised interest rate will save BPI $404,000 per year keeping in mind that the OEB will recalibrate distribution rates to fund this reduced amount.

The timing of these borrowings will also allow BPI to get a significant proportion of its known debt service costs built into the cost of capital incorporated into the 2017 rebased distribution rates.

8.4 ANALYSIS – SHAREHOLDER PAYMENTS

BPI has sustained a $750,000 dividend for a number of years. The budget provides for additional dividends to BEC as outlined below. With the recent approval of the BEC strategic plan, it is expected that BEC will incur additional costs related to engagement of professional services to provide advice and due diligence on possible strategic transactions. More recently, BEC required funding to support an affiliated company.

Management has built into BPI's financial plan an increased dividend that BEC could retain without impacting the dividends it pays to the City of Brantford to support financially other aspects of the BEC group activities. This avoids the need to increase BEC Management fees which are not recoverable from customers in any event.

The Board recently declared a $250,000 dividend to BEC in response to a BEC request for capital funding. The request was for $500,000 with an immediate requirement for $250,000. BEC obtained the initial request. Management has included in the financial plan the payment of the second $250,000 tranche in 2016 should BEC make the request in 2016.

The financial plan is not detrimentally affected by these additional dividends. The provision of these dividends served to achieve the desired recapitalizing BPI's Balance Sheet to its targeted 43% equity level from the 50.3% equity level projected for the end of 2015. In addition, the financial plan has been prepared in a manner that provides the necessary funding to BEC to allow the continuation of BEC's pass through of the annual $750,000 BPI dividend to the City of Brantford in each year of the financial plan.

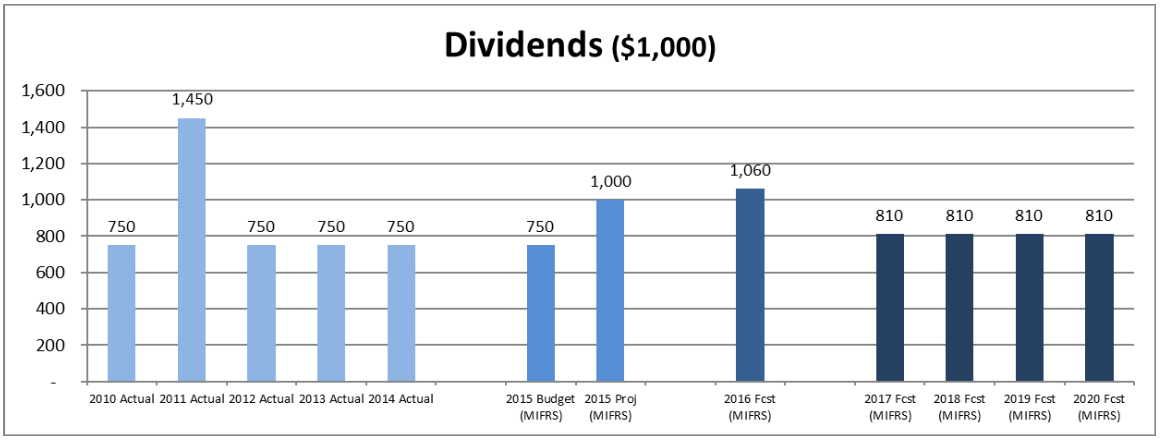
Based on the results in the 2016-2017 Budget and Multi-Year Forecast, the following payments are forecasted exclusive of any SLA payments for services rendered:

Brantford Power Inc.
2016-2017 Budget and Multi-Year Forecast
Summary of Dividends

Payments	2014 Actual	2015 Proj.	2016 Budget	2017 Budget
Based dividends	$750,000	$750,000	**$750,000**	**$750,000**
Regular enhanced dividends	-	-	**60,000**	**60,000**
One time dividends	-	250,000	**250,000**	**-**
Total Payments	**$750,000**	$1,000,000	**$1,060,00**	**$810,000**
Prior Year Reported Net Income	2,679,000	2,580,000	**2,589,000**	**1,044,000**
Total Dividend Payout % (Note 1)	30.0%	38.8%	**40.9%**	**77.6%**

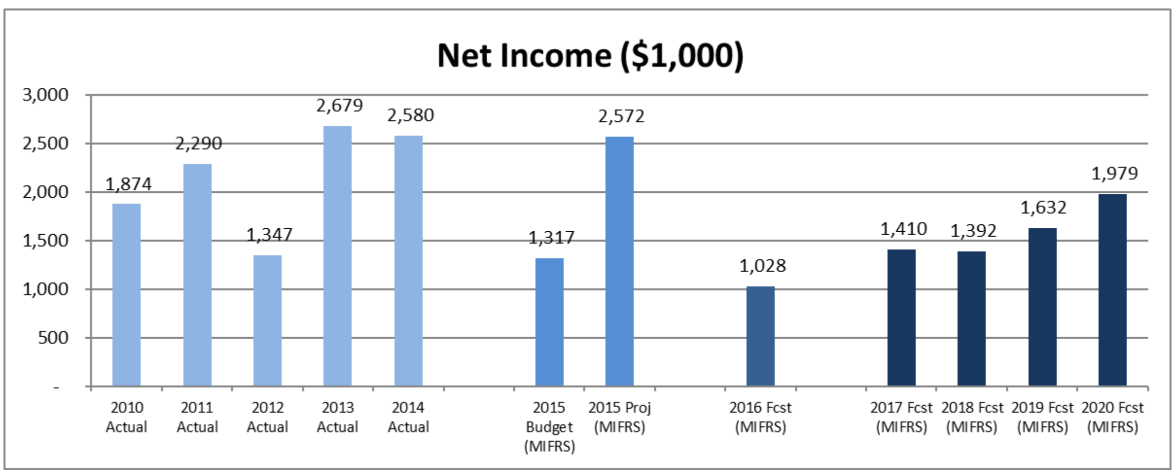
Note 1: *Dividend payout ratio is based on the current year payout divided over the prior year earnings. Many LDC's have specified dividend payout ratio from 50%-60%. Dividends at levels higher than these typical levels can be used to recalibrate the equity portion of the Company's Capital Structure.*

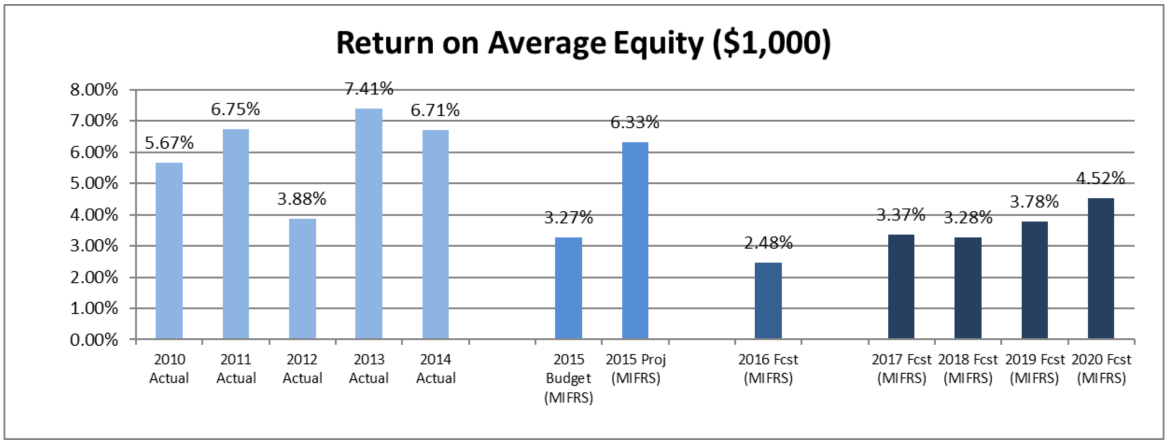
BPI's dividend record and forecast has been summarized below:



9.0 FINANCIAL IMPLICATIONS

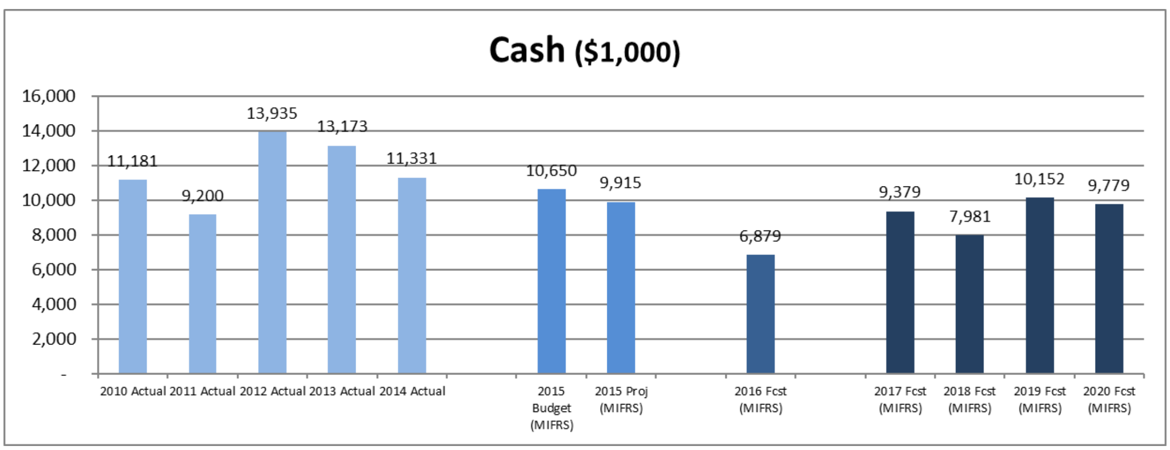
The 2016-2017 financial plan highlighted in this budget reflects significant investments contributing to the renewal of BPI. These new strategic investments combined with the higher transitional and one time costs in 2016 before rate rebasing has contributed to a lower targeted Net Income for 2016. Nevertheless, with the recent years of higher Net Incomes and the planned rebasing in 2017, this one modest year is not detrimentally impacting the longer term financial position of Brantford Power.



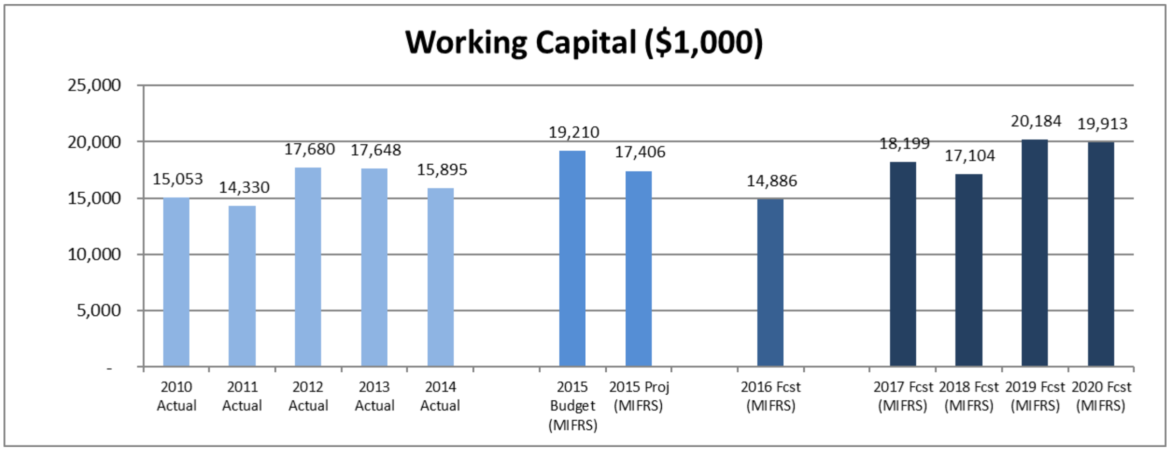


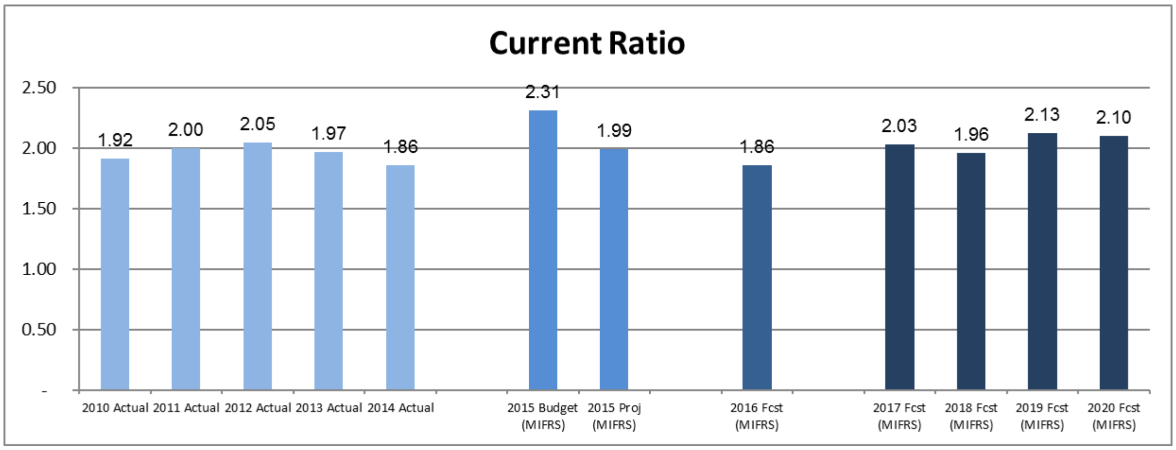
It is important to note that the lower than expected returns post rebasing in 2017 is largely due to the rate mitigation cap of 10% as BPI will be under collecting its theoretical revenue requirement until the subsequent next rebasing. In addition, the current financial plan reflects the fact that the ratepayers are not funding the BEC Management fees, BGI impairment provisions and the share of operating costs of the new building related to surplus space. This impact could be mitigated if BPI is able to find tenants for any excess space.

Based on the current 2016-2017 Budget and Multi-Year Forecast, BPI's financial position will remain solid despite the significant level of investment contemplated for 2016. With new financing, cash levels are expected to be lower than recent history but at levels providing sufficient liquidity.



The Company's' working capital levels reflect a relatively consistent level approximating a 2.0 current ratio throughout the 2016-2020 period.





In reviewing the Company's compliance with RBC and OILC debt covenants, the current forecast indicates that BPI is on side in every year. That year represents the year where BPI has an extraordinary level of capital expenditures with the largest capital costs for the new building.

In summary, Management believes the 2016-2017 Budget and Multi-Year Forecast reflects a base financial plan that focuses on short term investments required to implement the approved strategic plan with a goal of delivering longer term service and efficiency improvements. Such investments are necessary to enable sustainable and improving returns in the future.

10.0 CONCLUSION

Management believes the proposed 2016-2017 Budget and Multi-Year Forecast reflects a balanced financial plan which provides for a budgeted return that is below the level budgeted in 2015 largely due to the need for additional one-time costs required for BPI to pursue FIS and consolidated facilities.

Management has prepared a 2016-2017 Budget and Multi-Year forecast that reflects a prudent financial plan in keeping with the Company's strategic priorities. This plan maintains BPI's strong financial position while remaining mindful of the Customer's ability to pay.

10.0 CONCLUSION

This report has provided the Board with a complete briefing of the major budgetary issues and assumptions reflected in the proposed 2016-2017 Budget and Multiyear forecast. Management is recommending approval as it provides for a stable financial position while allowing for material investments necessary for the longer term effectiveness and sustainability of BPI.

Submitted by,
Brian D'Amboise,
CFO & VP Corporate Services

ATTACHMENTS:

COPIES:

Attachment A – 2016-2017 Budget and Multi-Year Forecast

Attachment 1-SEC-2-B: 2016-2017 Budget and multiyear forecast for BPI Board

BRANTFORD POWER INC.

2016

BUDGET AND MULTIYEAR FORECAST

BRANTFORD POWER INC.
2016 BUDGET AND MULTI YEAR FORECAST
BALANCE SHEET

	JAN 1, 2014 Actual	2014 Actual	2015 Budget	2015 Projected	2016 Budget	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast
ASSETS									
CURRENT ASSETS									
Cash and cash equivalents	14,650,132	11,331,058	10,650,219	9,915,249	**6,879,228**	9,378,927	7,981,133	10,151,645	9,779,120
Accounts receivable	9,275,129	10,357,405	10,807,000	11,058,802	**11,260,912**	11,774,843	12,129,545	12,651,499	12,784,329
Due from affiliates	2,960	57,454	10,866	7,465	**5,882**	6,101	5,640	5,718	5,728
Unbilled revenue	11,018,050	10,642,144	11,073,186	12,312,081	**12,488,512**	13,015,807	13,372,755	13,912,254	14,049,605
Inventories	859,915	853,548	757,500	940,000	**949,400**	958,900	968,500	978,200	988,000
Prepaid expenses	142,849	205,612	146,500	180,000	**181,800**	183,600	185,400	187,300	189,200
Payments in lieu of taxes payable	324,099	622,158	167,551	342,743	**266,667**	295,974	66,197	-	-
Future payments in lieu of corporate income taxes	207,230	238,500	214,120	198,750	**198,750**	198,750	198,750	198,750	198,750
	36,480,363	34,307,880	33,826,942	34,955,090	**32,231,151**	35,812,902	34,907,920	38,085,366	37,994,732
CAPITAL ASSETS									
Distribution plant	63,415,700	66,147,367	72,048,296	69,736,339	**89,750,189**	94,965,242	98,381,758	103,261,466	106,901,677
Other equipment	1,446,016	1,670,874	2,235,939	2,314,001	**2,822,361**	3,338,121	4,081,661	4,524,501	4,819,661
	64,861,716	67,818,241	74,284,235	72,050,340	**92,572,550**	98,303,363	102,463,419	107,785,967	111,721,338
Accumulated amortization	-	3,153,561	6,013,997	6,327,559	**9,744,907**	13,457,085	17,344,433	21,393,425	25,434,253
	64,861,716	64,664,680	68,270,238	65,722,781	**82,827,643**	84,846,278	85,118,986	86,392,542	86,287,085
OTHER ASSETS									
Regulatory Assets	6,656,238	6,643,746	5,521,374	7,707,125	**6,554,299**	5,541,392	6,129,382	6,907,960	7,717,129
Long-term prepaid expenses	22,770	10,350	5,000	5,000	**5,000**	-	-	-	-
Future payments in lieu of corporate income taxes	170,857	-	-	-	**-**	-	-	-	-
	6,849,865	6,654,096	5,526,374	7,712,125	**6,559,299**	5,541,392	6,129,382	6,907,960	7,717,129
	$ 108,191,943	$ 105,626,656	$ 107,623,554	$ 108,389,996	**$ 121,618,093**	$ 126,200,572	$ 126,156,288	$ 131,385,868	$ 131,998,945

BRANTFORD POWER INC.
2016 BUDGET AND MULTI YEAR FORECAST
BALANCE SHEET

	JAN 1, 2014 Actual	2014 Actual	2015 Budget	2015 Projected	2016 Budget	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast
LIABILITIES									
CURRENT LIABILITIES									
Accounts payable and accrued liabilities	12,931,070	13,961,133	9,729,353	13,003,290	**12,972,190**	13,093,419	13,217,320	13,007,600	13,137,700
Accounts payable to the City of Brantford	952,468	639,065	505,000	500,000	**505,000**	510,100	515,200	520,400	525,600
Accounts payable to affiliates	283,273	132,803	253,323	180,000	**253,323**	299,434	300,265	301,020	301,804
OPA funds received in advance	769,197	353,759	800,000	510,248	**515,400**	520,600	525,800	531,100	536,400
Interest payable to the City of Brantford	1,419,904	1,419,904	1,419,904	1,419,904	**1,049,608**	1,015,945	1,015,945	1,015,945	1,015,945
Payments in lieu of taxes payable	-	-	-	-	**-**	-	-	161,060	135,387
Current portion of long-term debt	1,038,479	1,088,567	1,141,429	1,141,429	**1,240,153**	1,372,907	1,435,845	1,578,040	1,650,874
Current portion of customer deposits	790,223	818,050	767,750	794,500	**809,870**	801,770	793,740	785,790	777,920
	18,184,614	18,413,281	14,616,759	17,549,371	**17,345,544**	17,614,175	17,804,115	17,900,955	18,081,630
LONG TERM DEBT									
Promissory note payable	24,189,168	24,189,168	24,189,168	24,189,168	**24,189,168**	24,189,168	24,189,168	24,189,168	24,189,168
Long-term debt	18,954,417	17,868,536	18,724,422	16,727,106	**29,325,754**	32,952,847	31,518,863	34,942,779	33,295,820
	43,143,585	42,057,704	42,913,590	40,916,274	**53,514,922**	57,142,015	55,708,031	59,131,947	57,484,988
OTHER LONG TERM LIABILITIES									
Regulatory liabilities	6,479,604	2,663,315	5,126,292	4,335,903	**3,985,267**	2,601,653	2,224,268	2,260,137	2,295,487
Deferred revenue (capital contributions)	-	439,812	592,287	587,183	**1,045,695**	1,492,003	1,926,107	2,348,007	2,757,703
Long-term customer deposits	679,929	637,041	594,000	650,000	**643,500**	637,070	630,700	624,390	618,150
Employee future benefits	1,077,901	1,205,061	1,203,187	1,234,130	**1,299,939**	1,273,940	1,248,461	1,223,492	1,199,022
Accumulated sick leave credits	92,262	106,410	90,105	111,380	**96,409**	97,169	61,896	18,448	18,079
Future payments in lieu of corporate income taxes	-	57,715	1,267,000	1,122,055	**1,809,063**	2,837,981	3,439,671	3,917,287	4,387,142
Derivative liabilities	372,285	333,600	346,500	350,000	**346,500**	343,035	339,605	336,209	332,847
	8,701,982	5,442,954	9,219,371	8,390,651	**9,226,373**	9,282,851	9,870,708	10,727,970	11,608,430
	70,030,181	65,913,939	66,749,720	66,856,296	**80,086,839**	84,039,041	83,382,854	87,760,872	87,175,048
SHAREHOLDER'S EQUITY									
Share capital	22,437,505	22,437,505	22,437,505	22,437,505	**22,437,505**	22,437,505	22,437,505	22,437,505	22,437,505
Retained earnings	14,545,965	16,375,909	17,587,708	18,165,175	**18,132,729**	18,733,006	19,314,909	20,136,471	21,305,372
Contributed surplus	141,319	141,319	141,319	141,319	**141,319**	141,319	141,319	141,319	141,319
Accumulated Other Comprehensive Loss	1,036,974	757,984	707,302	789,701	**819,701**	849,701	879,701	909,701	939,701
	38,161,763	39,712,717	40,873,834	41,533,700	**41,531,254**	42,161,531	42,773,434	43,624,996	44,823,897
	$ 108,191,943	$ 105,626,656	$ 107,623,554	$ 108,389,996	**$ 121,618,093**	$ 126,200,572	$ 126,156,288	$ 131,385,868	$ 131,998,945

BRANTFORD POWER INC.
2016 BUDGET AND MULTI YEAR FORECAST
STATEMENT OF INCOME AND RETAINED EARNINGS

	2014 Actual	2015 Budget	2015 Projected	2016 Budget	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast
REVENUES								
Distribution revenues (Schedule F)	$ 16,065,685	$ 16,332,546	$ 16,352,204	**$ 16,668,859**	$ 18,322,060	$ 18,631,008	$ 19,043,246	$ 19,478,429
IESO CDM funding (formerly OPA)	3,407,271	3,002,925	1,577,700	**1,580,232**	1,604,367	1,658,163	1,668,795	2,022,585
Other Revenues (Schedule F)	1,180,729	1,004,684	1,150,455	**1,127,841**	1,280,881	1,307,379	1,385,799	1,461,249
	20,653,685	20,340,155	19,080,359	**19,376,932**	21,207,308	21,596,550	22,097,840	22,962,263
EXPENSES								
Operations, maintenance and administration	9,241,182	10,207,181	9,630,496	**11,553,091**	11,942,122	12,081,791	11,977,021	12,072,539
IESO CDM expenditures (formerly OPA)	3,407,271	3,002,925	1,324,183	**1,580,232**	1,604,367	1,658,163	1,668,795	2,022,585
Interest on promissory note - City of Brantford	1,419,904	1,419,904	1,419,904	**1,049,608**	1,015,945	1,015,945	1,015,945	1,015,945
Interest on other long term debt	876,894	858,580	813,010	**823,110**	1,551,720	1,592,120	1,672,460	1,613,350
Other Financial Expenses (Schedule F)	77,766	128,561	77,955	**79,514**	79,514	79,514	79,514	79,514
Amortization	3,017,303	2,929,428	2,994,562	**3,197,164**	3,463,779	3,602,008	3,715,627	3,696,081
	18,040,320	18,546,579	16,260,110	**18,282,719**	19,657,447	20,029,541	20,129,362	20,500,014
INCOME BEFORE TAXES	2,613,365	1,793,576	2,820,249	**1,094,213**	1,549,861	1,567,009	1,968,478	2,462,248
INCOME TAXES (PILS)								
Current income taxes	(148,808)	(167,551)	189,878	**(76,789)**	(295,974)	(66,197)	161,060	296,447
Future income taxes	182,228	643,951	58,651	**143,448**	435,558	241,302	175,856	186,900
	33,420	476,400	248,529	**66,659**	139,584	175,105	336,916	483,347
NET INCOME	$ 2,579,945	$ 1,317,176	$ 2,571,720	**$ 1,027,554**	$ 1,410,277	$ 1,391,904	$ 1,631,562	$ 1,978,901
Retained Earnings - Beginning of Year	$ 14,885,257	$ 17,020,532	16,593,455	**18,165,175**	$ 18,132,729	$ 18,733,005	$ 19,314,909	$ 20,136,471
Net Income	2,579,945	1,317,176	2,571,720	**1,027,554**	1,410,277	1,391,904	1,631,562	1,978,901
Adjustments - IFRS conversion								
Write off City SLA long lived prepaids	(78,471)	-	-	**-**	-	-	-	-
Write off AOCI resulting from interest rate swaps	(260,822)	-	-	**-**	-	-	-	-
	17,125,909	18,337,708	19,165,175	**19,192,729**	19,543,006	20,124,909	20,946,471	22,115,372
Dividends	(750,000)	(750,000)	(1,000,000)	**(1,060,000)**	(810,000)	(810,000)	(810,000)	(810,000)
RETAINED EARNINGS, End of Year	$ 16,375,909	$ 17,587,708	$ 18,165,175	**$ 18,132,729**	$ 18,733,006	$ 19,314,909	$ 20,136,471	$ 21,305,372

BRANTFORD POWER INC.
2016 BUDGET AND MULTI YEAR FORECAST
STATEMENT OF CASH FLOWS

	2015 Budget	2015 Projected	2016 Budget	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast
CASH FLOWS FROM OPERATING							
Net Income	$ 1,317,176	$ 2,571,720	**$ 1,027,554**	$ 1,410,277	$ 1,391,904	$ 1,631,562	$ 1,978,901
Adjustments for non cash items							
(Gain)Loss on disposal of property, plant and equi	(23,000)	(24,500)	**(15,000)**	5,000	5,000	5,000	5,000
Amortization	3,065,246	3,155,789	**3,396,860**	3,679,486	3,842,452	3,991,892	3,971,524
Changes in non cash working capital	(1,159,870)	(2,995,990)	**(630,003)**	(938,075)	(357,780)	(1,044,339)	(166,180)
Future payments in lieu of corporate income taxes	643,951	58,651	**143,448**	435,558	241,302	175,856	186,900
Other items not affecting cash	25,638	1,356,068	**620,898**	579,656	306,207	239,947	264,754
	3,869,141	4,121,738	**4,543,757**	5,171,902	5,429,085	4,999,918	6,240,899
CASH FLOWS FROM INVESTING							
Proceeds on disposal of property, plant and equipment	23,000	24,500	**15,000**	15,000	15,000	15,000	15,000
Capital expenditures	(6,005,275)	(4,232,100)	**(20,522,210)**	(5,730,813)	(4,160,056)	(5,322,548)	(3,935,371)
Changes in regulatory assets	934,613	609,209	**802,190**	(370,707)	(965,375)	(742,709)	(773,819)
	(5,047,662)	(3,598,391)	**(19,705,020)**	(6,086,520)	(5,110,431)	(6,050,257)	(4,694,190)
CASH FLOWS FROM FINANCING							
Increase in customer deposits	(13,750)	(10,591)	**8,870**	(14,530)	(14,400)	(14,260)	(14,110)
Repayment of outstanding long term debt	(1,088,567)	(1,088,569)	**(1,140,428)**	(1,240,153)	(1,371,046)	3,566,111	(1,574,125)
Increase in long term borrowings	2,000,000	-	**13,837,800**	5,000,000	-	-	-
Capital contributions received	350,000	160,004	**479,000**	479,000	479,000	479,000	479,000
Dividends	(750,000)	(1,000,000)	**(1,060,000)**	(810,000)	(810,000)	(810,000)	(810,000)
	497,683	(1,939,155)	**12,125,242**	3,414,317	(1,716,446)	3,220,851	(1,919,235)
INCREASE/(DECREASE) IN CASH	(680,838)	(1,415,809)	**(3,036,021)**	2,499,699	(1,397,792)	2,170,512	(372,526)
CASH AT BEGINNING OF YEAR	11,331,058	11,331,058	**9,915,249**	6,879,228	9,378,926	7,981,134	10,151,646
CASH AT END OF YEAR	$ 10,650,220	$ 9,915,249	**$ 6,879,228**	$ 9,378,926	$ 7,981,134	$ 10,151,646	$ 9,779,121

BRANTFORD POWER INC.
2016 BUDGET AND MULTI YEAR FORECAST
SCHEDULE OF CAPITAL EXPENDITURES

	2014 Actual	2015 Budget	2015 Projected	2016 Budget	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast
DISTRIBUTION PLANT - REGULAR OPERATIONS								
Transformer station equipment	$ 611,516	$ 625,000	$ 669,997	**$ -**	$ -	$ 49,971	$ 150,002	$ -
Overhead distribution system	890,306	1,036,007	1,366,093	**874,059**	883,086	807,763	570,557	693,662
Underground distribution system	387,569	1,037,017	957,107	**886,458**	1,261,379	1,468,528	2,869,781	1,793,516
Line transformers	317,357	332,618	216,928	**348,224**	382,615	420,465	462,126	507,552
Services	136,646	90,715	170,590	**283,196**	369,867	410,600	430,579	441,047
Meters	(74,821)	173,584	110,000	**89,626**	90,508	91,389	259,763	94,034
Capital contributions paid	168,856	-	-	**1,875,750**	1,876,798	-	-	-
Work in progress	(4,679)	-	-	**-**	-	-	-	-
	2,432,750	3,294,941	3,490,716	**4,357,313**	4,864,253	3,248,716	4,742,808	3,529,811
Land and land rights	4,250	1,500,000	8,475	**5,125,000**	-	-	-	-
Leasehold improvements	13,573	-	12,549	**-**	-	-	-	-
Buildings and fixtures	3,855	500,000	-	**10,250,349**	-	-	-	-
	2,454,428	5,294,941	3,511,740	**19,732,662**	4,864,253	3,248,716	4,742,808	3,529,811
GENERAL PLANT								
Computer software	118,625	98,294	50,687	**189,188**	315,000	150,000	100,000	100,000
Computer and office equipment	21,277	81,040	26,545	**92,000**	35,800	17,800	36,900	10,400
Vehicles	118,016	380,000	405,000	**400,000**	400,000	400,000	350,000	225,000
Tools, communication equipment and load control	26,373	85,000	58,000	**25,000**	25,000	25,000	25,000	-
System supervisory equipment (SCADA)	348,895	66,000	180,127	**83,360**	90,760	318,540	67,840	70,160
	633,187	710,334	720,360	**789,548**	866,560	911,340	579,740	405,560
Capital Budget - Gross	3,087,615	6,005,275	4,232,100	**20,522,210**	5,730,813	4,160,056	5,322,548	3,935,371
CAPITAL CONTRIBUTIONS	(331,936)	(350,000)	(160,004)	**(479,000)**	(479,000)	(479,000)	(479,000)	(479,000)
TOTAL CAPITAL EXPENDITURES	$ 2,755,680	$ 5,655,275	$ 4,072,096	**$20,043,210**	$ 5,251,813	$ 3,681,056	$4,843,548	$ 3,456,371

BRANTFORD POWER INC.
2016 BUDGET AND MULTI YEAR FORECAST
SCHEDULE OF CAPITAL EXPENDITURES BY PROJECT

	2014 Actual	2015 Budget	2015 Projected	2016 Budget	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast
New Lines and Equipment								
New services (roll-ins)	$ 76,695	$ 190,715	225,000	**339,676**	465,329	410,600	430,579	441,046
New overhead line extensions	135,280	182,320	150,000	**191,436**	196,849	198,364	200,595	224,041
New underground line extensions	233,217	263,428	460,000	**276,599**	289,399	492,599	384,599	276,599
New overhead transformers	14,009	31,114	55,000	**31,645**	34,888	38,465	42,407	46,712
New underground transformers	283,592	277,879	277,879	**291,776**	321,682	354,652	391,009	430,686
Powerline feeder upgrades	518,223	450,000	576,000	**-**	-	-	-	-
New subdivisions and townhomes costs	269,708	566,400	310,000	**295,706**	739,250	783,605	857,530	872,315
City/MTO overhead relocation - general	36,732	23,186	40,000	**24,345**	26,841	29,592	32,625	35,969
City/MTO overhead relocation - Shellard Lane	278,761	-	18,037	**6,480**	23,210	136,000	-	-
Dalhousie St. - new build and relocates	-	7,025	2,000	**100,000**	-	36,800	1,500,000	-
Scada and distribution automation	154,796	146,000	180,121	**259,318**	272,593	426,299	211,447	201,207
Capacitor study and installation of line banks	28,415	625,000	680,000	**-**	-	-	-	-
Powerline TS	-	18,750	18,750	**-**	-	-	-	-
	2,029,428	2,781,817	2,992,787	**1,816,981**	2,370,041	2,906,976	4,050,791	2,528,575
Conversion - Ownership								
Poles, towers and fixtures	-	5,250	-	**5,513**	5,788	6,078	6,381	6,700
Overhead conductors and devices	-	5,250	-	**55,513**	55,788	6,078	31,381	31,700
Underground conductors and devices	78,666	23,625	-	**24,806**	26,047	27,349	28,716	30,152
Line transformers	-	23,625	-	**24,806**	26,047	27,349	28,716	30,152
	78,666	57,750	-	**110,638**	113,670	66,854	95,194	98,704
Rebuild of Existing Lines and Equipment								
Poles, towers and fixtures	188,648	210,000	140,000	**207,250**	199,574	207,250	199,574	207,250
Overhead conductors and devices	9,734	40,000	75,811	**200,600**	186,243	112,000	8,000	50,000
Underground conduit	87,017	43,500	139,977	**106,388**	91,219	108,177	78,936	79,898
Underground conductors and devices	59,145	33,038	15,756	**26,480**	20,000	20,000	20,000	534,550
Line transformers	182,021	-	215,259	**-**	-	-	-	-
	526,565	326,538	586,803	**540,718**	497,036	447,427	306,510	871,698
Metering								
Metering (meters and instrument transformers	133,310	173,584	110,000	**89,626**	90,508	91,389	259,763	94,034
	133,310	173,584	110,000	**89,626**	90,508	91,389	259,763	94,034

BRANTFORD POWER INC.
2016 BUDGET AND MULTI YEAR FORECAST
SCHEDULE OF CAPITAL EXPENDITURES BY PROJECT

	2014 Actual	2015 Budget	2015 Projected	2016 Budget	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast
Other								
Land and land rights	4,250	1,500,000	8,475	**5,125,000**	-	-	-	-
Building and leasehold improvements	13,573	500,000	12,550	**10,250,349**	-	-	-	-
Upgrade AM/FM & GIS system: asset management	108,175	30,000	12,250	**45,800**	15,000	49,970	-	-
Financial Information System (FIS)	3,500	-	-	**48,500**	-	-	-	-
Customer Information System (CIS)	-	-	-	**-**	135,000	-	-	-
Systems installation (Other)	-	-	-	**-**	100,000	150,000	100,000	100,000
Departmental contingencies	21,508	202,046	-	**-**	-	-	-	-
Office furniture, computer hardware and software	25,132	28,540	76,232	**186,888**	100,800	17,800	36,900	10,400
Large bucket and other	118,015	380,000	405,000	**-**	400,000	-	-	-
Small bucket and other	-	-	-	**350,000**	-	400,000	250,000	175,000
Vans, cars and pickups	-	-	-	**50,000**	-	-	100,000	50,000
Tools, communication equipment and load control u	30,172	25,000	28,000	**31,960**	31,960	29,640	123,390	6,960
WIP	(4,679)	-	-	**-**	-	-	-	-
Capital contributions paid	-	-	-	**1,875,750**	1,876,798	-	-	-
	319,646	2,665,586	542,507	**17,964,247**	2,659,558	647,410	610,290	342,360
Capital Budget - Gross	3,087,615	6,005,275	4,232,097	**20,522,210**	5,730,813	4,160,056	5,322,548	3,935,371
Capital contributions	(331,936)	(350,000)	(160,000)	**(479,000)**	(479,000)	(479,000)	(479,000)	(479,000)
CAPITAL BUDGET - NET	2,755,680	5,655,275	4,072,096	**20,043,210**	5,251,813	3,681,056	4,843,548	3,456,371
Strategic	-	3,485,000	1,651,997	**18,061,179**	2,848,355	792,942	559,840	483,162
Confirmed	2,755,680	591,119	665,024	**230,416**	604,577	680,532	653,070	625,326
Tentative	-	1,377,112	1,733,825	**1,576,615**	1,678,881	2,138,864	3,499,388	2,272,883
Contingency	-	202,044	21,250	**175,000**	120,000	68,720	131,250	75,000
	2,755,680	5,655,275	4,072,096	**20,043,210**	5,251,813	3,681,058	4,843,548	3,456,371
System Access	506,365	583,511	952,879	**795,913**	925,060	957,922	1,217,142	1,111,346
System Services	1,112,944	1,730,890	1,959,184	**2,745,329**	3,227,360	1,542,109	1,207,996	1,187,927
System Renewal	960,431	736,538	628,776	**440,118**	323,593	588,227	1,906,510	821,698
General Plant	175,940	2,604,336	531,257	**16,061,850**	775,800	592,800	511,900	335,400
	2,755,680	5,655,275	4,072,096	**20,043,210**	5,251,813	3,681,058	4,843,548	3,456,371

BRANTFORD POWER INC.
2016 BUDGET AND MULTI-YEAR FORECAST
SCHEDULE OF COMMODITY RECOVERIES AND OTHER REVENUES AND FINANCIAL EXPENSES

	2014 Actual	2015 Budget	2015 Projected	2016 Budget	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast
COMMODITY RECOVERIES								
Energy	$ 82,501,935	$ 92,128,085	$ 91,671,981	**$ 92,499,091**	$ 96,268,013	$ 99,631,505	$ 104,569,583	$ 105,390,730
Transmission	11,063,711	12,219,403	12,353,951	**11,631,970**	11,455,934	11,419,652	11,464,288	11,502,560
Wholesale market service charges	5,242,003	5,271,377	5,113,538	**5,278,767**	5,258,352	5,229,376	5,243,259	5,257,305
Retail settlement variance adjustment	803,782	(324,216)	(992,956)	**243,182**	245,697	254,800	273,324	290,937
	99,611,430	109,294,649	108,146,514	**109,653,010**	113,227,996	116,535,333	121,550,454	122,441,532
COST OF POWER								
Energy	82,786,972	91,206,804	91,689,450	**92,875,891**	96,651,018	100,021,958	104,978,434	105,817,304
Transmission	11,814,494	13,765,316	12,355,192	**12,026,229**	11,844,461	11,806,937	11,853,087	11,892,653
Wholesale market service charges	5,009,965	4,322,529	4,101,872	**4,750,890**	4,732,517	4,706,438	4,718,933	4,731,575
	99,611,430	109,294,649	108,146,514	**109,653,010**	113,227,996	116,535,333	121,550,454	122,441,532
	-	-	-	**-**	-	-	-	-
DISTRIBUTION REVENUE								
Revenue	$ 15,639,889	$ 16,136,697	$ 16,231,337	**$ 16,619,655**	$ 18,134,699	$ 18,319,048	$ 18,684,976	$ 19,065,079
LRAM adjustments	115,596	207,073	132,650	**61,360**	200,610	311,960	358,270	413,350
Smart meter adjustments - rate application	310,199	(11,224)	(11,783)	**(12,156)**	(13,249)	-	-	-
	$ 16,065,685	$ 16,332,546	$ 16,352,204	**$ 16,668,859**	$ 18,322,060	$ 18,631,008	$ 19,043,246	$ 19,478,429
OTHER REVENUES								
Specific service charges	$ 539,109	$ 432,715	$ 552,825	**$ 496,272**	$ 506,195	$ 516,317	$ 526,642	$ 537,172
Late payment charges	207,146	175,000	222,971	**226,236**	235,599	242,076	251,796	254,171
Bank interest income	173,887	145,000	142,710	**149,337**	125,846	122,422	168,342	219,034
Other interest income	(497)	2,000	7,400	**7,000**	7,140	7,283	7,429	7,578
Interest (expense) on regulatory assets	31,019	46,225	37,621	**14,444**	2,387	8,175	14,068	18,654
Property rental	108,645	107,727	97,575	**153,677**	322,449	329,452	335,477	342,187
Retailer recoveries	62,739	59,517	58,863	**50,875**	50,965	51,048	51,127	51,217
Gain on derivative liabilities	35,847	3,500	-	**-**	-	-	-	-
Other revenue	22,833	33,000	30,490	**30,000**	30,300	30,606	30,918	31,236
	1,180,729	1,004,684	1,150,455	**1,127,841**	1,280,881	1,307,379	1,385,799	1,461,249
OTHER FINANCIAL EXPENSES								
IESO fees	$ 65,336	$ 66,476	$ 65,336	**$ 66,643**	$ 66,643	$ 66,643	$ 66,643	$ 66,643
Interest on customer deposits and retailer prud	12,430	12,718	12,619	**12,871**	12,871	12,871	12,871	12,871
Amortization of Other Comprehensive Income	-	49,367	-	**-**	-	-	-	-
	$ 77,766	$ 128,561	$ 77,955	**$ 79,514**	$ 79,514	$ 79,514	$ 79,514	$ 79,514

BRANTFORD POWER INC.
2016 BUDGET AND MULTI-YEAR FORECAST
SCHEDULE OF OPERATIONS, MAINTENANCE AND ADMINISTRATIVE EXPENSES NET OF ALLOCATIONS

	2014 Actual	2015 Budget	2015 Projected	2016 Budget	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast
DIRECT EXPENSES								
DISTRIBUTION OPERATIONS AND MAINTENANCE								
Distribution operations and maintenance	$ 2,043,593	$ 2,088,772	$ 1,697,955	**$ 2,067,331**	$ 2,093,871	$ 2,143,884	$ 2,209,773	$ 2,242,680
Engineering operations and maintenance	855,307	979,235	957,358	**1,057,009**	956,119	975,937	987,095	999,998
Settlement	873,845	926,137	1,027,611	**1,540,928**	1,538,688	1,568,677	1,595,050	1,614,772
Engineering Services	337,715	400,000	342,731	**357,428**	365,034	372,335	379,783	387,377
Transformer Station operations and maintenance	99,673	113,728	98,197	**104,595**	103,919	105,325	105,552	105,792
	4,210,133	4,507,872	4,123,853	**5,127,291**	5,057,631	5,166,158	5,277,253	5,350,619
BILLING AND COLLECTING	-							
Customer Services	1,857,141	1,856,150	1,964,385	**1,715,136**	1,693,007	1,697,406	1,737,357	1,763,758
LEAP Program	20,407	21,000	21,000	**21,000**	25,000	25,000	25,000	25,000
Bad debts	366,783	306,000	123,647	**300,000**	300,000	300,000	300,000	300,000
	2,244,330	2,183,150	2,109,032	**2,036,136**	2,018,007	2,022,406	2,062,357	2,088,758
DIRECT GENERAL AND ADMINISTRATIVE	-							
Board of Directors	58,235	79,650	43,526	**39,088**	39,215	39,392	39,572	39,755
Senior Leadership Team	829,730	735,046	981,275	**982,785**	961,009	965,112	995,250	1,002,785
Finance	530,463	461,847	549,375	**634,716**	651,027	562,312	573,467	586,473
Corporate Services and Regulatory Affairs	325,953	471,330	413,375	**613,340**	400,203	415,169	430,808	447,122
Corporate communications	60,398	73,281	62,336	**39,208**	42,213	44,215	46,313	48,513
Industry associations	62,400	60,000	60,000	**60,000**	60,600	61,206	61,818	62,436
Regulatory fees and costs	205,564	191,400	126,661	**269,641**	238,847	240,412	241,482	242,567
Bad debts- BGI Impairment	-	-	127,869	**96,810**	94,096	85,458	86,553	86,886
Corp - IT/Prj Mgr	-	-	17,321	**178,156**	291,829	303,895	316,824	330,355
	2,072,742	2,072,554	2,381,737	**2,913,745**	2,779,039	2,717,170	2,792,087	2,846,891
OTHER DIRECT COSTS	-							
Special projects	344,865	1,071,941	646,236	**961,167**	1,203,730	1,265,360	923,897	855,031
	344,865	1,071,941	646,236	**961,167**	1,203,730	1,265,360	923,897	855,031
	-							
TOTAL DIRECT EXPENSES	$ 8,872,070	$ 9,835,517	$ 9,260,857	**$ 11,038,339**	$ 11,058,407	$ 11,171,094	$ 11,055,594	$ 11,141,299

BRANTFORD POWER INC.
2016 BUDGET AND MULTI-YEAR FORECAST
SCHEDULE OF OPERATIONS, MAINTENANCE AND ADMINISTRATIVE EXPENSES NET OF ALLOCATIONS

	2014 Actual	2015 Budget	2015 Projected	2016 Budget	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast
INDIRECT GENERAL AND ADMINISTRATIVE EXPENSES								
OPERATIONS, MAINTENANCE AND ADMINISTRATION								
Retiree benefits	$ 44,506	$ 90,577	$ 83,765	**$ 160,916**	$ 160,701	$ 182,049	$ 180,777	$ 178,043
Records management, mail, telephone & duplicating	12,925	12,815	14,511	**13,828**	14,104	14,387	14,675	14,969
Insurance and risk management	97,926	104,602	86,000	**82,522**	84,172	85,855	87,572	89,323
Property charges	-	-	-	**118,939**	485,273	494,978	504,878	514,975
Legal	15,622	15,000	13,600	**12,190**	12,434	12,683	12,937	13,196
Brantford Energy Corp Management Fees	125,308	124,190	148,775	**103,357**	104,532	98,745	99,088	99,734
Other	72,825	24,480	22,988	**23,000**	22,500	22,000	21,500	21,000
TOTAL INDIRECT EXPENSES	$ 369,112	$ 371,664	$ 369,639	**$ 514,752**	$ 883,716	$ 910,697	$ 921,427	$ 931,240
	-							
TOTAL OPERATIONS, MAINTENANCE AND ADMINISTRATIVE EXPENSES	$ 9,241,182	$ 10,207,181	$ 9,630,496	**$ 11,553,091**	$ 11,942,122	$ 12,081,791	$ 11,977,021	$ 12,072,539
	-							
INDIRECT COSTS ALLOCATED	-							
To direct distribution operations and maintenance	$ 722,856	$ 954,805	$ 741,233	**$ 956,402**	$ 773,549	$ 806,342	$ 856,313	$ 870,663
To direct general and administration	307,523	329,385	336,501	**400,806**	256,444	261,577	266,805	272,141
To direct billing and collecting (customer service)	349,937	360,932	323,173	**400,818**	324,642	331,129	337,758	344,513
To OPA Conservation and Demand Management	24,752	24,300	24,835	**27,281**	19,211	19,595	19,987	20,387
	$ 1,405,069	$ 1,405,069	$ 1,425,742	**$ 1,785,307**	$ 1,373,846	$ 1,418,643	$ 1,480,863	$ 1,507,704
To recoverable	(448,991)	(370,148)	(364,351)	**(383,159)**	(409,282)	(412,336)	(419,094)	(424,601)
To capital	-	-	-	**-**	-	-	-	-
	$ (448,991)	$ (370,148)	$ (364,351)	**$ (383,159)**	$ (409,282)	$ (412,336)	$ (419,094)	$ (424,601)
NET INDIRECT COSTS ALLOCATED TO DIRECTS	$ 956,078	$ 1,034,921	$ 1,061,391	**$ 1,402,148**	$ 964,564	$ 1,006,307	$ 1,061,769	$ 1,083,103

BRANTFORD POWER INC.
2016 BUDGET AND MULTI-YEAR FORECAST
SCHEDULE OF DIRECT AND INDIRECT EXPENSES BEFORE ALLOCATIONS

	2014 Actual	2015 Budget	2015 Projected	2016 Budget	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast
DIRECT EXPENSES								
DISTRIBUTION OPERATIONS AND MAINTENANCE								
Distribution operations and maintenance	$ 2,830,357	$ 2,561,789	$ 2,598,010	**$ 2,905,810**	$ 3,083,538	$ 3,129,057	$ 3,185,791	$ 3,237,446
Engineering operations and maintenance	845,074	916,218	834,032	**829,068**	844,306	871,989	888,662	900,943
Settlement	801,783	844,298	878,196	**1,384,822**	1,411,453	1,439,197	1,463,039	1,480,196
Engineering Services	320,062	400,000	326,300	**337,587**	344,339	351,226	358,251	365,416
Transformer Station operations and maintenance	99,673	113,728	98,197	**104,595**	103,919	105,325	105,552	105,792
	4,896,950	4,836,033	4,734,735	**5,561,882**	5,787,555	5,896,794	6,001,295	6,089,793
BILLING AND COLLECTING								
Customer Services	1,475,967	1,524,224	1,611,070	**1,261,656**	1,328,795	1,325,215	1,356,506	1,375,370
LEAP Program	20,407	21,000	21,000	**21,000**	25,000	25,000	25,000	25,000
Bad debts	366,783	306,000	123,647	**300,000**	300,000	300,000	300,000	300,000
	1,863,156	1,851,224	1,755,717	**1,582,656**	1,653,795	1,650,215	1,681,506	1,700,370
DIRECT GENERAL AND ADMINISTRATIVE								
Board of Directors	40,404	54,250	34,559	**34,559**	34,645	34,731	34,818	34,906
Senior Leadership Team	865,096	891,582	1,121,484	**1,082,604**	1,119,192	1,113,220	1,144,035	1,152,295
Finance	421,482	419,352	429,652	**478,505**	558,235	461,801	470,781	481,577
Corporate Services and Regulatory Affairs	227,403	323,717	306,247	**534,909**	334,447	348,098	362,396	377,342
Corporate communications	60,398	73,281	62,336	**39,208**	42,213	44,215	46,313	48,513
Industry associations	62,400	60,000	60,000	**60,000**	60,600	61,206	61,818	62,436
Regulatory fees and costs	205,564	191,400	126,661	**269,641**	238,847	240,412	241,482	242,567
Bad debts- BGI Impairment	-	-	127,869	**96,810**	94,096	85,458	86,553	86,886
Corp - IT/Prj Mgr	-	-	17,321	**278,870**	291,829	303,895	316,824	330,355
	1,882,747	2,013,582	2,286,128	**2,875,107**	2,774,104	2,693,036	2,765,020	2,816,877
OTHER DIRECT COSTS								
Special projects	344,865	1,071,941	646,236	**961,167**	1,203,730	1,265,360	923,897	855,031
	344,865	1,071,941	646,236	**961,167**	1,203,730	1,265,360	923,897	855,031
TOTAL DIRECT EXPENSES	$ 8,987,717	$ 9,772,780	$ 9,422,816	**$ 10,980,812**	$ 11,419,184	$ 11,505,405	$ 11,371,718	$ 11,462,071

BRANTFORD POWER INC.
2016 BUDGET AND MULTI-YEAR FORECAST
SCHEDULE OF DIRECT AND INDIRECT EXPENSES BEFORE ALLOCATIONS

	2014 Actual	2015 Budget	2015 Projected	2016 Budget	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast
INDIRECT EXPENSES								
INDIRECT GENERAL AND ADMINISTRATIVE EXPENSES								
Retiree benefits	$ 44,506	$ 90,577	$ 83,765	**$ 160,916**	$ 160,701	$ 182,049	$ 180,777	$ 178,043
Records management, mail, telephone & duplicating	20,969	21,395	21,800	**22,408**	22,856	23,314	23,781	24,257
Insurance and risk management	108,391	115,822	86,000	**82,522**	84,172	85,855	87,572	89,323
Treasury and accounting	72,849	70,686	79,200	**87,039**	-	-	-	-
Purchasing and dispatch	102,625	90,939	179,814	**180,455**	183,380	185,041	188,372	191,619
Management information systems	741,961	862,816	747,100	**898,448**	916,417	934,745	953,440	972,509
Property charges	498,536	498,061	510,200	**696,063**	751,669	766,702	782,036	797,677
Legal	15,622	15,000	13,600	**12,190**	12,434	12,683	12,937	13,196
Human resources	114,533	99,738	69,500	**66,905**	68,243	69,608	71,000	72,420
Minor capital improvements	-	30,000	-	**-**	-	-	-	-
Brantford Energy Corp Management Fees	125,308	124,190	148,775	**103,357**	104,532	98,745	99,088	99,734
Other	72,825	24,480	22,988	**23,000**	22,500	22,000	21,500	21,000
Fleet recovery	(139,433)	(2,618)	(61,728)	**(24,567)**	(46,217)	(27,814)	5,846	3,707
	1,778,693	2,041,086	1,901,014	**2,308,736**	2,280,687	2,352,928	2,426,349	2,463,485
GRAND TOTAL OPERATIONS, MAINTENANCE AND ADMINISTRATIVE EXPENSES	$ 10,766,410	$ 11,813,866	$ 11,323,830	**$ 13,289,548**	$ 13,699,871	$ 13,858,333	$ 13,798,067	$ 13,925,556

BRANTFORD POWER INC.
2016 BUDGET AND MULTI-YEAR FORECAST
SCHEDULE OF DIRECT AND INDIRECT EXPENSES - DETAIL

	2015 Budget	2015 Projected	2016 Budget	Direct Salaries, Wages & Benefits	Direct Goods & Services	City SLA	Total Gross Direct & Indirect Costs	Allocation of Indirect Costs to Operational Accounts	Fully Allocated Direct & Indirect Costs	Allocation to CDM, Affiliate, Capital or Billable Projects	Net Direct and Indirect Costs
DISTRIBUTION OPERATIONS AND MAINTENANCE											
Distribution operations and maintenance	$ 2,088,772	$ 1,697,955	**$ 2,067,331**	1,818,284	1,087,526	-	**$ 2,905,810**	301,566	**$ 3,207,376**	(1,140,045)	**$ 2,067,331**
Engineering operations and maintenance	979,235	957,358	**1,057,009**	609,514	219,554	-	**829,068**	461,724	**1,290,792**	(233,783)	**1,057,009**
Settlement	926,137	1,027,611	**1,540,928**	582,110	802,712	-	**1,384,822**	157,343	**1,542,165**	(1,237)	**1,540,928**
Engineering Services	400,000	342,731	**357,428**	-	-	337,587	**337,587**	19,841	**357,428**	-	**357,428**
Transformer Station operations and maintenance	113,728	98,197	**104,595**	6,470	90,825	7,300	**104,595**	-	**104,595**	-	**104,595**
	4,507,872	4,123,853	**5,127,291**	3,016,378	2,200,617	344,887	**5,561,882**	940,474	**6,502,356**	(1,375,065)	**5,127,291**
BILLING AND COLLECTING											
Customer Services	1,856,150	1,964,385	**1,715,136**	948,733	312,923	-	**1,261,656**	453,480	**1,715,136**	-	**1,715,136**
LEAP Program	21,000	21,000	**21,000**	-	21,000	-	**21,000**	-	**21,000**	-	**21,000**
Bad debts	306,000	123,647	**300,000**	-	300,000	-	**300,000**	-	**300,000**	-	**300,000**
	2,183,150	2,109,032	**2,036,136**	948,733	633,923	-	**1,582,656**	453,480	**2,036,136**	-	**2,036,136**
DIRECT GENERAL AND ADMINISTRATIVE											
Board of Directors	79,650	43,526	**39,088**	15,959	18,600	-	**34,559**	4,529	**39,088**	-	**39,088**
Senior Leadership Team	735,046	981,275	**982,785**	850,118	232,486	-	**1,082,604**	118,702	**1,201,306**	(218,521)	**982,785**
Finance	461,847	549,375	**634,716**	361,681	116,825	-	**478,505**	171,087	**649,592**	(14,876)	**634,716**
Corporate Services and Regulatory Affairs	471,330	413,375	**613,340**	285,230	249,679	-	**534,909**	78,431	**613,340**	-	**613,340**
Corporate communications	73,281	62,336	**39,208**	37,608	1,600	-	**39,208**	-	**39,208**	-	**39,208**
Industry associations	60,000	60,000	**60,000**	-	60,000	-	**60,000**	-	**60,000**	-	**60,000**
Regulatory fees and costs	191,400	126,661	**269,641**	-	269,641	-	**269,641**	-	**269,641**	-	**269,641**
Bad debts- BGI Impairment	-	127,869	**96,810**	-	96,810	-	**96,810**	-	**96,810**	-	**96,810**
Corp - IT/Prj Mgr	-	17,321	**178,156**	257,194	21,676	-	**278,870**	-	**278,870**	(100,714)	**178,156**
	2,072,554	2,381,737	**2,913,745**	1,807,790	1,067,317	-	**2,875,107**	372,749	**3,247,856**	(334,111)	**2,913,745**
OTHER DIRECT COSTS											
Special projects	1,071,941	646,236	**961,167**	201,797	759,370	-	**961,167**	-	**961,167**	-	**961,167**
	1,071,941	646,236	**961,167**	201,797	759,370	-	**961,167**	-	**961,167**	-	**961,167**
TOTAL DIRECT EXPENSES	$ 9,835,517	$ 9,260,857	**$ 11,038,339**	$ 5,974,698	$ 4,661,227	$ 344,887	**$ 10,980,812**	$ 1,766,703	**$ 12,747,515**	$(1,709,176)	**11,038,339**

BRANTFORD POWER INC.
2016 BUDGET AND MULTI-YEAR FORECAST
SCHEDULE OF DIRECT AND INDIRECT EXPENSES - DETAIL

	2015 Budget	2015 Projected	2016 Budget	Direct Salaries, Wages & Benefits	Direct Goods & Services	City SLA	Total Gross Direct & Indirect Costs	Allocation of Indirect Costs to Operational Accounts	Fully Allocated Direct & Indirect Costs	Allocation to CDM, Affiliate, Capital or Billable Projects	Net Direct and Indirect Costs
INDIRECT GENERAL AND ADMINISTRATIVE EXPENSES											
Retiree benefits	$ 90,577	$ 83,765	**$ 160,916**	-	85,200	75,716	**$ 160,916**	-	**160,916**	-	**$ 160,916**
Records management, mail, telephone & duplicating	12,815	14,511	**13,828**	-	-	22,408	**22,408**	(8,580)	**13,828**	-	**13,828**
Insurance and risk management	104,602	86,000	**82,522**	-	-	82,522	**82,522**	-	**82,522**	-	**82,522**
Treasury and accounting	-	-	**-**	-	-	87,039	**87,039**	(87,039)	**-**	-	**-**
Purchasing and dispatch	-	-	**-**	172,435	8,020	-	**180,455**	(180,455)	**-**	-	**-**
Management information systems	-	-	**-**	-	-	898,448	**898,448**	(898,448)	**-**	-	**-**
Property charges	-	-	**118,939**	-	-	696,063	**696,063**	(577,124)	**118,939**	-	**118,939**
Legal	15,000	13,600	**12,190**	-	-	12,190	**12,190**	-	**12,190**	-	**12,190**
Human resources	-	-	**-**	-	-	66,905	**66,905**	(66,905)	**-**	-	**-**
Brantford Energy Corp Management Fees	124,190	148,775	**103,357**	-	103,357	-	**103,357**	-	**103,357**	-	**103,357**
Other	24,480	22,988	**23,000**	-	23,000	-	**23,000**	-	**23,000**	-	**23,000**
Fleet recovery	-	0	**-**	61,110	(265,748)	180,071	**(24,567)**	24,567	**-**	-	**-**
TOTAL INDIRECT EXPENSES	$ 371,664	$ 369,639	**$ 514,752**	$ 233,545	$ (46,171)	$ 2,121,362	**$ 2,308,736**	$(1,793,984)	**$ 514,752**	$ -	**$ 514,752**
CDM ADMINISTRATIVE EXPENSES							**$ -**	$ 27,281	**$ 27,281**	**$ (27,281)**	**$ -**
GRAND TOTAL OM&A EXPENSES	$ 10,207,181	$ 9,630,496	**$ 11,553,091**	$ 6,208,243	$ 4,615,056	$ 2,466,249	**$ 13,289,548**	$ -	**$ 13,262,267**	$(1,709,176)	**$ 11,553,091**
Transfer to billable/recoverable projects	$ 370,148	$ 364,351	**$ -**	$ -	$ -	$ -	**$ -**	$ -	**$ -**	$ 383,159	
Transfer to capital projects	-	-	**-**	-	-	-	**-**	-	**-**	1,092,620	
Transfer to OPA CDM Programs	24,300	24,835	**-**	-	-	-	**-**	-	**-**		
Transfer to affiliate - BEC							**-**			46,486	
Transfer to affiliate - BHI							**-**			115,625	
Transfer to affiliate - BGI										71,286	
	394,448	389,186	**-**	-	-	-	**-**	-	**-**	1,709,176	
NET TOTAL OM&A EXPENSES	$ 10,601,629	$ 10,019,682	**$ 11,553,091**	$ 6,208,243	$ 4,615,056	$ 2,466,249	**$ 13,289,548**	$ -	**$ 13,262,267**	$ -	**$ 11,553,091**

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BRANTFORD POWER INC.
2016 BUDGET AND MULTI-YEAR FORECAST
SCHEDULE OF REGULATORY ASSETS AND LIABILITIES

	2014 Actual	2015 Budget	2015 Projected	2016 Budget	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast
SUMMARY BY MAJOR REGULATORY ACCOUNT CATEGORY								
RETAIL SETTLEMENT VARIANCE ACCOUNTS								
Wholesale Market Service Charges	$ (988,870)	$ (1,047,843)	$ (1,253,431)	**$ (1,559,311)**	$ (922,812)	$ (909,441)	$ (905,614)	$ (906,727)
Transmission - Network	874,193	1,983,395	553,574	**266,980**	696,848	695,156	695,717	698,201
Transmission - Connection	73,446	414,967	211,228	**130,942**	94,991	93,604	93,597	93,933
Cost of Power	(2,821,457)	(2,148,006)	(2,796,606)	**(2,118,063)**	(1,257,723)	(1,297,884)	(1,353,720)	(1,388,760)
Global Adjustment	3,034,422	537,604	3,101,929	**2,521,031**	2,025,581	2,083,567	2,165,856	2,237,580
One Time	290,236	293,341	292,755	**295,078**	-	-	-	-
	461,970	33,458	109,449	**(463,343)**	636,885	665,002	695,836	734,227
OTHER DEFERRAL AND VARIANCE ACCOUNTS								
Stranded Meters	2,332,050	1,629,564	1,626,662	**867,832**	93,770	93,980	94,189	94,399
Smart Meter Entity Charge	24,327	(6,200)	(7,340)	**(4,033)**	(1,968)	(1,759)	(803)	1
	2,356,376	1,623,364	1,619,322	**863,799**	91,802	92,221	93,386	94,400
General								
CDM Lost Revenue	114,639	122,683	18,920	**80,792**	62,346	376,557	740,742	1,164,226
Embedded LDC Revenue Difference	171,716	174,076	173,631	**175,397**	-	-	-	-
Retailer Cost Variance Account	48,103	73,800	74,719	**93,478**	36,240	54,796	73,634	92,759
IFRS transition costs and early disposals	253,997	272,696	301,825	**344,518**	-	-	-	-
Recovery of regulatory assets	(90,863)	(94,347)	(278,526)	**(303,860)**	(258,868)	(15,184)	10,743	19,593
	497,593	548,908	290,569	**390,325**	(160,282)	416,169	825,119	1,276,578
Other								
Regulatory future income tax liability	664,215	(1,829,896)	1,351,605	**1,777,974**	2,371,334	2,731,722	3,033,482	3,316,437
Other regulatory assets	277	19,248	277	**277**	-	-	-	-
	664,492	(1,810,648)	1,351,882	**1,778,251**	2,371,334	2,731,722	3,033,482	3,316,437
Total	3,980,431	395,082	3,371,222	**2,569,032**	2,939,739	3,905,114	4,647,823	5,421,642
Summary								
Total Regulatory Assets	6,643,746	5,521,374	7,707,125	**6,554,299**	5,541,392	6,129,382	6,907,960	7,717,129
Total Regulatory Liabilities	(2,663,315)	(5,126,292)	(4,335,903)	**(3,985,267)**	(2,601,653)	(2,224,268)	(2,260,137)	(2,295,487)
Net Assets(Liabilities)	$ 3,980,431	$ 395,082	$ 3,371,222	**$ 2,569,032**	$ 2,939,739	$ 3,905,114	$ 4,647,823	$ 5,421,642
Group 1	195,510	(231,547)	(442,912)	**(981,489)**	440,363	1,026,375	1,447,321	1,918,046
Group 2	3,120,706	2,456,525	2,462,529	**1,772,547**	128,042	147,017	167,020	187,159
Group 3	664,215	(1,829,896)	1,351,605	**1,777,974**	2,371,334	2,731,722	3,033,482	3,316,437
Net Assets(Liabilities)	$ 3,980,431	$ 395,082	$ 3,371,222	**$ 2,569,032**	$ 2,939,739	$ 3,905,114	$ 4,647,823	$ 5,421,642

BRANTFORD POWER INC.
2016 BUDGET AND MULTI-YEAR FORECAST
RATIOS AND LOAD AND CUSTOMER STATISTICS

	2014 Actual	2015 Budget	2015 Projected	2016 Budget	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast
Current Ratio (OILC not less than 1.1:1)	1.9	2.3	2.0	**1.9**	2.0	2.0	2.1	2.1
Quick Ratio	0.6	0.7	0.6	**0.4**	0.5	0.4	0.6	0.5
Working Capital	15,894,599	19,210,183	17,405,719	**14,885,607**	18,198,727	17,103,805	20,184,411	19,913,102
Debt to Equity (OILC <60%)	52.1%	51.9%	50.3%	**56.9%**	58.1%	57.2%	58.2%	56.9%
Debt to Equity (RBC <60% exclude City Note)	32.3%	32.7%	30.1%	**42.4%**	44.9%	43.5%	45.6%	43.8%
Debt to Equity (Regulatory)	52.1%	51.9%	50.3%	**56.9%**	58.1%	57.2%	58.2%	56.9%
Dividend Payout Ratio (Regular and Special)	29.1%	56.9%	38.9%	**103.2%**	57.4%	58.2%	49.6%	40.9%
Return on Equity	6.6%	3.3%	6.3%	**2.5%**	3.4%	3.3%	3.8%	4.5%
Return on Regulatory Equity	6.6%	3.3%	6.3%	**2.5%**	3.4%	3.3%	3.8%	4.5%
Return on Assets	2.4%	1.2%	2.4%	**0.9%**	1.1%	1.1%	1.3%	1.5%
Debt Service Coverage (OILC no less than 1.2:1)	3.45	1.41	1.93	**(0.62)**	1.44	1.58	(7.33)	1.76
OM&A Cost per Customer	$ 237.10	$ 258.14	$ 243.50	**$ 289.69**	$ 297.19	$ 298.39	$ 293.57	$ 293.68
Distribution Revenue per Customer	$ 412.19	$ 413.05	$ 413.46	**$ 417.96**	$ 455.95	$ 460.14	$ 466.78	$ 473.84
Rate Base Growth	-	3.3%	2.1%	**12.4%**	12.3%	2.0%	1.7%	1.1%
STAFFING LEVELS (FULL TIME EQUIVALENT)								
Senior Leadership Team	5.67	5.00	5.00	**5.00**	5.00	5.00	5.00	5.00
Corporate Services	-	-	0.13	**2.00**	2.00	2.00	2.00	2.00
Customer Service	13.74	14.58	15.33	**12.92**	13.92	15.42	13.42	12.42
Engineering	8.00	8.00	8.67	**9.00**	9.00	9.00	9.00	9.00
Finance	3.67	5.50	4.54	**6.50**	7.00	5.00	5.00	5.00
Operations	17.24	17.00	17.67	**18.50**	19.00	19.00	19.00	19.00
Regulatory	2.00	3.00	2.38	**3.00**	3.00	3.00	3.00	3.00
Communications	0.70	1.00	0.69	**0.69**	0.69	0.69	0.69	0.69
Settlement	5.00	5.00	3.33	**5.00**	5.00	5.00	5.00	5.00
	56.01	59.08	57.73	**62.61**	64.61	64.11	62.11	61.11
Conservation and Demand Management	2.00	2.00	1.63	**3.00**	3.00	3.00	3.00	3.00
	58.01	61.08	59.35	**65.61**	67.61	67.11	65.11	64.11
Full Time	54.28	55.00	54.00	**58.25**	59.00	59.00	59.00	59.00
Part-Time	1.41	1.42	1.42	**1.42**	1.42	1.42	1.42	1.42
Contract	2.32	4.66	3.93	**5.94**	7.19	6.69	4.69	3.69
	58.01	61.08	59.35	**65.61**	67.61	67.11	65.11	64.11

BRANTFORD POWER INC.
2016 BUDGET AND MULTI-YEAR FORECAST
RATIOS AND LOAD AND CUSTOMER STATISTICS

	2014 Actual	2015 Budget	2015 Projected	2016 Budget	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast
ENERGY SOLD (Mwh)								
Residential	284,160	287,739	289,767	**289,643**	291,579	293,256	294,963	296,725
General Service < 50 KW	100,424	103,236	103,769	**104,467**	104,862	105,149	105,458	105,790
General Service > 50 KW (includes Back-up/Standby)	537,759	494,508	504,978	**494,432**	485,490	478,599	478,939	479,221
Street lighting	7,430	7,396	7,175	**7,342**	7,342	7,342	7,342	7,342
Sentinel lighting	451	420	434	**433**	423	412	401	390
Unmetered Scattered Load	1,561	1,503	1,517	**1,506**	1,491	1,480	1,470	1,460
	931,785	894,802	907,640	**897,823**	891,187	886,238	888,573	890,928
ENERGY PURCHASED (Mwh)								
Independent Electricity Systems Operator & Others	961,319	921,646	934,869	**924,758**	917,923	912,825	915,230	917,656
LINE LOSSES/UNACCOUNTED FOR ENERGY	(29,534)	(26,844)	(27,229)	**(26,935)**	(26,736)	(26,587)	(26,657)	(26,728)
LINE LOSSES/UNACCOUNTED FOR ENERGY %	(3.0%)	(3.0%)	(3.0%)	**(3.0%)**	(3.0%)	(3.0%)	(3.0%)	(3.0%)
DEMAND (KW's)								
General Service > 50 KW	1,568,023	1,443,544	1,516,664	**1,465,784**	1,405,361	1,389,482	1,391,516	1,393,664
Street lighting	22,581	22,520	21,902	**21,930**	21,930	21,930	21,930	21,930
	1,590,604	1,466,064	1,538,566	**1,487,714**	1,427,291	1,411,412	1,413,446	1,415,594
CUSTOMER COUNT								
Residential	35,351	35,886	35,884	**36,195**	36,476	36,760	37,045	37,333
General Service < 50 KW	2,760	2,794	2,799	**2,819**	2,838	2,858	2,878	2,897
General Service > 50 KW (includes Back-up/Standby)	430	437	438	**443**	449	454	459	465
Unmetered Scattered Load	435	424	429	**424**	421	418	415	412
	38,976	39,541	39,550	**39,881**	40,184	40,489	40,797	41,107
CONNECTIONS								
Street lighting	10,075	10,080	10,080	**10,080**	10,080	10,080	10,080	10,080
Sentinel lighting	623	588	621	**614**	598	582	567	552
	10,698	10,668	10,701	**10,694**	10,678	10,662	10,647	10,632
CUSTOMER COUNT BY SUPPLY OPTION								
Distributor - Regulated Price Plan	35,715	36,117	36,481	**36,785**	37,063	37,342	37,626	37,910
Distributor - Market Price	255	239	254	**257**	260	263	266	269
Retailer - Distributor Consolidated Billing	3,006	3,185	2,815	**2,839**	2,861	2,884	2,905	2,928
Retailer - Retailer Consolidated Billing	-	-	-	**-**	-	-	-	-
	38,976	39,541	39,550	**39,881**	40,184	40,489	40,797	41,107
ENERGY GENERATORS								
BCPI Load Transfer	1	1	1	**1**	1	1	1	1
Embedded Generator	1	1	1	**1**	1	1	1	1
RESOP	1	1	1	**1**	1	1	1	1
Fit/Microfit	106	125	125	**140**	155	170	185	200
	109	128	128	**143**	158	173	188	203

Attachment 1-SEC-2-C: BPI Budget Resolution Board of Directors

Whereas the Board of Directors have reviewed the proposed 2016 Budget and Multi year forecast presented by Management; and

Whereas Brantford Power Inc. has achieved strong returns in 2013 and 2014 and is currently forecasting a strong return in 2015; and

Whereas the proposed budget for 2016 reflects distribution revenues that continue to be based on a revenue requirement established pursuant to the 2013 costs of service distribution rate application process , and

Whereas this revenue requirement does not reflect adequate funding for transitional and new ongoing costs related to the implementation of certain Brantford Power Inc. strategic plan initiatives including the elimination of three operating facilities by the acquisition of an existing repurposed consolidated facility and the implementation of a new financial information systems, and

Whereas , the financial impact of these unfunded costs is a budgeted 2016 return that is significantly below the level of returns contemplated in the 2013 Cost of Service rate application and further that the current illustration of future 2017-2020 returns continue to reflect returns that are consistently below the 9.19% return on equity level currently identified by the OEB as the reasonable return on equity;

That the Brantford Power Inc. Board of Directors approve the 2016 Budget as submitted and direct Management to incorporate into the 2017 Cost of Service Distribution Rate application a revenue requirement request that is sufficient to re cover Brantford Power Inc.’s prudently incurred cost of service necessary to achieve a reasonable return on equity at the level established by the Ontario Energy Board.

Attachment 1-SEC-4-B: 2016 MEARIE Survey

The MEARIE Group

2014 Management Salary Survey
Of Local Distribution Companies

SURVEY REPORT

August 2014

SURVEY ADMINISTRATOR: HAY GROUP LIMITED

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Section

Appendices

1. Introduction

The MEARIE Group is pleased to present this report of the 2014 Management Salary Survey of Local Distribution Companies (LDCs).

In today's competitive talent market, LDCs are challenged with establishing and maintaining competitive, yet affordable, compensation programs and policies. The MEARIE Group established the Management Salary Survey of Ontario's Local Distribution Companies to assist LDCs in understanding the competitive landscape and to support your efforts to develop pay practices that attract, motivate and retain high quality, high performing employees.

The survey was updated in 2012 through the combined efforts of The MEARIE Group's *HR Information Solutions* team, outside consultants and representatives of our members, all working together to ensure that the Survey continues to meet the evolving needs of member LDCs.

The Survey was further enhanced in 2013 & 2014 through our partnership with Hay Group, a globally renowned compensation consulting firm. Drawing on their expertise and experience in developing and managing salary surveys across all sectors of the economy and in numerous countries around the world.

The 2014 survey includes:

- Geographic, Number of Employees, Number of Customer and Revenue size reporting.
- Fifty (50) benchmark descriptions, supported by the Hay Group job evaluation methodology for improved reporting and greater ability to identify the impact of organization size and structure.
- Continued reporting of "total cash compensation" to provide greater depth of information regarding market pay practices.
- An overview of local distribution company market trends and compensation projections for 2015 budget planning.
- MS Excel survey reporting including versions of position salary tables by All Organizations, Geography, Revenue and Customers to support those organizations that wish to conduct further analysis of the results and to assist in transferring survey results into internal reporting.

The survey includes two presentation documents and Excel data tables in formats as follows:

- PDF Documents:
  - Survey Report Executive Summary containing a complete analysis and a data summary of all the positions.
  - Survey Report addendum which includes a complete analysis of each position, presented on one page.
- Excel Documents which are provided for easy data export and printable to one legal sized page, showing LDC Survey data by:
  - All Organizations
  - Region
  - Customer Base
  - Revenue
  - Number of Employees

We would like to thank you for your participation. As a result of the strong response, we are able to provide you with an informative and detailed survey that will help you in the support of your organization's compensation programs.

CONFIDENTIALITY POLICY

The MEARIE Group recognizes the importance of maintaining the security of your information and has developed the following policy that applies to all participants (and their delegates) in the Management Salary Survey (a "Survey"), as well as Hay Group Limited (Hay Group) (survey administrators) and The MEARIE Group.

An individual LDC will provide its authorization for the sharing of information identified as being information of that LDC by completing the Survey Data Submission for a Survey. This will result in the LDC's data being identified by name in the listing of participants. This enables participants to be aware of the names of the other participants in the Survey to determine the relevance of Survey data cuts (e.g., by geography or size).

All of the information obtained through a Survey will be treated with the utmost confidentiality. Data will be reported on an aggregate basis only, and in such a way as to ensure that individual participant data cannot be identified/attributed. Standards for minimum number of data will be strictly enforced to ensure confidentiality. Neither Hay Group nor MEARIE Group will release or disclose to any other person whatsoever any information pertaining to any individual LDC participant.

Survey results will be reported only to those LDCs who participate in the Survey and provide comprehensive data. Comprehensive participation means that each LDC is expected to match as many of the Survey benchmark positions as they are able, and provide data for all incumbents of matched positions. **All participants must consider this information as strictly confidential.**

The results of a Survey will not be disclosed/sold to or shared with organizations that have not participated in that Survey, whether by The MEARIE Group or Hay Group or Survey participants. **Participants may not share the Survey reports/results with non-participant LDCs or any entity under any circumstances.**

The data collected for a Survey will also be included in the Hay Group's Canadian compensation database. Information in the Hay Group database is maintained with the highest standards of confidentiality; analysis and reporting of data is on an aggregate basis only, and in such a way as to ensure that individual participant data cannot be identified or attributed. As of January 2014, there are over 550 employers represented in the Hay Group database. Should you have any questions or for further information, please contact Deirdre Chong Smith, Consultant at Hay Group at 416-815-6344 or Deirdre.Chong@haygroup.com.

The obligations of confidentiality set out in this policy are subject to the requirements of applicable law and LDCs may disclose the results of the Survey to any regulatory body (or other person) if compelled by law to do so. If an LDC is compelled by law to make such a disclosure, it will give The MEARIE Group as much notice in advance as possible of the disclosure and the reasons the disclosure is legally required.

The MEARIE Group will not be liable for breaches by participating LDCs or Hay Group of this Confidentiality Policy.

2. Survey Overview

Survey Benchmark Positions

The survey covers 50 benchmark positions representing a cross-section of the functions within member organizations. The benchmark positions were reviewed in 2012 by a working group of LDC sector Human Resources professionals. Job profiles for each benchmark job were developed and reviewed by the consultants and the HR group.

Senior Management	0000	President & CEO
	0001	Chief Operating Officer (COO)
	0002	Head of Operations and/or Engineering
	0003	CFO / Head of Finance
	0004	Head of Customer Service
	0005	Head of Regulatory Affairs
	0006	Head of Human Resources
Administration	1000	Executive Assistant
	1001	Administrative Assistant
Engineering	2000	Director Engineering
	2001	Engineering Manager and/or Distribution Engineer
	2002	Project Engineer
	2003	Supervisor Engineering
Operations	2500	Director Operations
	2501	Manager Operations
	2502	Manager Control Centre
	2503	Supervisor Control Centre
	2504	Supervisor Protection and Control
	2505	Supervisor Station Maintenance
	2506	Line Supervisor
	2507	Manager Meter Department
	2508	Supervisor Meter Department

Supply Chain / Procurement	3000	Director Supply Chain Management
	3001	Manager Procurement and/or Inventory and/or Facilities and/or Fleet
	3002	Supervisor Stores / Inventory / Warehouse
Accounting / Finance	4000	Controller or Director Finance
	4001	Manager Accounting
	4002	Manager Risk Management
	4003	Supervisor Accounting
	4004	Financial or Business Analyst
	4005	Accountant
Customer Service	5000	Director Customer Service
	5001	Manager Customer Service and/or Billing
	5002	Supervisor Customer Service and/or Billing and/or Collections
Communications	5500	Director Communications
	5501	Manager Communications
Regulatory Affairs	6000	Director Regulatory Affairs
	6001	Manager Regulatory Affairs
	6002	Regulatory Accountant
Conservation / Demand	7000	Settlement or Rate Analyst
	7001	Director or Officer, Conservation and Demand Management
	7002	Manager Conservation & Demand / Marketing
Information Systems	8000	Director Information Systems
	8001	Manager Information Systems and/or Security
	8002	Systems / Program Administrator or Applications / Systems Support Professional
Human Resources	9000	Human Resources Manager
	9001	Human Resources Generalist
	9002	Human Resources Coordinator
	9003	Payroll
	9004	Manager, Health & Safety

Participants

All organizations in the LDC sector in Ontario were invited to participate in the survey. The following forty-five (45) organizations submitted data:

- Bluewater Power Distribution Corporation
- Brantford Power Inc.
- Cambridge and North Dumfries Hydro Inc.
- Collus PowerStream Corp.
- E.L.K. Energy Inc.
- Enersource Corporation
- Entegrus Inc.
- Essex Power
- Festival Hydro Inc.
- Fort Frances Power Corporation
- Greater Sudbury Utilities
- Grimsby Power Incorporated
- Guelph Hydro Electric Systems Inc.
- Haldimand County Hydro Inc.
- Halton Hills Hydro Inc.
- Horizon Utilities Corporation
- Hydro Ottawa Limited
- Innisfil Hydro Distribution Systems Limited
- Kenora Hydro Electric Corporation Ltd.
- Kitchener-Wilmot Hydro Inc.
- Lakeland Holding Ltd.
- London Hydro Inc.
- Midland Power Utility Corporation
- Milton Hydro Distribution Inc.
- Niagara Peninsula Energy Inc.
- North Bay Hydro Distribution Limited
- Northern Ontario Wires Inc.
- Oakville Hydro
- Orangeville Hydro Limited
- Orillia Power Distribution Corporation
- Oshawa PUC Networks, Inc.
- Ottawa River Power Corporation
- Peterborough Utilities Group
- PowerStream Inc.
- PUC Services Inc.
- Renfrew Hydro Inc.
- Sioux Lookout Hydro Inc.
- Thunder Bay Hydro Electricity Distribution Inc.
- Utilities Kingston / Kingston Hydro
- Veridian Connections Inc.
- Wasaga Resource Services
- Waterloo North Hydro Inc.
- Welland Hydro-Electric System Corp.
- Westario Power Inc.
- Woodstock Hydro Services Inc.

Participant Group Profile

All participants provided information regarding their organizational profile. The statistical references for the profile of the organizations are as follows:

Note that the figures reported below are as provided by the participating organizations. Hay Group and MEARIE Group have not independently verified or confirmed the values, especially with regard to whether the values reflect only the LDC business or include other business ventures.

Statistic	P25	P50	P75	Average *
Annual Operating Budget ($ millions, less the cost of power)	4.5	10.9	18.0	17.9
Annual Operating Budget ($ millions, including the cost of power)	30.9	61.7	143.3	148.8
Number of Employees (full time equivalent)	33	51	128	111
Number of Customers	12,800	31,485	52,607	56,887
Gross Revenue ($ millions, less the cost of power)	5.7	14.6	33.2	32.8
Gross Revenue ($ millions, including the cost of power)	28.4	69.0	173.7	165.0

*Analyst's note: "average" values are near or above the 75th percentile for several data elements, indicating that there are a small number of organizations that are significantly larger than the rest of the population.

The majority of organizations noted that the fiscal year ends December 31st.

3. Salary Administration

Salary Range Adjustments – 2014 & 2015

The most common month for adjusting salary ranges is January (over 75% of reporting organizations).

Survey participants report adjusting their salary ranges in 2014 by an overall average of 2.6%.

Survey participants report planning to adjust salary ranges in 2015 by an overall average of 2.3%.

The salary range adjustments by employee level and overall are noted in the table below:

Year	CEO (n=25)	Executive (n=24)	Director (n=19)	Management (n=28)	Professional / Technical (n=25)	Admin. (n=25)	Overall (n=31)
2014	2.7	2.6	2.4	2.5	2.6	2.4	**2.6**
2015	2.3	2.3	2.3	2.3	2.2	2.3	**2.3**

Base Salary Increases – 2014 & 2015

The most common timing for adjusting salaries is January (over 75% of reporting organizations grant annual salary increases in that month).

Survey participants report adjusting actual salaries in 2014 by an overall average of 2.7%.

For 2015, survey participants reported projected average salary increases of 2.4%.

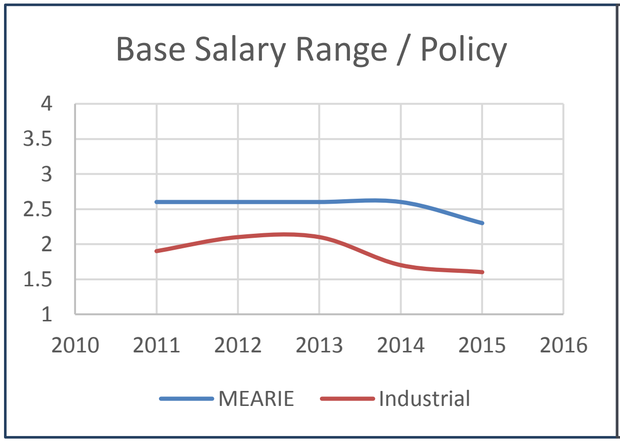
The base salary adjustments by employee level are noted in the table below.

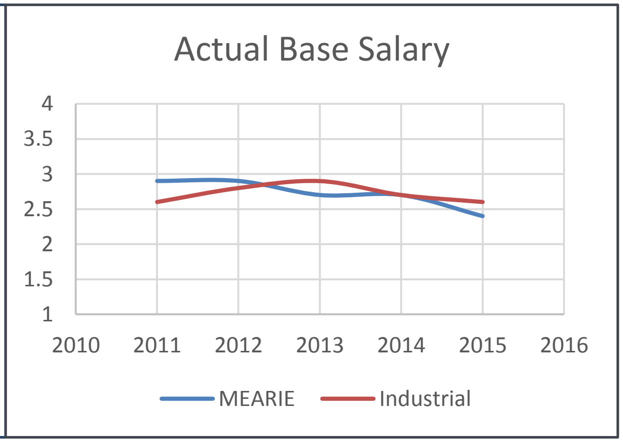
Year	CEO (n=32)	Executive (n=27)	Director (n=22)	Management (n=39)	Professional / Technical (n=29)	Admin. (n=30)	Overall (n=40)
2014	2.8	2.6	2.6	2.6	2.7	2.5	**2.7**
2015	2.7	2.3	2.4	2.3	2.2	2.2	**2.4**

Salary Trends

Hay Group compiles an annual compensation forecast survey across Canada, with over 400 participants annually.

The graph below depicts how the overall Canadian all industrial organization market has tracked from a range and actual salary perspective versus The MEARIE Group Management Salary Survey trend information over the past 5 years.





Generally, local distribution companies track very close to the all industrial market for actual salary adjustments; generally within 0.2%.

Surprisingly, local distribution companies track above that of the all industrial market for salary range adjustments. This indicates that the majority of salary budgets within the distribution companies may be allocated to range movements, as the differential between range and actual forecasts is typically 0.1%.

The differential in all industrial organizations is 0.7 %– 1.0% generally, which indicates that the all industrial organization may be allocating greater proportions of salary budgets to differentiation by merit, and enabling high performers to perhaps be paid above job rate and/or moving people through the range faster).

Incentive Programs

A majority of organizations (26 of 45 or 68%) indicated that they offer short term incentive pay opportunities to at least some portion of their employees.

Twenty-one (21) of the twenty-six (26) organizations who offer short term incentive pay provided information about their incentive plans.

a. Employee participation in short term incentive (STI) plans:
   - Eight (8) of the organizations indicated that all employee groups participated in STI.
   - The data indicates that five (5) organizations have STI plans for designated senior management and/or executives that do not extend to non-management staff.

b. Weighting of performance factors (corporate versus individual versus team/department performance) in the determination of individual bonus payments:
   - The average plan mix, by employee level, is provided in the table below. Totals may not equal 100% due to rounding.
   - Typical plan mix is a combination of corporate and individual metrics with a heavier weighting on corporate for senior management and/or executives and a heavier weighting on individual metrics for non-management staff.

Performance Factor	CEO	Executive	Director	Management	Professional / Technical	Admin.
Corporate	61.3 %	50.3 %	43.4 %	33.1 %	42.9 %	38.8 %
Team / Department	1.0%	5.3 %	4.4 %	9.8 %	0.0 %	0.0 %
Individual	37.7 %	44.3 %	52.2 %	58.8 %	57.1 %	61.2 %

Incentive Programs (continued)

Threshold Bonus Payouts

Formulaic or "target based" bonus programs typically do not pay out until a minimum level of performance (corporate, team and/or individual) has been achieved (i.e., if the threshold performance is not achieved, there is no pay out). Once this threshold performance has been achieved, incentive plans will pay out a minimum level of bonus; pay out levels typically then increase as performance / results increase, up to a "target" bonus rate when performance goals have been "met".

Twelve (12) of the 27 organizations with incentive plans reported that they define minimum levels of performance required before any bonuses are generated. The typical bonus rate at the threshold performance is set at 50% of "target" bonus.

Maximum Bonus

Bonus programs are often designed such that there is a maximum level of payout. For example: if a position has a 10% bonus and the maximum payout is 200%, or 2x, then the maximum amount the employee can achieve regardless of performance (i.e., how much targets are exceeded by), is 20% of their current base salary.

The average maximum bonus is provided by employee level in the table below, though the typical bonus pay maximum is 100% of target.

Maximum Bonus Payout %	CEO (n = 18)	Executive (n = 15)	Director (n = 12)	Management (n = 16)	Professional / Technical (n = 12)	Admin. (n = 12)
Average	123 %	129 %	127 %	123 %	134 %	138 %

In the broader market, it is more common to find higher maximum bonus levels (as a % of target) at higher levels of the organization, to reflect the greater influence on organizational performance that more senior roles are perceived to have.

Special (Project) Bonuses	Organizations were asked if they provide any project bonuses for participation in key / special projects, paid on successful achievement of specific milestones and/or on completion of the project, separate and distinct from annual incentive plans. Three (3) organizations reported providing such bonuses, but only one provided a value and as such there is insufficient data to provide the average value.

4. Benefit Policies

Car Benefit

The majority of organizations (33 of 45 or 73%) provide a car benefit to some level of employee.

The tables below summarize the value of car benefits, by position, where provided. An asterisk (*) indicates insufficient data to report:

		Company Owned Car (Value)	Monthly Lease Payment	Car Allowance
CEO	P75	*	*	925
	P50	42,500	*	750
	P25	*	*	586
	Average	41,375	*	793
	Number	4	2	24
Executive / VP	P75	*	*	675
	P50	*	*	505
	P25	*	*	338
	Average	39,983	*	546
	Number	3	2	12
Sr. Management / Director	P75	*	*	500
	P50	*	*	375
	P25	*	*	238
	Average	*	*	361
	Number	2	0	8

Four (4) organizations reported providing a car benefit to specified positions below Senior Management. Specifically, three (3) organizations provide use of a company-owned vehicle and one (1) provide an allowance where the incumbent is required to be available for off-hours call-in, such as operations supervisors, line superintendents, engineers and meter supervisors.

Mileage

The market statistics for mileage rates provided to employees as reimbursement for personal vehicle use are detailed in the table below.

N = 45	Mileage Reimbursement (¢ per km)
P75	54
P50	52
P25	48
Average	51

The most frequently reported mileage rate (12 organizations) is 54 cents per kilometer; the next most frequent reported rates are 55, 52, 51, 48, and 47 cents per kilometer (4 organizations each).

Perquisites

Club Memberships – Fitness

Twenty (20) organizations reported providing a subsidy for fitness club fees or provide a fitness facility on site. The typical policy is to provide a reimbursement of a fixed percentage (either 50 or 100%) up to a maximum amount per year. For eighteen (18) organizations, the same policy and maximum reimbursement applies regardless of job level; for one (1) organization, executives participate in a Discretionary Spending Plan that includes fitness, and so are not included in the reporting. One (1) organization provides access to an on-site fitness facility.

	Maximum Reimbursement per year
P75	$ 275
P50	$ 200
P25	$ 150
Average	$ 215

Club Memberships – Social

None of the organizations reported having a separate policy / program for reimbursement of social club fees.

Perquisites (cont'd)

Health Spending Account

Ten (10) organizations reported providing a Health Spending Account (i.e. discretionary spending within a defined range of services / benefits).

Of the ten organizations, one (1) provides this perquisite to senior officers only while nine (9) provide an HSA at all levels. Of those nine, six (6) provide the same funding for all jobs levels while three (3) differentiate by job level.

	CEO	Executive	Director	Management	Professional / Technical
P75	1,075	1,075	1000	750	750
P50	875	875	750	500	500
P25	438	413	350	300	300
Average	1,220	1,210	639	578	575
Number	10	10	9	9	9

2nd Opinion Medical Advice

Only three (3) organizations in the survey reported having a separate policy / program for this benefit.

Personal Financial / Legal Counseling

Three (3) organizations reported that financial and legal counseling is available via their Employee Assistance Program, which is provided to all employees.

Executive Medical Plan

Five (5) organizations reported providing enhanced medical coverage for executive levels only. Four (4) organizations reported a maximum dollar value, with an average maximum value of $1,134.

Perquisites (cont'd)

Personal Computer / Cell Phone / Internet

Thirteen (13) organizations provided information regarding policies and practices related to computers and internet.

The most common policies/practices are:

- Low / no interest rate loans to purchase computer equipment for personal / home office use
- Provision of laptops for particular levels of employee, in addition to office desktop, to allow for mobile work (note: may be a perquisite if personal use of computer is allowed, but not a perquisite if for business use only)
- Reimbursement for cell phone and/or home internet connection for selected employees (either full reimbursement or 50% reimbursement were both provided in the market place)
- Cash allowance intended to coverage cell phone and/or internet service

The value of these benefits varies dramatically by level within organizations and between organizations; the data does not lend itself to reporting of the value of typical practices. Excluding monthly cell phone allowances, allowances / loans are provided up to a maximum of $5,000 with an average value of $1,000 - $1,500.

Other Perquisites

Other programs / practices reported, by eight (8) organizations, include:

- Reimbursement of dues / fees for professional associations such as Engineers (P.Eng) and Accountants (CGA/CMA/CA)
- Provision of an Employee Assistance Program

Enhanced Life Insurance Coverage for Senior Officers

Organizations were asked if, for senior level jobs, there was additional, employer paid, life insurance coverage. For example, if the typical life insurance plan was 1.5x employee salary, was this enhanced to above 1.5x to some greater number such as 2x, or even 3x, for senior level jobs.

Eighteen (18) organizations provided information about their basic / standard life insurance coverage where the typical coverage is 2x annual salary (average coverage of 1.8x). Enhanced benefits are provided by seven (7) organizations, where senior roles receive coverage typically at 3x annual salary (average coverage of 2.4x).

Vacation Entitlement

Organizations provided the number of years of service required by various levels of employee in order to be entitled to a certain number of weeks vacation.

The following table below details the range, average and typical (i.e., most common) number of years of service required per weeks of entitlement.

Several organizations noted that for executive level jobs, vacations are typically negotiated versus following a schedule for entitlement.

	2 weeks	3 weeks	4 weeks	5 weeks	6 weeks +
CEO					
Range	N/A	Start – 6	Start – 11	Start – 18	Start – 27
Average	Start	2.3	6.1	12.7	20.5
Typical	Start	3	9	15	25
Executive / VP Level					
Range	N/A	Start – 6	Start – 11	3 – 18	15 – 27
Average	Start	2.4	5.7	14.1	22.6
Typical	Start	3	Start	16	25
Director Level					
Range	N/A	Start – 6	Start – 11	3 – 18	6 – 27
Average	Start	2.1	6.3	14.1	22.1
Typical	Start	Start	9	16	25
Manager Level					
Range	N/A	Start – 6	Start – 11	3 – 18	6 – 27
Average	Start	1.9	7.0	14.2	22.3
3Typical	Start	Start	9	15	25
Professional Level					
Range	N/A	Start – 6	Start – 11	5 – 18	15 – 28
Average	Start	2.3	7.4	14.6	23.1
Typical	Start	3	9	16	25

Unused Vacation

Organizations provided information about their policies and practices with regard to vacation time that was not fully utilized in the year in which it was earned.

Policy Regarding Carry Over	Number	%
Unused vacation entitlement at year end is paid out (vacation pay adjustment) – no carry over.	4	9%
Any/All unused vacation entitlement may be carried-over with no restrictions.	7	16%
Unused vacation entitlement may be carried over, subject to maximum total accumulated balance.	11	24%
A maximum amount of unused vacation may be carried over.	21	47%
No unused vacation may be carried over	2	4%
Total	45	100%

Maximum Number of Days to Carry Over (n=25)	Number of Days
Range	5 - 15
Average	8
Typical	5

Time Limit for Utilizing Carried-Over Vacation Time	Number
No limit	10
One Year	14
Six Months	13
Total	37

Note:

Some organizations reported variations to the above policies such as:

- Six (6) of the thirty-two (32) organizations who have a maximum amount of days that can be carried over specified it as either one year entitlement or a portion of the years entitlement. One (1) organization did provided the maximum amount of days that can be carried over.
- Differences by job level, such as more senior officers may carry over a greater number of days
- Differences by vacation eligibility, such as carrying over 10 days if eligible for up to 3 weeks' vacation but 20 days if eligible for 4 weeks' vacation
- Exception policies where workload or special projects caused the employee to be unable to fully utilize vacation time, or where carry forward beyond standard policy is regularly allowed but must be approved by senior management
- Cash out policies where some vacation time may be paid out instead of being carried over

Educational Assistance / Reimbursement

Twenty-five participating organizations (25) provided details with regards to education assistance / reimbursement policies ranging from eligibility criteria to pay back provisions. There are a wide variety of types of programs and reimbursement rates. Key highlights are provided below:

- Nineteen (19) organizations stated that there is a policy for education assistance / reimbursement; though typically there are limiters such as (1) education or training courses must be job related and (2) are subject to managerial approval
- Six (6) organizations stated that there is no formal policy, however, approval for educational assistance or reimbursement happens regularly and is on a case by case basis.
- Seven (7) organizations provided an annual reimbursement maximum, the average is $5,000 and the median is $2,000.
- Four (4) organizations provided a lifetime reimbursement maximum, the average is $21,400 and the median is $22,500.
- Payback provisions were provided by sixteen (16) organizations. The average time to not trigger any pay back provision is 2.4 years, the median is 2.0 years. The range of time is generally between 1 - 5 years and four (4) organizations noted they have some form of partial payment plan for leaving within a designated time period after completion of education. For example, if 4 years for no repayment, if the employee leaves in 2 years, they will be asked for 50% pay back.

5. Benchmark Position Survey Results

Survey Results

This section reports the information collected in aggregate values for each benchmark position. The values reported in this table reflect "All Ontario" data in that the data for all organizations matching to the position are included (regardless of size and geographic location).

Additional summaries, on a job by job basis, are provided in the accompanying "Addendum".

Detailed analysis, with expanded statistical data (i.e., including P25 and P75 data points) as well as analysis of survey results by geographic region, by customer base and by revenue, are reported in Excel files accompanying this report.

ALL ORGANIZATIONS

Code	Survey Job Title	JOB MATCHES: Sample Statistics Orgs	Incs	Hay Points P50	COMPENSATION DESIGN: Salary Range Minimum P50	Job Rate / Control Point / Policy P50	Salary Range Maximum P50	Target % (where eligible) P50	Total Cash Design P50	Total Cash Design AVG	ACTUAL COMPENSATION: Actual Base Salary P50	Actual Base Salary AVG	Actual Bonus % (where received) P50	Actual Total Cash P50	Actual Total Cash AVG
0000	President & CEO	39	39	1292	148,200	183,500	202,500	20%	194,100	226,000	183,600	187,000	22%	189,400	222,200
0001	Chief Operating Officer (COO)	11	11	994	126,000	162,500	162,500	10%	170,600	191,200	162,500	162,200	19%	170,600	197,800
0002	Head of Operations/Engineering	29	38	904	112,600	131,800	145,200	15%	135,000	148,900	133,700	135,800	14%	144,400	150,900
0003	CFO / Head of Finance	38	38	830	111,000	134,500	143,600	15%	140,600	159,000	138,200	143,600	14%	142,500	162,700
0004	Head of Customer Service	15	15	805	106,900	137,000	144,400	20%	144,200	151,300	141,300	137,100	19%	144,400	151,300
0005	Head of Regulatory Affairs	8	8	864	121,700	149,300	165,300	19%	174,700	170,000	151,400	153,000	17%	178,800	180,200
0006	Head of Human Resources	17	17	677	105,300	125,700	128,800	15%	142,100	147,200	124,500	131,100	14%	140,400	146,500
1000	Executive Assistant	30	48	245	57,400	68,700	76,900	5%	70,400	71,100	70,800	70,800	5%	71,800	72,900
1001	Administrative Assistant	15	30	198	50,400	59,700	64,300	5%	59,700	61,900	63,300	61,500	5%	63,800	62,900
2000	Director Engineering	14	15	744	103,400	126,200	127,100	13%	134,400	138,400	126,100	126,700	10%	131,000	138,000
2001	Engineering Manager	27	39	588	88,900	105,400	114,000	7%	107,900	111,500	105,900	105,700	5%	108,800	110,100
2002	Project Engineer	15	33	432	77,000	96,000	105,900	8%	99,000	96,100	93,600	92,500	8%	98,500	95,700
2003	Supervisor Engineering	19	30	432	82,600	94,400	103,300	5%	96,500	98,000	96,300	93,600	5%	100,700	97,100
2500	Director Operations	9	10	732	107,800	133,400	137,100	15%	146,900	142,200	128,000	132,800	15%	145,600	146,600
2501	Manager Operations	27	42	516	91,000	106,400	114,200	7%	109,200	112,300	104,400	105,500	7%	107,800	111,100
2502	Manager Control Centre	6	6	524	92,800	113,500	119,200	10%	123,100	123,200	116,400	116,000	10%	129,100	127,600
2503	Supervisor Control Centre	12	13	448	81,800	96,100	105,600	6%	98,400	101,300	97,900	100,400	7%	102,200	103,900
2504	Supervisor Protection and Control	5	5	466	92,100	95,700	107,900	*	100,400	108,700	98,800	103,800	*	98,800	110,600
2505	Supervisor Station Maintenance	9	13	466	80,500	97,300	108,700	8%	103,200	105,100	97,900	101,700	8%	100,000	106,700
2506	Line Supervisor	32	120	366	79,300	94,600	99,800	5%	96,900	96,500	96,800	96,400	5%	99,800	99,100
2507	Manager Meter Department	14	14	551	93,000	115,000	116,700	8%	121,900	117,600	107,200	106,800	7%	116,300	114,200
2508	Supervisor Meter Department	13	17	406	81,800	96,000	105,900	8%	99,800	98,700	97,100	97,200	5%	100,700	100,300

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

The MEARIE Group

2014 Management Salary Survey
Of Local Distribution Companies

ALL ORGANIZATIONS

		JOB MATCHES			COMPENSATION DESIGN						ACTUAL COMPENSATION				
Code	Survey Job Title	Sample Statistics		Hay Points	Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
		Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
3000	Director Supply Chain Management	3	3		*	*	*	*	*	144,800	*	136,800	*	*	158,700
3001	Manager Procurement/Inventory	17	19	451	82,200	94,700	106,900	8%	99,800	101,800	96,400	99,100	8%	102,200	104,600
3002	Supervisor Stores/Inventory	9	10	342	69,100	85,500	96,500	6%	85,500	89,100	85,900	86,400	6%	86,600	89,900
4000	Controller or Director Finance	17	27	588	92,200	108,200	113,600	10%	115,200	125,400	115,200	116,500	10%	121,000	125,500
4001	Manager Accounting	22	24	479	85,500	101,200	115,200	8%	107,800	109,500	92,600	98,600	6%	95,000	104,400
4002	Manager Risk Management	3	3		*	*	*	*	*	138,800	*	127,000	*	*	143,400
4003	Supervisor Accounting	10	16	363	71,500	88,600	94,800	5%	89,400	90,500	88,200	88,400	5%	91,500	91,300
4004	Financial or Business Analyst	14	25	342	71,400	85,100	90,700	5%	90,600	89,500	81,800	83,300	5%	84,700	86,700
4005	Accountant	11	20	332	63,900	77,800	86,400	4%	78,400	78,200	75,700	74,800	3%	75,800	76,000
5000	Director Customer Service	5	5	677	111,300	139,200	153,100	10%	160,000	145,300	140,100	135,000	14%	161,100	151,800
5001	Manager Customer Service	28	31	466	79,100	93,000	101,500	8%	93,000	94,900	93,400	91,800	6%	93,400	96,400
5002	Supervisor Customer Service	26	49	348	69,800	84,700	91,100	5%	87,300	86,200	81,400	82,300	4%	83,800	85,000
5500	Director Communications	8	8	677	102,200	131,500	153,400	15%	151,200	137,300	128,100	123,800	18%	150,400	141,700
5501	Manager Communications	11	11	393	73,800	87,000	98,300	8%	91,400	95,600	87,800	87,200	8%	94,700	92,600
6000	Director Regulatory Affairs	6	6	677	106,700	131,600	153,400	15%	151,300	152,100	140,900	140,700	16%	163,500	161,200
6001	Manager Regulatory Affairs	20	22	459	79,700	94,400	101,000	9%	96,800	97,900	94,700	94,800	6%	98,500	97,800
6002	Regulatory Accountant	15	18	342	65,400	81,200	96,500	7%	81,200	83,500	79,400	81,100	*	79,400	82,300
7000	Settlement or Rate Analyst	10	14	363	67,700	81,000	90,600	5%	85,600	88,600	85,500	82,900	7%	88,700	86,100
7001	Director or Officer, Conservation	7	7	805	106,100	131,600	149,000	18%	157,200	159,600	131,400	134,000	19%	141,100	150,000
7002	Manager Conservation & Demand	22	26	393	76,800	90,000	99,600	10%	91,100	94,500	89,200	90,100	8%	92,800	94,600
8000	Director Information Systems	15	15	830	106,800	129,300	139,700	15%	148,700	145,100	125,700	130,800	13%	138,300	146,600
8001	Manager Information Systems	16	27	488	84,300	97,100	104,200	8%	102,800	104,000	99,400	99,200	8%	100,300	106,600
8002	Systems/Program Administrator	21	34	332	67,100	80,600	87,700	5%	83,800	82,700	86,400	83,300	4%	90,400	85,800
9000	Human Resources Manager	8	10	479	88,400	104,700	104,700	8%	109,900	105,200	95,500	95,200	6%	106,500	101,200
9001	Human Resources Generalist	14	27	328	66,100	79,200	85,000	5%	80,000	84,100	77,600	77,800	6%	79,000	81,500
9002	Human Resources Coordinator	7	7	233	57,700	72,100	72,100	7%	75,700	73,900	66,600	68,100	8%	66,600	71,000
9003	Payroll	18	20	245	59,000	70,800	78,000	5%	72,500	74,400	71,600	72,600	4%	72,800	75,000
9004	Manager, Health & Safety	20	23	479	83,400	99,800	107,800	7%	101,000	105,400	103,400	100,500	6%	105,700	105,800

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

APPENDICES

A. Survey Methodology

A brief profile was developed for each benchmark position. These profiles were incorporated into a survey package and distributed to each participant along with a data submission spreadsheet requesting data on survey benchmark positions, as well as the organization's profile and selected salary administration & benefits policies.

Participants matched their jobs to the profiles and provided data for each position, where applicable. For each position where an organization submitted more than one match, the data were aggregated and an average figure was used for that organization. By using this methodology, all organizations carry equal weighting, and no one single organization excessively influences the market statistics by virtue of the size of its employee population.

Once the completed surveys were returned to Hay Group, participants were contacted for data verification as necessary. Hay Group also initiated a number of follow-up actions to clarify information provided by the participants. All of the matches submitted by the participants were reviewed by Hay Group to determine their appropriateness versus the job profiles and the market. If deemed inappropriate, the matches, or outlier data, were removed from the survey results.

Where possible, organization charts or details regarding reporting relationships were provided to Hay Group to enable understanding of the roles. From the job match information, plus a review of organization charts and other contextual information provided, Hay Group has estimated at which Hay Reference Level each organizations' roles fall to facilitate point-based comparisons.

B. Definitions – Compensation Elements

Salary Range

Minimum	The lowest salary/rate that the organization is prepared to pay for an incumbent in the position. May be the starting salary for inexperienced/non-qualified hire.
Job Rate / Control Point	Typically the midpoint of the salary range, intended to reflect the salary the organization is prepared to pay for sustained competent performance by a fully trained / qualified incumbent.
Maximum	The highest point in the salary range (or step progression). Note: might be the same as "job rate".

Short Term Incentive — *Short Term Incentive (STI) refers to any incentive arrangement designed to reward an individual for performance/results achieved over a performance cycle/period of up to one year.*

Target	Target bonus is the level of award (either a % of salary or a fixed dollar amount) that an employee in this position would expect to receive if all corporate, team and individual performance goals are "met" (as planned). This rate/amount is often communicated to employees as part of the incentive/bonus plan design, e.g. "the target bonus for jobs in grade/band 6 is 8% of salary".
Discretionary	Discretionary plans have no target bonus rate and pay out at the end of the year at the discretion of executive/board.

Current Salary — The amount paid for work performed on a regular, ongoing basis. Does not include variable bonus or incentive payments, sales commissions, shift premiums, or overtime payments.

Actual STI (Paid) — *Total of all STI awards paid to the incumbent(s) for performance/results over the latest completed fiscal year.* May be paid during the year or after year end. (Note: recorded and reported on an annual basis)

C. Definitions – Statistical Elements

Market data are reported using the following statistics:

	Definition	Reporting Requirement (# of Observations Necessary to Report)
P90	90th percentile If all observations were sorted and listed from highest/largest to lowest/smallest, 10% of the observations would fall above the 90th percentile and 90% would fall below	**11**
P75	75th percentile If all observations were sorted and listed from highest/largest to lowest/smallest, 25% of the observations would fall above this value and 75% would fall below	**7**
P50	50th percentile, also referred to as "median" If all observations were sorted and listed from highest/largest to lowest/smallest, 50% of the observations would fall above this value and 50% would fall below	**4**
P25	25th percentile If all observations were sorted and listed from highest/largest to lowest/smallest, 75% of the observations would fall above this value and 25% would fall below	**7**
P10	10th percentile If all observations were sorted and listed from highest/largest to lowest/smallest, 90% of the observations would fall above this value and 10% would fall below	**11**
Average	The arithmetic mean of all values, calculated by adding up all of the values and dividing by the number of observations	**3**

D. Benchmark Position Profiles

Job Title	Description
President & CEO	Directs the development of short and long term strategic plans, operational objectives, policies, budgets and operating plans for the organization, as approved by the Board of Directors. Establishes an organization hierarchy and delegates limits of authority to subordinate executives regarding policies, contractual commitments, expenditures and human resource matters. Represents the organization to the financial community, industry groups, government and regulatory agencies and the general public.
Chief Operating Officer (COO)	Highest ranking operations position. Reporting to the President/CEO, directs the operational elements of the organization, could include operations & engineering, customer services, metering and information technology. Develops the short and long term strategic plans, directs the development of operational objectives, policies, budgets for his/her areas of accountability. The position reports directly to the President/CEO.
Head of Operations and/or Engineering	Highest ranking operations/engineering position. Reporting to COO or President. Directs both the operations and engineering functions. Develops the short and long term strategic plans, formulates and implements plans, budgets, policies and procedures to facilitate and improve processes. Establishes clear controls, objectives and measures to ensure safe and appropriate delivery of power and power related services. Evaluates the feasibility of new or revised systems or procedures and oversees operations and engineering to ensure compliance with established standards.
CFO / Head of Finance	Highest ranking financially-oriented position within the company. Reporting to the President &CEO, this strategic role plans directs and controls the organization's overall financial plans, policies and accounting practices and relationships with lending institutions, shareholders and the financial community in mid to large organizations. Provides advice and guidance for the Board of Directors on financial matters. May direct such functions as finance, general accounting, tax, payroll, customer billing, regulatory affairs, and information systems and may be responsible for Administration functions. Normally possesses a CA, CMA or CGA designation.
Head of Customer Service	The highest-ranking customer service position in the utility. Provides direction for all departmental activities, services and practices, including customer care/call centre, billing, credit and collections. Accountable for the development, implementation and integration of all customer service related activities to achieve a competitive advantage through customer driven initiatives and strategies. Directs and oversees the implementation of customer service standards, policies and procedures; manages and coordinates budgets.
Head of Regulatory Affairs	Represents the organization on quality and regulatory matters before government agencies and conformity assessment bodies including providing of evidence, regulatory filings, supporting analyses, position papers, interrogatory responses, etc. Keeps abreast of on-going developments in regulatory practices affecting electrical distribution utilities. Ensures that regulatory information is disseminated throughout the organization in a timely and effective manner. Is responsible for the filing of written communications and regulatory submissions to government agencies (OEB) and conformity assessment bodies (IMO). Generally reports to President & CEO or a senior executive.
Head of Human Resources	The highest-ranking human resources position in the organization. Provides direction, support and alignment of organization-wide Human Resources practices and systems with the business in terms of mission, vision and the strategic imperatives. Ensures that existing needs and future demands of internal customers are met through a cost effective and efficient HR services. Directs HR management and staff in the development and implementation of Human Resources strategy, policies and programs covering employment, negotiations & labour relations, training, compensation, organization development, performance management, benefits and may include health & safety. Provides coaching and counsel to the executive and Board of Directors.

Administration

Executive Assistant	Performs advanced, diversified and confidential administrative duties requiring broad knowledge of organizational policies and practices. Initiates and prepares correspondence, reports, either routine or non-routine. Screens telephone calls and visitors and resolves routine and complex inquiries. Schedules appointments, meetings and travel itineraries. In some cases, may have responsibility for routine HR and administrative services. Records, prepares and distributes minutes of meetings, including Board of Director minutes. Reports to the President & CEO and may provide support to other executives.
Administrative Assistant	Performs advanced, diversified and confidential administrative duties for executives and/or senior management, requiring broad and comprehensive experience and knowledge of organizational policies and practices. Prepares correspondence, reports, either routine or non-routine. Screens telephone calls and visitors and resolves routine and complex inquiries. Schedules appointments, meetings and travel itineraries. Reports to a senior executive or executive team.

Engineering

Director Engineering	Plans and directs the overall engineering activities and engineering staff of the organization. Formulates and implements plans, budgets, policies and procedures to facilitate and improve processes. Coordinates the creation, development, design and improvement of the organization's projects and products in conformance with established programs and objectives. Oversees plans, resources and budgets of the department aligned with business strategy.
Engineering Manager and/or Distribution Engineer	Supervises and directs the work of an engineering division such as distribution, line design, transmission planning, distribution planning and/or civil engineering. Responsible for engineering work involving a wide scope of assignments. Handles personnel coordination and issues of the division, prepares estimates, specifications and designs, including the supervision, planning and scheduling of work within the division – Requires a P. Eng. OR Supervises engineering technicians or service technicians. Directs and coordinates the activities, schedules and projects of the construction and maintenance group of those involved with the distribution of electrical power from transformer substations, construction and maintenance of distribution systems. Consults with other department management on plant design, construction and maintenance. Prepares monthly operating reports, budget estimates, and work and materials specifications. Reviews and approves material requisitions, work authorizations and drawings for facilities. Requires a P. Eng.
Project Engineer	Non-supervisory position. Directs and coordinates activities related to utility engineering project work, such as smart grid systems, renewables, large utility projects, asset renewal, etc. Requires a P. Eng.
Supervisor Engineering	Supervises a small technical work group which may include CAD operators and/or engineering technicians. Coordinates the development and maintenance of engineering and construction standards and systems (GIS, AM/FM, CAD). Organizes, stores and maintains the integrity of hard copy file records, digital formats and mapping standards. Normally requires a C.E.T. or A.Sc. T. Typically reports to an engineering manager.

Operations

Director Operations	NOT the head of function. Plans and directs all operations functions (no engineering responsibility), of the utility. Formulates and implements plans, budgets, policies and procedures to facilitate and improve processes and establishes clear controls, objectives and measures to ensure safe and appropriate delivery of services and clarity of roles and responsibilities. Evaluates the feasibility of new or revised systems or procedures and oversees operations to ensure compliance with established standards.
Manager Operations	NOT the head of function. Supervises, co-ordinates, directs, schedules and controls the construction, maintenance and personnel of the division, including budgets, transportation, equipment and material requirements and fleet management. Division responsibilities include construction, maintenance and repair of all overhead transmission, overhead and underground distribution and may include coordination of tree trimming for geographical area assigned to the division. In smaller utilities, a professional engineer may fill this role.
Manager Control Centre	Supervises, co-ordinates, directs, schedules and controls the control centre and technical staff. Provides leadership in the planning and coordination of the control centre relative to safety, reliability and control of the distribution system. Is responsible for budgets, and the direct operations of the control centre approving system outages, switching and maintenance requirements to maintain and improve system reliability.
Supervisor Control Centre	Directs and supervises control centre technical staff. Provides planning and coordination of control centre scheduling and maintenance required for the safe, reliable operation and control of the distribution system, including the authorization of the operation of system devices, equipment and control access to electrical plant and substations. Approves and coordinates system outages and switching as required for maintenance and system reliability. Oversees power interruptions and emergencies with dispatch staff to affect corrective measures for isolation, emergency repairs and restoration purposes. Monitors feeder load profiles.
Supervisor Protection and Control	Responsible for the management of all Protection & Controls activities related to the installation, maintenance and commissioning of: Protective Relaying Schemes and Station Automation Systems; SCADA System, Visual Display System and Remote Terminal Units; Operations Ethernet and system-wide Area Communications Networks; Distribution Automation Systems, Sectionalizing Devices and Remote Supervisory Controlled Devices. Prepares and administers reports, budgets, Policies and Procedures, record keeping systems.
Supervisor Station Maintenance	Responsible for the planning, coordinating both maintenance and installation of substations, as well as ensuring reliability of the underground plant, through testing and troubleshooting. Supervises, coordinates and schedules the activities of Station Maintenance Electricians and Protection and Control Technicians, Reviews work assignments, daily logs, reports and orders. Co-ordinate crews and plan jobs, assigns work per shift, long-term work and shift coverage to ensure the smooth flow of routine work and that all shifts are covered.
Line Supervisor	Coordinates and directs the lead journey person and/or crews in the construction and maintenance of distribution lines and equipment (overhead and/or underground). Works with lead journey person to develop plans and schedules required in directing and assigning a crew or crews of skilled trade staff in performing construction, maintenance and operation of the distribution system lines in a safe and efficient manner. Supervises and coordinates subcontractors engaged in planning and executing work procedures, interpreting specifications and managing construction.
Manager Meter Department	Supervises the overall operations of the Meter department, prepares budgets, directs the purchase and maintenance of equipment and technology related to the department. Provides direction on the supervision of meter staff, the assignment of work and productivity of staff. Supervises the work related to interactions with electronic meter programming and interaction with/or the operation of the MV90 or similar data collection systems.

Supervisor Meter Department	Responsible for overall operation of the Meter department, including operations, budgeting and supervision of meter technicians or other operations staff. Assigns, monitors and inspects the daily work and productivity of the staff in metering operations to ensure timely delivery of services, maintenance of equipment and identification of issues. Develops work plans for the department that include supervising meter re-verification, new meter installs, record maintenance and monitoring of meter maintenance, damage, reporting and theft issues. Ensures compliance with technical standards for equipment. Responsible for electronic meter programming and interaction with/operation of an MV90 or similar data collection system.

Supply Chain / Procurement

Director Supply Chain Management	Responsible for the overall operation of the Procurement, Inventory, Fleet and/or Facilities programs and initiatives in the organization. Formulates and implements plans, budgets, policies and procedures to facilitate and improve processes and establishes clear controls, objectives and measures to ensure safe and appropriate delivery of services and clarity of roles and responsibilities. Oversees the establishment of user service level agreements, and provides contract management expertise and acts as a resource for contract negotiation, review and approval. Directs the effective capital acquisition and maintenance of the corporate fleet and/or directs the effective maintenance and capital investment of the organizations facilities and assets.
Manager Procurement and/or Inventory and/or Facilities and/or Fleet	Responsible for all purchasing and/or inventory and/or facilities and/or fleet for all areas of the utility. Negotiates vendor agreements and manages the tender process. May also be responsible for stores and inventory control in the warehouse. Is responsible for budgets, policies and procedures and directs the work of the purchasing or buyers and/or stores and/or facilities and/or fleet personnel. Works with the organization in setting partnership relationships to understand and meet the needs of the organization, its operations and risk associated with the effective and efficient operations of the company.
Supervisor Stores/Inventory/ Warehouse	Supervises inventory control, records and stores operation. Orders material to maintain on-hand quantities with procurements approval. Responsible for testing safety equipment, i.e., hoses, blankets, gloves, etc., small tool and equipment repair and reconditioning. Assists procurement department in the sale of obsolete equipment and material.

Accounting / Finance

Controller or Director Finance	NOT the head of function. Responsible for all financial reporting, accounting and record keeping functions. Directs the establishment and maintenance of the organization's accounting and finance principles, practices and procedures for the maintenance of its fiscal records and the preparation of its financial reports. Directs general and property accounting, cost accounting and budgetary control. Appraises operating results in terms of costs, budgets, operating policies, trends and increased profit opportunities. Reports to a CFO/VP Finance.
Manager Accounting	Manages the general accounting functions and the preparation of reports and statistics reflecting earnings, profits, cash balances and other financial results. Formulates and administers approved accounting practices throughout the organization to ensure that financial and operating reports accurately reflect the condition of the business and provide reliable information. Reports to Controller/Director Finance or CFO/VP Finance.
Manager Risk Management	Responsible for risk management activities including cash flow management, credit facilities management, insurance and support for credit and collection policies throughout the corporation. May be responsible for ensuring that cash liquidity risk is managed in an appropriate fashion such that bank account balances are sufficient to meet operational, capital expenditures and debt servicing requirements while minimizing short-term borrowings or surplus investing. Provides leadership in the developing new and refining existing risk management policies to respond to changes in risk tolerances and business conditions and as financial risks are better understood in accordance with industry best practices. Reports to Head of Finance or COO or CEO.

Supervisor Accounting	Coordinates activities of the payable/receivable clerks. Supervises accounts payable and receivable transactions, entries and trial balances; responsible for the accuracy of all journal entries and reconciliation of invoices; updates credit department on account status.
Financial or Business Analyst	Conducts analysis of information for budgeting, investment and financial forecasts; applies principles of accounting to analyze past and present financial operations; estimates future revenues and expenditures; prepares budgets; develops and maintains budgeting systems; processes and prepares business transactions and reports, reconciles ledgers and sub-ledgers, cash flow projections, entry of source documents. Holds a financial designation, either CA, CMA or CGA.
Accountant	Supports the organization decisions through financial information and relevant analysis. Ensures the integrity between the CS work order systems and general ledger system is maintained. Initiate corrective measures when discrepancies occur between the systems. Collects and combines information for the decision making process by management, including financial statements and special projects as assigned (e.g. preparation of rate submission supplemental information).

Customer Service

Director Customer Service	NOT the head of function. Provides direction for all departmental activities, services and practices, including customer care/call centre, billing, credit and collections. Accountable for the implementation and integration of all customer service related activities. Oversees the implementation of customer service standards, policies and procedures; manages budgets; manages activities of CS managers and/or supervisory staff.
Manager Customer Service and/or Billing	NOT the head of function. Manages a team of customer service and/or billing representatives in providing information, receiving and responding to customer inquiries, complaints or requests. Develops and maintains customer information systems, processes and procedures including billing, credit, deposits and collections. Liaises with representatives of other organizations and customer groups to share information and resolve administrative, organizational and technical problems. Responds to elevated customer complaints. This function may also be responsible for coordinating meter installation/maintenance, residential electric service connections, and service calls.
Supervisor Customer Service and/or Billing and/or Collections	Supervises customer service representatives (billing clerks and/or collections clerks) and coordinates customer service programs within the framework of established customer service policies. Schedules and organizes staff to accommodate anticipated workflow from bill inquiries, delinquent accounts, re-connections and disconnections, customer deposits, etc. Recommends corrective steps to address customer issues and refers unique issues to manager for response.

Regulatory Affairs

Director Regulatory Affairs	NOT the head of function. Supports the VP or may represent the organization on regulatory matters before government agencies and conformity assessment bodies including providing of evidence, regulatory filings, supporting analyses, position papers, interrogatory responses, etc. Ensures that regulatory information is disseminated throughout the organization in a timely and effective manner. Is responsible for or supports the filing of written communications and regulatory submissions to government agencies (OEB) and conformity assessment bodies (IMO).
Manager Regulatory Affairs	NOT the head of function. Manages the organization's regulatory staff, programs and activities to ensure compliance. Assists the organization on quality and regulatory matters before government agencies, providing research and analyses. Ensures that regulatory information is disseminated throughout the organization in a timely and effective manner. Coordinates the filing of written communications and regulatory submissions to government agencies (OEB) and conformity assessment bodies (IMO).

Regulatory Accountant	Ensures that the accounting activities for regulatory financial reporting are in compliance with all Ontario Energy Board (OEB) policies and guidelines. Act as a key resource to provide expert advice and recommendations in the implantation of all OEB, OPA and IESO codes and regulations in order to ensure corporate compliance. Track and reconcile all OEB accounts, including business rationale for changes in balances, cost side of accounts subject to prudency review (i.e. conservation, smart meters) and the cost side of Ontario Power Authority (OPA) programs.

Conservation / Demand

Settlement or Rate Analyst	Responsible for recording, creating, analyzing, processing and reconciling metering data. Operates and administers an MV-90 or similar data collection system, downloading, validating, editing, estimating and processing interval meter-related information. Has in-depth understanding of commercial billing practices, the IMO and the OEB's Retail Settlement Code. Analyses rates using rate sensitivity models and develops appropriate rate structures, using the specific models.
Director or Officer, Conservation and Demand Management	This position is responsible for planning, coordinating, evaluating and delivering energy and water conservation and demand management programs. Develops plans for programs in accordance with the OEB's conservation and demand management code to ensure achievement of OEB mandated energy consumption and demand conservation targets.
Manager Conservation & Demand/Marketing	Responsible for managing the development and implementation of CDM initiatives as well as the marketing communications expertise and support required for the successful delivery of the company's Conservation and Demand Management (CDM) programs. Marketing communication plans may include, but are not limited to advertising, media conferences, program launch events, workshops, event displays. Liaising with, as needed, senior marketing and/or communications personnel representing organizations and groups involved in conservation and sustainability including, but not limited to, the Ontario Power Authority (OPA), the Ontario Energy Board (OEB), Ministry of Energy, municipal and regional governments, etc.

Information Systems / Technology

Director Information Systems	Accountable for operations and alignment of the Information and Telecommunication Systems with the business in terms of organization objectives and imperatives. Ensures that existing needs and future demands of internal and external customers are met through a cost effective and efficient information and telecommunication infrastructure. Oversees IS management in areas of computer operations, systems planning, design, security, programming and telecommunications. Reviews and evaluates project feasibility and needs based upon management's and business requirements and priorities. Develops departmental plans, strategy, budgets and resource requirements. Typically reports to President & CEO, or CFO.
Manager Information Systems and/or Security	Manages and directs staff in areas of computer operations, systems planning, design, security, programming and telecommunications. Develops and maintains systems standards and procedures and assigns work to department staff. Reviews and evaluates project feasibility and needs based upon management's and business requirements and priorities. Develops departmental plans, project plans, budgets and resource requirements.
Systems/Program Administrator or Applications/Systems Support Professional	Responsible for maintenance of software systems including system analysis, programming and design, updates and changes. Makes a preliminary study of new applications and recommendations to implement them, including hardware and software. Troubleshoots and corrects problems in existing programs, other than normal problems, usually caused by changes of software or hardware.

Human Resources

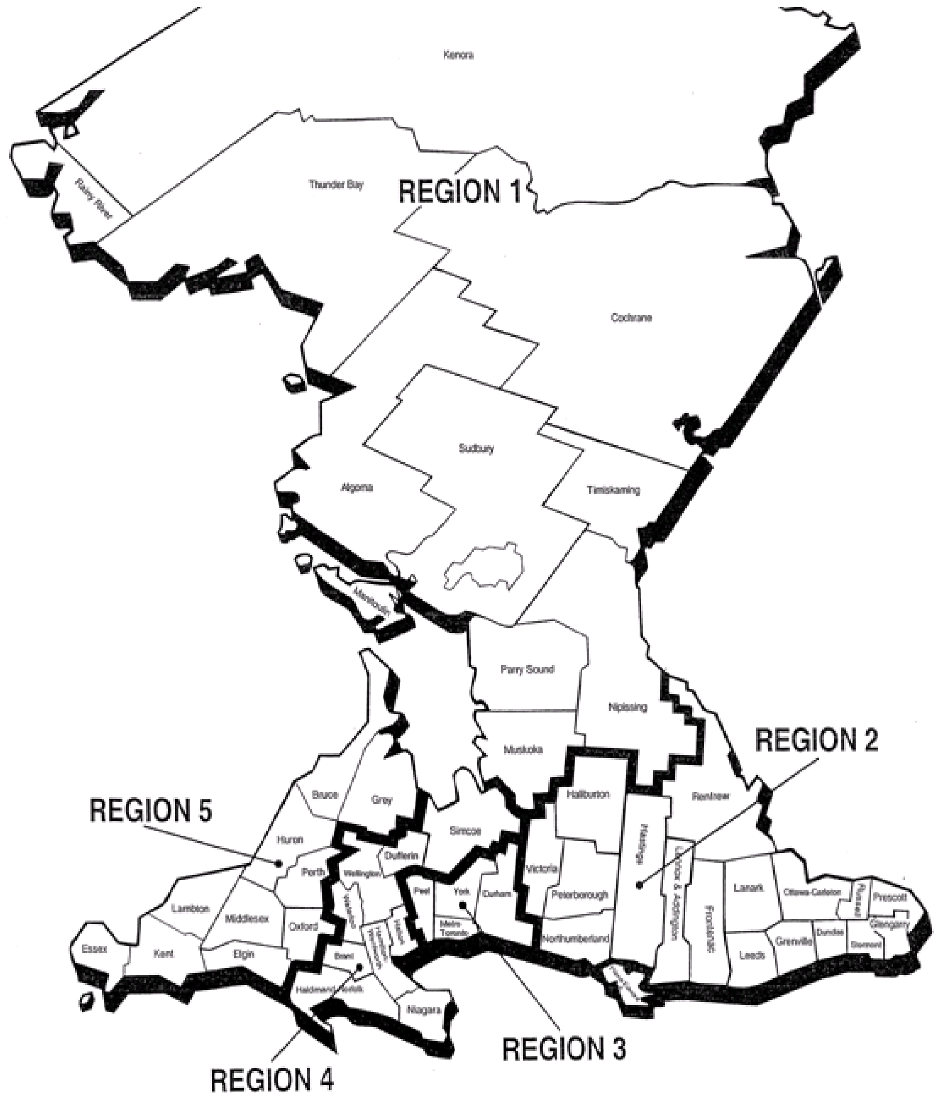
Human Resources Manager	NOT the head of function. Develops and implements human resources programs, including compensation, benefits, recruitment, performance management, labour relations/negotiations, training and development, assists in policy development, HR planning, record keeping or payroll etc. May supervise a team of HR professionals or support staff. Reports to a senior HR professional (Director or VP or equivalent).
Human Resources Generalist	Assists in the development and implementation of human resources policies and programs by providing support and guidance to managers and employees in the areas of compensation, labour relations, employee relations, performance management, benefits, recruitment, training and HRIS systems. Acts as a business partner to the organization in the areas of human capital. May assist in the preparation of negotiations.
Human Resources Coordinator	Administrative support to one or more functional areas of HR and/or Safety. Processes, coordinates and enters into a HRIS or other system, a variety of documents including employment applications, benefits, compensation and payroll changes and confidential employee information. Responds to routine employment questions and distributes and maintains manuals and employee program communications.
Payroll	Performs the payroll coordination and administration. Maintains the organizations internal or external payroll system. Prepares monthly requisitions for WSIB, Employee Health Tax, Receiver General, OMERS Pension and Union Dues. Administers employee pension program and provides pension calculation estimates as requested. Reconciles monthly payroll for year-end finance procedures. Prepares annual T4's and T4A's and OMERS Pension and responds to inquiries from employees and pensioners regarding the pension plan.
Manager, Health & Safety	Accountable for the development and implementation of occupational health, safety and environmental programs, including training, maintenance of safe working conditions, investigation and reporting of workplace accidents. Also identifies areas of potential risk and makes recommendations to reduce or eliminate potential accident or health hazards in compliance with government regulations.

Communications

Director Communications	Directs the development, management and execution of internal and external corporate communications strategies for the company, and marketing and public relations initiatives. Acts as the Chief Spokesperson for the organization. Leads the management and development of the corporate brand and identity. Oversees the development, production and distribution of corporate publications including, but not limited to, the annual report, customer newsletters, information brochures, bill inserts, CDM/Green marketing materials, employee newsletters and media releases. Directs the development and management of the company's external (corporate internet site) and internal (corporate intranet site) web presence and strategy. Oversees the management and execution of internal and external corporate events as well as community-relations activities such as sponsorship and donation programs.
Manager Communications	Responsible for managing the development and implementation of all customer communications initiatives as well as the marketing communications expertise and support required for the successful delivery of the company's CDM and customer communications materials/systems. Communication materials may include, but are not limited to, customer newsletters, information brochures, bill form design, employee intranet, LCD information monitors, and website communications. Working in conjunction with Regulatory Affairs, develop materials or other communication methods to communicate regulatory changes/issues that may directly impact the customer. Manages event planning for internal and external company events.

E. Regions

The map below identifies the 5 regions that will be used for reporting on a geographic basis.



Attachment 1-SEC-4-B: 2016 MEARIE Survey

The MEARIE Group

2016 Management Salary Survey
Of Local Distribution Companies

SURVEY REPORT

August 2016

SURVEY ADMINISTRATOR: Korn Ferry Hay Group

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Section

Appendices

1. Introduction

The MEARIE Group is pleased to present this report of the 2016 Management Salary Survey of Local Distribution Companies (LDCs).

In today's competitive talent market, LDCs are challenged with establishing and maintaining competitive, yet affordable, compensation programs and policies. The MEARIE Group established the Management Salary Survey of Ontario's Local Distribution Companies to assist LDCs in understanding the competitive landscape and to support your efforts to develop pay practices that attract, motivate and retain high quality, high performing employees.

The survey was updated in 2012 through the combined efforts of The MEARIE Group's *HR Information Solutions* team, outside consultants and representatives of our members, all working together to ensure that the Survey continues to meet the evolving needs of member LDCs.

The Survey was further enhanced from 2013 to 2014 through our partnership with Korn Ferry Hay Group ("Hay Group"), a globally renowned compensation consulting firm. Hay Group drew upon their expertise and experience in developing and managing salary surveys across all sectors of the economy and in numerous countries around the world.

There are no substantial changes to the survey in 2015 or 2016.

The 2016 survey includes:

- Geographic, Number of Employees, Number of Customer and Revenue size reporting.
- Fifty (50) benchmark descriptions, supported by the Hay Group job evaluation methodology for improved reporting and greater ability to identify the impact of organization size and structure.
- Continued reporting of "total cash compensation" to provide greater depth of information regarding market pay practices.
- An overview of local distribution company market trends and compensation projections for 2017 budget planning.
- MS Excel survey reporting including versions of position salary tables by All Organizations, Geography, Revenue and Customers to support those organizations that wish to conduct further analysis of the results and to assist in transferring survey results into internal reporting.

The survey includes two presentation documents and Excel data tables in formats as follows:

- PDF Documents:
    - Survey Report Executive Summary containing a complete analysis and a data summary of all the positions.
    - Survey Report addendum which includes a complete analysis of each position, presented on one page.
- Excel Documents which are provided for easy data export and printable to one legal sized page, showing LDC Survey data by:
    - All Organizations
    - Region
    - Customer Base
    - Revenue
    - Number of Employees

We would like to thank you for your participation. As a result of the strong response, we are able to provide you with an informative and detailed survey that will help you in the support of your organization's compensation programs.

CONFIDENTIALITY POLICY

The MEARIE Group recognizes the importance of maintaining the security of your information and has developed the following policy that applies to all participants (and their delegates) in the Management Salary Survey (a "Survey"), as well as Hay Group (survey administrators) and The MEARIE Group.

An individual LDC will provide its authorization for the sharing of information identified as being information of that LDC by completing the Survey Data Submission for a Survey. This will result in the LDC's data being identified by name in the listing of participants. This enables participants to be aware of the names of the other participants in the Survey to determine the relevance of Survey data cuts (e.g. by geography or size).

All of the information obtained through a Survey will be treated with the utmost confidentiality. Data will be reported on an aggregate basis only, and in such a way as to ensure that individual participant data cannot be identified/attributed. Standards for minimum number of data will be strictly enforced to ensure confidentiality. Neither Hay Group nor MEARIE Group will release or disclose to any other person whatsoever any information pertaining to any individual LDC participant.

Survey results will be reported only to those LDCs who participate in the Survey and provide comprehensive data. Comprehensive participation means that each LDC is expected to match as many of the Survey benchmark positions as they are able, and provide data for all incumbents of matched positions. **All participants must consider this information as strictly confidential.**

The results of a Survey will not be disclosed/sold to or shared with organizations that have not participated in that Survey, whether by The MEARIE Group or Hay Group or Survey participants. **Participants may not share the Survey reports/results with non-participant LDCs or any entity under any circumstances.**

The data collected for a Survey may also be included in the Hay Group's Canadian compensation database. Information in the Hay Group database is maintained with the highest standards of confidentiality; analysis and reporting of data is on an aggregate basis only, and in such a way as to ensure that individual participant data cannot be identified or attributed. As of January 2016, there are over 540 employers represented in the Hay Group database. Should you have any questions or for further information, please contact Deirdre Chong Smith, Consultant at Korn Ferry Hay Group at 416-815-6344 or deirdre.chong@kornferry.com.

The obligations of confidentiality set out in this policy are subject to the requirements of applicable law. However, LDCs may not disclose the existence or results of a Survey to any regulatory body (or other person) unless compelled by law to do so, and if an LDC is compelled by law to make such a disclosure, it will give The MEARIE Group as much notice in advance as possible of the disclosure and the reasons the disclosure is legally required. In such circumstances, the LDC will take such steps as The MEARIE Group reasonably requests, or will co-operate with respect to any steps The MEARIE Group reasonably wishes to take, to contest or limit the scope of the disclosure.

The MEARIE Group will not be liable for breaches by participating LDCs or Hay Group of this Confidentiality Policy.

2. Survey Overview

Survey Benchmark Positions

The survey covers 50 benchmark positions representing a cross-section of the functions within member organizations. The benchmark positions were reviewed in 2012 by a working group of LDC sector Human Resources professionals. Job profiles for each benchmark job were developed and reviewed by the consultants and the HR group.

Senior Management	0000	President & CEO
	0001	Chief Operating Officer (COO)
	0002	Head of Operations and/or Engineering
	0003	CFO / Head of Finance
	0004	Head of Customer Service
	0005	Head of Regulatory Affairs
	0006	Head of Human Resources
Administration	1000	Executive Assistant
	1001	Administrative Assistant
Engineering	2000	Director Engineering
	2001	Engineering Manager and/or Distribution Engineer
	2002	Project Engineer
	2003	Supervisor Engineering
Operations	2500	Director Operations
	2501	Manager Operations
	2502	Manager Control Centre
	2503	Supervisor Control Centre
	2504	Supervisor Protection and Control
	2505	Supervisor Station Maintenance
	2506	Line Supervisor
	2507	Manager Meter Department
	2508	Supervisor Meter Department

Supply Chain / Procurement	3000	Director Supply Chain Management
	3001	Manager Procurement and/or Inventory and/or Facilities and/or Fleet
	3002	Supervisor Stores / Inventory / Warehouse
Accounting / Finance	4000	Controller or Director Finance
	4001	Manager Accounting
	4002	Manager Risk Management
	4003	Supervisor Accounting
	4004	Financial or Business Analyst
	4005	Accountant
Customer Service	5000	Director Customer Service
	5001	Manager Customer Service and/or Billing
	5002	Supervisor Customer Service and/or Billing and/or Collections
Communications	5500	Director Communications
	5501	Manager Communications
Regulatory Affairs	6000	Director Regulatory Affairs
	6001	Manager Regulatory Affairs
	6002	Regulatory Accountant
Conservation / Demand	7000	Settlement or Rate Analyst
	7001	Director or Officer, Conservation and Demand Management
	7002	Manager Conservation & Demand / Marketing
Information Systems	8000	Director Information Systems
	8001	Manager Information Systems and/or Security
	8002	Systems / Program Administrator or Applications / Systems Support Professional
Human Resources	9000	Human Resources Manager
	9001	Human Resources Generalist
	9002	Human Resources Coordinator
	9003	Payroll
	9004	Manager, Health & Safety

Participants All organizations in the LDC sector in Ontario were invited to participate in the survey. The following forty-one (41) organizations submitted data:

- Bluewater Power Distribution
- Brantford Power Inc.
- Burlington Hydro
- Collus PowerStream Corp.
- E.L.K. Energy Inc.
- Energy+ Inc.
- Entegrus Inc.
- Enwin Utilities Ltd.
- Espanola Regional Hydro Distribution
- Essex Power
- Festival Hydro Inc.
- Fort Frances Power Corp.
- Greater Sudbury Utilities
- Grimsby Power Inc.
- Guelph Hydro Electric Systems Inc.
- Halton Hills Hydro Inc.
- Hydro Ottawa
- InnPower Corp.
- Kitchener-Wilmot Hydro Inc.
- Lakefront Utilities Inc.
- Lakeland Power Distribution Ltd.
- London Hydro Inc.
- Midland Power Utility Corp.
- Milton Hydro Distribution Inc.
- Niagara Peninsula Energy Inc.
- North Bay Hydro Distribution Ltd.
- Northern Ontario Wires Inc.
- Oakville Hydro
- Orangeville Hydro Ltd.
- Orillia Power Distribution Corp.
- Oshawa PUC Networks, Inc.
- Peterborough Utilities Group
- PUC Services Inc.
- Thunder Bay Hydro Electricity Distribution Inc.
- Utilities Kingston
- Veridian
- Wasaga Resource Services
- Waterloo North Hydro Inc.
- Welland Hydro-Electric System Corp.
- Westario Power Inc.
- Whitby Hydro Energy Services Corp.

Due to the changes in the participant mix, data values in the report can fluctuate from one year to another. Therefore, participants are reminded of these factors when comparing data from 2016 over 2015.

Participant Group Profile

All participants provided information regarding their organizational profile. The summary statistics of the participating organizations are detailed below.

The figures reported below are assessed on an "as provided" basis. Hay Group and the MEARIE Group have not independently or exhaustively verified the values presented below.

Statistic	P25	P50	P75	Average
Annual Operating Budget ($ millions, less the cost of power)	4.5	10.0	19.0	18.2
Annual Operating Budget ($ millions, including the cost of power)	37.4	102.5	172.5	139.6
Number of Employees (full time equivalent)	32	65	135	102
Number of Customers	13,516	36,280	55,433	48,529
Gross Revenue ($ millions, less the cost of power)	8.5	17.1	32.2	28.3
Gross Revenue ($ millions, including the cost of power)	41.0	109.1	198.8	151.6
Regulated Gross Revenue	97%	99%	100%	90%
Unregulated Gross Revenue	0%	1%	3%	10%

All organizations noted the fiscal year ends in December.

Analyst Note: where average is significantly higher or lower than the median of the market, this indicates a small number of observations which skew the data either high or low. For example, unregulated gross revenue average is 10%, which is substantially higher than the 1% median or 3% 75th percentile, indicating that within the top 25% of organizations there is a significant portion of unregulated Gross revenue in excess of 10% in a few organizations.

3. Salary Administration

Salary Range Adjustments – 2015, 2016 & 2017

Thirty-four (34, or 83%) organizations reported data for salary ranges while 7 (17%) indicated they did not use ranges. The most common month for adjusting salary ranges is January (over 50% of reporting organizations).

Survey participants report adjusting their salary ranges in 2015 by an overall average of 1.9% (n = 32). Excluding the 3 organizations who froze ranges (i.e., provided 0%), the overall average is 2.1%.

Survey participants report adjusting their salary ranges in 2016 by an overall average of 2.1% (n=30). Excluding 2 organizations who intend to freeze ranges this year, the overall average is 2.2%.

Survey participants report planning to adjust salary ranges in 2017 by an overall average of 2.5% (n=11). No organization has projected a freeze to salary ranges at this time.

The salary range adjustments by employee level and overall are noted in the table below:

Year	CEO (n=27)	Executive (n=27)	Director (n=24)	Management (n=29)	Professional / Technical (n=29)	Admin. (n=27)	Overall (n=32)
2015	2.0%	1.9%	1.9%	1.9%	1.9%	1.8%	1.9%
2016	2.6%	2.0%	1.8%	1.9%	1.9%	1.9%	2.1%
2017	2.9%	2.5%	2.2%	2.2%	2.2%	2.2%	2.5%

*n indicates maximum number of organizations reporting.

Base Salary Increases – 2015, 2016 & 2017

The most common timing for adjusting salaries is January (over 70% of reporting organizations grant annual salary increases in that month).

Survey participants report adjusting actual salaries in 2015 by an overall average of 2.6% (n=37).

Survey participants report adjusting actual salaries in 2016 by an overall average of 2.4% (n=34).

For 2017, survey participants reported projected average salary increases of 2.2% (n=13).

The base salary adjustments by employee level are noted in the table below.

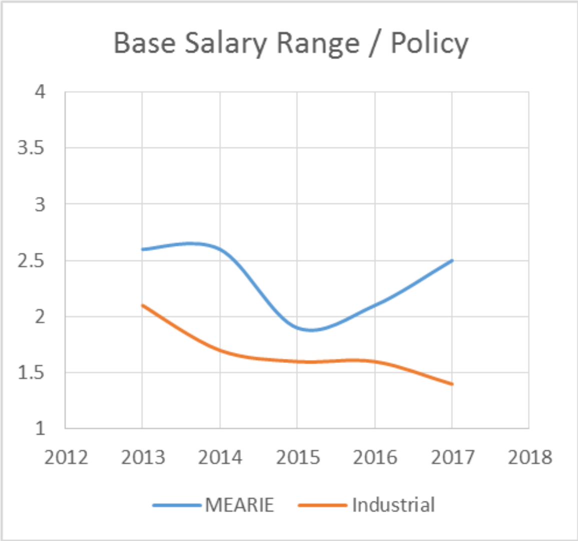
Year	CEO (n=29)	Executive (n=24)	Director (n=22)	Management (n=33)	Professional / Technical (n=28)	Admin. (n=27)	Overall (n=37)
2015	3.2%	2.1%	2.5%	2.3%	2.7%	2.0%	2.6%
2016	2.7%	2.2%	2.2%	2.3%	2.2%	2.1%	2.4%
2017	2.2%	2.2%	2.2%	2.2%	2.3%	2.3%	2.2%

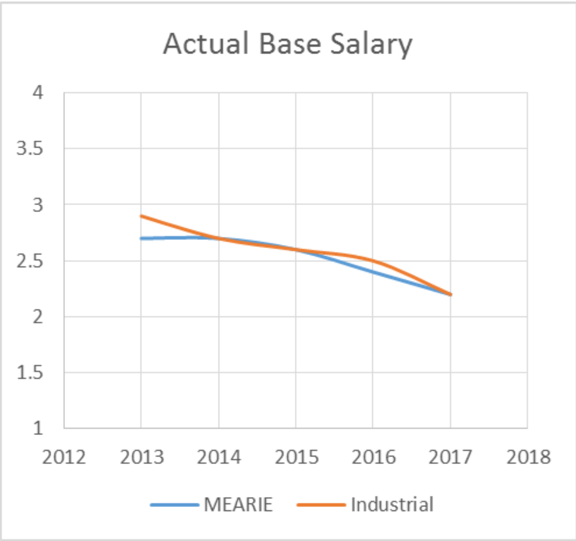
*n indicates maximum number of organizations reporting.

Salary Trends

Hay Group compiles an annual compensation forecast survey across Canada, with over 500 participants annually.

The graph below depicts how the overall Canadian all-industrial organization market has tracked from a range and actual salary perspective versus The MEARIE Group Management Salary Survey trend information over the past 5 years.





Generally, local distribution companies track very close to the all-industrial market for actual salary adjustments; generally within 0.2 percentage points. Local distribution companies track above the all-industrial market for salary range adjustments by 0.3 – 1.1 percentage points.

The differential between actual base salary increases and salary range adjustments among local distribution companies is generally small, this year the average differential is 0.3 percentage points. The average differential among industrial organizations is 0.8 percentage points.

This indicates that industrial organizations may be allocating greater portions of salary budgets to differentiation by merit, and enabling high performers to perhaps be paid above job rate and/or moving people through the range faster. That is, industrial organizations are likely increasing their overall compa-ratios, whereas LDCs are generally maintaining or movement through range is very conservative.

Incentive Programs

a. The majority of organizations (28 of 41 or 68%) indicated that they offer short term incentive pay to at least some of their employees.
   - Seventeen (17) of the organizations indicated that all employee groups participated in STI.
   - Eleven (11) organizations have STI plans for designated senior management and/or executives that do not extend to non-management staff.

b. Twenty (20) of the twenty-eight (28) organizations who offer short term incentive pay provided information about their incentive plans. Weighting of performance factors (corporate versus individual versus team/department performance) in the determination of individual bonus payments:
   - The average plan mix, by employee level, is provided in the table below.
   - Typical plan mix is a combination of corporate and individual metrics with a heavier weighting on corporate for senior management and/or executives and a heavier weighting on individual metrics for non-management staff.
   - For example:
     - The most common CEO incentive plan is 80% Corporate, 20% Individual
     - The most common Director plan is 60% Corporate, 40% Individual
     - The most common Admin plan is 20% Corporate and 80% Individual

Performance Factor	CEO	Executive	Director	Management	Professional / Technical	Admin.
Corporate	67.5%	59.8%	53.6%	42.7%	46.3%	42.0%
Team / Department	5.0%	28.0%	22.5%	26.4%	*	*
Individual	35.4%	38.8%	43.6%	53.9%	56.1%	60.2%

NOTE: As organizations are counted for each response, weightings will not add up to 100%.

**Indicates insufficient data to report.*

Incentive Programs (continued)

Threshold Bonus Payouts

Formulaic or "target based" bonus programs typically do not pay out until a minimum level of performance (corporate, team and/or individual) has been achieved (i.e., if the threshold performance is not achieved, there is no pay out). Once this threshold performance has been achieved, incentive plans will pay out a minimum level of bonus; pay out levels typically then increase as performance / results increase, up to a "target" bonus rate when performance goals have been "met".

Twelve (12) of the twenty-eight (28) organizations with incentive plans reported that they define minimum levels of performance required before any bonuses are generated. The typical bonus rate at the threshold performance is set at 50% of "target" bonus.

Maximum Bonus

Bonus programs are often designed such that there is a maximum level of payout. For example: if a position has a 10% bonus and the maximum payout is 200%, or 2x, then the maximum amount the employee can achieve regardless of performance (i.e., how much targets are exceeded by), is 20% of their current base salary.

The average maximum bonus is provided by employee level in the table below, though the typical bonus pay maximum is 100% of target.

Maximum Bonus Payout %	CEO (n =15)	Executive (n =13)	Director (n =11)	Management (n =16)	Professional / Technical (n = 9)	Admin. (n =9)
Average	1.2	1.2	1.2	1.1	1.2	1.2

In the broader market, it is more common to find higher maximum bonus levels (as a % of target) at higher levels of the organization, to reflect the greater influence on organizational performance that more senior roles are perceived to have.

Special (Project) Bonuses

Organizations were asked if they provide any project bonuses for participation in key / special projects, paid on successful achievement of specific milestones and/or on completion of the project, separate and distinct from annual incentive plans.

Three (3) organizations reported providing such bonuses. There is insufficient data to provide the average value as no employee level has at least three data observations.

4. Benefit Policies

Car Benefit

The majority of organizations (34 of 41 or 83%) provide a car benefit to some level of employee.

The tables below summarize the value of car benefits, by position, where provided. An asterisk (*) indicates insufficient data to report:

		Company Owned Car (Value)	Monthly Lease Payment	Car Allowance (monthly)
CEO	P75	*	*	838
	P50	42,500	*	750
	P25	*	*	600
	Average	41,999	956	738
	Number	5	3	22
Executive / VP	P75	*	*	700
	P50	*	*	510
	P25	*	*	400
	Average	36,667	*	547
	Number	3	2	13
Sr. Management / Director	P75	*	*	517
	P50	*	*	475
	P25	*	*	350
	Average	*	*	432
	Number	2	0	8

Four (4) organizations reported providing a car benefit to specified positions below Senior Management. Specifically, three (3) organizations provide use of a company-owned vehicle and one (1) provides a vehicle allowance.

Mileage

The market statistics for mileage rates provided to employees as reimbursement for personal vehicle use are detailed in the table below.

N = 38	Mileage Reimbursement (¢ per km)
P75	54
P50	53
P25	49
Average	51

The most frequently reported mileage rate (11 organizations) is 54 cents per kilometer; the next most frequent reported rates are 55 cents per kilometer (4 organizations).

Perquisites

Club Memberships – Fitness

Seventeen (17) organizations reported providing a subsidy for fitness club fees. The typical policy is to provide a reimbursement of a fixed dollar amount per year. For all organizations, the same policy and maximum reimbursement applies regardless of job level.

N = 17	Maximum Reimbursement per year
P75	300
P50	200
P25	150
Average	224

Club Memberships – Social

None of the organizations reported having a separate policy / program for reimbursement of social club fees.

Perquisites (cont'd)

Health Spending Account

Eleven (11) organizations reported providing a Health Spending Account (i.e. discretionary spending within a defined range of services / benefits).

Of the eleven (11) organizations, seven (7) provide the same funding for all jobs levels while four (4) differentiates by job level.

	CEO	Executive	Director	Management	Professional / Technical
P75	950	1,025	1,000	875	1,000
P50	525	475	500	400	400
P25	363	363	375	313	300
Average	720	810	650	555	569
Number	10	10	7	10	9

2nd Opinion Medical Advice

Three (3) organizations in the survey reported having a separate policy / program for this benefit.

Personal Financial / Legal Counseling

Four (4) organizations reported that financial and legal counseling is available via their Employee Assistance Program, which is provided to all employees. One (1) of these organizations reported a maximum dollar value.

Executive Medical Plan

Four (4) organizations reported providing enhanced medical coverage for executive levels only. Three (3) organizations reported a maximum dollar value, with an average maximum value of $1,336.

Perquisites (cont'd)

Personal Computer / Cell Phone / Internet

Thirteen (13) organizations provided information regarding policies and practices related to computers and internet.

The most common policies/practices are:

- Low / no interest rate loans to purchase computer equipment for personal / home office use.
- Provision of laptops for particular levels of employee, in addition to office desktop, to allow for mobile work (note: may be a perquisite if personal use of computer is allowed, but not a perquisite if for business use only).
- Reimbursement for cell phone and/or home internet connection for selected employees (either full reimbursement or 50% reimbursement were both provided in the market place).
- Cash allowance intended to cover cell phone and/or internet service.

The value of these benefits varies dramatically by level within organizations and between organizations; the data does not lend itself to reporting of the value of typical practices.

Other Perquisites

Other programs / practices reported, by eight (8) organizations, include:

- Reimbursement of dues / fees for professional associations such as Engineers (P.Eng) and Accountants (CGA/CMA/CA).
- Provision of an Employee Assistance Program.

Enhanced Life Insurance Coverage for Senior Officers

Organizations were asked if, for senior level jobs, there was additional, employer paid, life insurance coverage. For example, if the typical life insurance plan was 1.5x employee salary, was this enhanced to above 1.5x to some greater number such as 2x, or even 3x, for senior level jobs.

Seventeen (17) organizations provided information about their basic / standard life insurance coverage where the typical coverage is 2x annual salary (average coverage of 1.65x). Enhanced benefits are provided by seven (7) organizations, where senior roles receive coverage at an average of 1.87x annual salary.

Vacation Entitlement

Forty (40) organizations provided the number of years of service required by various levels of employee in order to be entitled to a certain number of weeks of vacation.

The following table below details the range, average and typical (i.e., most common) number of years of service required per weeks of entitlement.

Several organizations noted that for executive level jobs, vacations are typically negotiated versus following a schedule for entitlement.

	2 weeks	3 weeks	4 weeks	5 weeks	6 weeks +
CEO					
Range	*No range*	*Start* - 6	*Start* - 15	*Start* - 18	5 - 28
Average	*Start*	3	6	13	22
Typical	*Start*	3	9	17	25
sample	n = 16	n = 23	n = 31	n = 32	n = 31
Executive / VP Level					
Range	*No range*	*Start* - 4	*Start* - 10	3 - 18	8 - 28
Average	*Start*	2	6	14	23
Typical	*Start*	3	9	17	25
sample	n = 15	n = 23	n = 29	n = 29	n = 29
Director Level					
Range	*No range*	*Start* - 6	*Start* -15	8 - 18	15 - 28
Average	*Start*	2	7	15	23
Typical	*Start*	3	9	17	25
sample	n = 17	n = 29	n = 36	n = 34	n = 34
Manager Level					
Range	*No range*	*Start* - 4	*Start* - 10	8 - 18	15 - 28
Average	*Start*	2	7	15	23
Typical	*Start*	3	9	17	25
sample	n = 16	n = 32	n = 36	n = 34	n = 33
Professional Level (n = 37)					
Range	*No range*	*Start* - 6	*Start* - 15	8 - 18	15 - 28
Average	*Start*	2	7	15	24
Typical	*Start*	3	9	17	25
sample	n = 20	n = 33	n = 36	n = 34	n = 34

Unused Vacation

Organizations provided information about their policies and practices with regard to vacation time that was not fully utilized in the year in which it was earned.

Policy Regarding Carry Over	Number	%
Unused vacation entitlement at year end is paid out (vacation pay adjustment) – no carry over.	2	5%
Any/All unused vacation entitlement may be carried-over with no restrictions.	4	11%
Unused vacation entitlement may be carried over, subject to maximum total accumulated balance.	12	32%
A maximum amount of unused vacation may be carried over.	20	50%
No unused vacation may be carried over	1	3%
Total	39	100%

Maximum Number of Days to Carry Over (n = 24)	Number of Days
Range	3 - 15
Average	7.4
Typical	5

Time Limit for Utilizing Carried-Over Vacation Time	Number
No limit	9
One Year	8
Six Months or less	19
Total	36

Note:

Some organizations reported variations to the above policies such as:

- Seven (7) of the thirty-one (31) organizations who have a maximum amount of days that can be carried over specified it as either one year entitlement or a portion of the years entitlement.
- Exception policies where workload or special projects caused the employee to be unable to fully utilize vacation time, or where carry forward beyond standard policy is regularly allowed but must be approved by senior management.
- Cash out policies where some vacation time may be paid out instead of being carried over.
- Differences by vacation eligibility, such as carrying over 10 days if eligible for up to 3 weeks' vacation but 20 days if eligible for 4 weeks' vacation.

Educational Assistance / Reimbursement

Twenty participating organizations (20) provided details with regards to education assistance / reimbursement policies ranging from eligibility criteria to pay back provisions. There are a wide variety of types of programs and reimbursement rates. Key highlights are provided below:

- Seventeen (17) organizations stated that is education assistance / reimbursement; though typically there are limiters such as education or training courses which must be job related, and are subject to managerial approval.
- Three (3) organizations stated that there is no formal policy, however, approval for educational assistance or reimbursement happens regularly and is on a case by case basis.
- Five (5) organizations provided an annual reimbursement maximum, the average is $1,600 and the median is $1,500.
- Two (2) organizations provided a lifetime reimbursement maximum, there is insufficient data to report average/median.
- Payback provisions were provided by twelve (12) organizations. The average time to not trigger any pay back provision is 2.6 years, the median is 2.5 years. The range of time is between 90 days to 5 years. Eight (8) organizations noted they have some form of partial payment plan for leaving within a designated time period after completion of education. For example, if the employee leaves after 4 years, they will not be asked for any repayment; if the employee leaves in 2 years, they will be asked for 50% pay back.

5. Benchmark Position Survey Results

Survey Results

This section reports the information collected in aggregate values for each benchmark position. The values reported in this table reflect “All Ontario” data in that the data for all organizations matching to the position are included (regardless of size and geographic location).

Additional summaries, on a job by job basis, are provided in the accompanying “Addendum”.

Detailed analysis, with expanded statistical data (i.e., including P25 and P75 data points) as well as analysis of survey results by geographic region, by customer base and by revenue, are reported in the Excel files accompanying this report.

The MEARIE Group

2016 Management Salary Survey
Of Local Distribution Companies

ALL ORGANIZATIONS

		Job Matches			Compensation Design						Actual Compensation				
Code	Survey Job Title	Sample Statistics		Hay Points	Salary Range Minimum	Job Rate	Salary Range Maximum	Target Bonus % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
		# Orgs	# Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
0000	President & CEO	34	34	1192	148,500	185,000	197,900	25%	195,700	211,400	185,100	187,400	22%	205,500	219,600
0001	Chief Operating Officer (COO)	11	11	864	130,400	144,000	160,200	15%	157,800	174,700	151,500	149,900	11%	161,700	171,000
0002	Head of Operations and/or Engineering	20	25	872	118,700	136,900	148,900	15%	140,800	153,100	138,600	138,500	11%	142,400	148,500
0003	CFO / Head of Finance	29	29	830	121,200	141,800	148,100	15%	149,600	158,800	141,900	142,900	13%	149,900	163,100
0004	Head of Customer Service	11	11	702	108,600	127,700	146,000	14%	137,800	143,700	127,500	135,400	10%	147,500	146,300
0005	Head of Regulatory Affairs	5	5	677	111,200	120,500	138,600	14%	132,600	147,700	137,400	141,100	*	150,800	155,300
0006	Head of Human Resources	13	13	677	108,600	123,600	131,500	15%	142,200	142,400	127,900	129,300	14%	144,900	144,900
1000	Executive Assistant	25	32	245	59,500	70,100	77,500	5%	72,500	72,400	72,600	72,300	4%	74,800	75,700
1001	Administrative Assistant	12	21	184	51,400	59,100	63,600	6%	59,100	62,100	64,300	62,800	4%	64,300	63,900
2000	Director Engineering	10	11	702	104,100	130,700	137,000	10%	136,100	138,600	133,100	128,800	11%	140,100	137,600
2001	Engineering Manager and/or Distribution Engineer	19	25	588	88,400	103,900	115,400	8%	109,100	111,000	105,900	106,300	5%	110,800	109,800
2002	Project Engineer	9	11	417	71,800	85,300	91,500	*	87,100	87,200	84,500	83,500	*	84,500	84,900
2003	Supervisor Engineering	13	16	421	80,900	92,600	101,100	6%	94,600	96,700	92,600	92,000	3%	94,500	95,100
2500	Director Operations	8	9	732	108,300	135,400	135,900	10%	141,300	139,200	132,700	128,300	10%	138,200	135,500
2501	Manager Operations	20	21	516	92,600	104,700	116,800	7%	109,800	110,600	107,200	108,500	6%	111,200	116,900
2502	Manager Control Centre	4	4	534	92,800	111,000	114,800	9%	120,000	120,200	110,400	110,600	*	121,500	119,700
2503	Supervisor Control Centre	8	8	436	79,900	94,100	101,100	5%	96,300	95,600	97,600	97,400	*	97,600	99,300
2504	Supervisor Protection and Control	5	5	496	83,400	97,900	104,200	*	99,700	104,800	99,700	98,600	*	99,700	103,400
2505	Supervisor Station Maintenance	7	7	496	83,100	99,700	103,300	*	99,700	106,300	101,100	105,900	*	103,300	109,700
2506	Line Supervisor	26	67	366	82,700	95,900	101,100	5%	96,600	98,500	97,000	97,200	4%	98,600	103,000
2507	Manager Meter Department	8	8	551	95,700	105,900	110,700	8%	116,200	117,200	109,300	108,700	6%	118,700	115,100
2508	Supervisor Meter Department	8	11	406	83,400	93,700	96,700	7%	98,300	98,200	96,900	96,600	6%	101,700	100,200
3000	Director Supply Chain Management	1	1	*	*	*	*	*	*	*	*	*	*	*	*
3001	Manager Procurement and/or Inventory and/or Facilities and/or Fleet	13	13	393	82,400	95,600	103,600	7%	101,400	98,900	97,300	97,800	6%	101,500	101,700
3002	Supervisor Stores/Inventory/Warehouse	5	8	342	70,100	81,400	88,500	*	87,100	86,300	83,200	85,500	*	87,700	88,200

The MEARIE Group

2016 Management Salary Survey
Of Local Distribution Companies

ALL ORGANIZATIONS

		Job Matches			Compensation Design						Actual Compensation				
Code	Survey Job Title	Sample Statistics		Hay Points	Salary Range Minimum	Job Rate	Salary Range Maximum	Target Bonus % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
		# Orgs	# Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
4000	Controller or Director Finance	14	14	588	92,700	109,500	115,000	7%	113,600	116,100	113,900	111,500	8%	120,300	117,400
4001	Manager Accounting	14	14	479	85,900	101,700	116,600	8%	106,200	106,400	95,800	98,100	6%	98,300	102,700
4002	Manager Risk Management	1	1	*	*	*	*	*	*	*	*	*	*	*	*
4003	Supervisor Accounting	6	7	377	75,800	91,100	96,800	6%	91,100	94,200	94,200	91,600	4%	95,200	95,600
4004	Financial or Business Analyst	11	12	342	73,100	86,900	92,400	5%	88,900	90,000	83,800	85,000	4%	86,900	87,700
4005	Accountant	9	14	332	67,100	79,500	83,700	4%	79,600	80,700	79,500	76,900	2%	79,500	77,900
5000	Director Customer Service	3	3	*	*	*	*	*	*	128,200	*	116,400	*	*	123,200
5001	Manager Customer Service and/or Billing	20	20	479	81,200	92,600	100,300	8%	94,300	95,800	95,500	93,100	6%	97,900	99,800
5002	Supervisor Customer Service and/or Billing and/or Collections	21	31	353	70,800	86,800	89,800	5%	87,600	86,600	82,200	84,200	4%	85,600	86,500
5500	Director Communications	3	3	*	*	*	*	*	*	112,200	*	106,300	*	*	115,400
5501	Manager Communications	8	8	342	75,800	83,100	89,200	6%	87,400	87,600	84,400	83,900	5%	87,700	87,000
6000	Director Regulatory Affairs	4	4	666	117,900	132,900	143,100	15%	152,800	153,800	138,000	136,000	14%	161,800	153,400
6001	Manager Regulatory Affairs	11	11	393	81,200	92,600	96,000	8%	95,500	96,400	92,400	94,000	8%	95,500	97,900
6002	Regulatory Accountant	12	13	337	69,600	81,800	94,500	7%	82,500	85,300	81,800	84,000	5%	83,800	86,700
7000	Settlement or Rate Analyst	5	7	342	74,300	89,800	92,100	*	89,800	90,700	89,800	88,300	*	91,700	90,900
7001	Director or Officer, Conservation and Demand Management	7	7	805	109,900	127,700	139,100	13%	141,100	144,800	122,400	124,600	17%	139,900	148,600
7002	Manager Conservation & Demand/Marketing	12	12	393	77,900	90,900	92,800	9%	93,000	88,800	89,900	86,400	8%	95,700	93,200
8000	Director Information Systems	9	9	677	108,600	126,100	132,100	14%	138,700	135,100	128,200	126,200	13%	139,400	138,700
8001	Manager Information Systems and/or Security	14	18	479	86,000	96,100	103,200	5%	99,100	100,800	97,500	98,000	5%	101,100	101,500
8002	Systems/Program Administrator or Applications/Systems Support Professional	15	19	332	68,700	80,100	89,900	5%	80,100	83,700	88,500	83,800	4%	93,100	90,100
9000	Human Resources Manager	5	5	479	77,900	92,100	98,900	*	92,100	95,200	97,200	89,800	*	97,200	90,900
9001	Human Resources Generalist	9	11	289	62,600	73,600	80,900	5%	75,800	79,800	79,400	77,900	3%	79,400	81,100
9002	Human Resources Coordinator	5	5	245	61,900	76,100	76,100	6%	79,400	77,000	68,200	70,500	*	71,100	73,000
9003	Payroll	12	12	245	60,600	71,400	79,500	4%	74,200	74,500	75,100	73,400	3%	77,000	75,500
9004	Manager, Health & Safety	16	16	479	83,300	97,600	107,700	7%	99,100	103,700	98,900	100,000	5%	102,400	104,900

APPENDICES

A. Survey Methodology

A brief profile was developed for each benchmark position. These profiles were incorporated into a survey package and distributed to each participant along with a data submission spreadsheet requesting data on survey benchmark positions, as well as the organization's profile and selected salary administration & benefits policies.

Participants matched their jobs to the profiles and provided data for each position, where applicable. For each position where an organization submitted more than one match, the data were aggregated and an average figure was used for that organization. By using this methodology, all organizations carry equal weighting, and no one single organization excessively influences the market statistics by virtue of the size of its employee population.

Once the completed surveys were returned to Hay Group, participants were contacted for data verification as necessary. Hay Group also initiated a number of follow-up actions to clarify information provided by the participants. All of the matches submitted by the participants were reviewed by Hay Group to determine their appropriateness versus the job profiles and the market. If deemed inappropriate, the matches, or outlier data, were removed from the survey results.

Where possible, organization charts or details regarding reporting relationships were provided to Hay Group to enable understanding of the roles. From the job match information, plus a review of organization charts and other contextual information provided, Hay Group has estimated at which Hay Reference Level each organizations' roles fall to facilitate point-based comparisons.

B. Definitions – Compensation Elements

Salary Range

Minimum	The lowest salary/rate that the organization is prepared to pay for an incumbent in the position. May be the starting salary for inexperienced/non-qualified hire.
Job Rate / Control Point	Typically the midpoint of the salary range, intended to reflect the salary the organization is prepared to pay for sustained competent performance by a fully trained / qualified incumbent.
Maximum	The highest point in the salary range (or step progression). Note: might be the same as "job rate".
Short Term Incentive	*Short Term Incentive (STI) refers to any incentive arrangement designed to reward an individual for performance/results achieved over a performance cycle/period of up to one year.*
Target	Target bonus is the level of award (either a % of salary or a fixed dollar amount) that an employee in this position would expect to receive if all corporate, team and individual performance goals are "met" (as planned). This rate/amount is often communicated to employees as part of the incentive/bonus plan design, e.g. "the target bonus for jobs in grade/band 6 is 8% of salary".
Discretionary	Discretionary plans have no target bonus rate and pay out at the end of the year at the discretion of executive/board.
Current Salary	The amount paid for work performed on a regular, ongoing basis. Does not include variable bonus or incentive payments, sales commissions, shift premiums, or overtime payments.
Actual STI (Paid)	*Total of all STI awards paid to the incumbent(s) for performance/results over the latest completed fiscal year.* May be paid during the year or after year end. (Note: recorded and reported on an annual basis)

C. Definitions – Statistical Elements

Market data are reported using the following statistics:

	Definition	Reporting Requirement (# of Observations Necessary to Report)
P90	90th percentile If all observations were sorted and listed from highest/largest to lowest/smallest, 10% of the observations would fall above the 90th percentile and 90% would fall below	**11**
P75	75th percentile If all observations were sorted and listed from highest/largest to lowest/smallest, 25% of the observations would fall above this value and 75% would fall below	**7**
P50	50th percentile, also referred to as "median" If all observations were sorted and listed from highest/largest to lowest/smallest, 50% of the observations would fall above this value and 50% would fall below	**4**
P25	25th percentile If all observations were sorted and listed from highest/largest to lowest/smallest, 75% of the observations would fall above this value and 25% would fall below	**7**
P10	10th percentile If all observations were sorted and listed from highest/largest to lowest/smallest, 90% of the observations would fall above this value and 10% would fall below	**11**
Average	The arithmetic mean of all values, calculated by adding up all of the values and dividing by the number of observations	**3**

D. Benchmark Position Profiles

Job Title	Description
President & CEO	Directs the development of short and long term strategic plans, operational objectives, policies, budgets and operating plans for the organization, as approved by the Board of Directors. Establishes an organization hierarchy and delegates limits of authority to subordinate executives regarding policies, contractual commitments, expenditures and human resource matters. Represents the organization to the financial community, industry groups, government and regulatory agencies and the general public.
Chief Operating Officer (COO)	Highest ranking operations position. Reporting to the President/CEO, directs the operational elements of the organization, could include operations & engineering, customer services, metering and information technology. Develops the short and long term strategic plans, directs the development of operational objectives, policies, budgets for his/her areas of accountability. The position reports directly to the President/CEO.
Head of Operations and/or Engineering	Highest ranking operations/engineering position. Reporting to COO or President. Directs both the operations and engineering functions. Develops the short and long term strategic plans, formulates and implements plans, budgets, policies and procedures to facilitate and improve processes. Establishes clear controls, objectives and measures to ensure safe and appropriate delivery of power and power related services. Evaluates the feasibility of new or revised systems or procedures and oversees operations and engineering to ensure compliance with established standards.
CFO / Head of Finance	Highest ranking financially-oriented position within the company. Reporting to the President &CEO, this strategic role plans directs and controls the organization's overall financial plans, policies and accounting practices and relationships with lending institutions, shareholders and the financial community in mid to large organizations. Provides advice and guidance for the Board of Directors on financial matters. May direct such functions as finance, general accounting, tax, payroll, customer billing, regulatory affairs, and information systems and may be responsible for Administration functions. Normally possesses a CA, CMA or CGA designation.
Head of Customer Service	The highest-ranking customer service position in the utility. Provides direction for all departmental activities, services and practices, including customer care/call centre, billing, credit and collections. Accountable for the development, implementation and integration of all customer service related activities to achieve a competitive advantage through customer driven initiatives and strategies. Directs and oversees the implementation of customer service standards, policies and procedures; manages and coordinates budgets.
Head of Regulatory Affairs	Represents the organization on quality and regulatory matters before government agencies and conformity assessment bodies including providing of evidence, regulatory filings, supporting analyses, position papers, interrogatory responses, etc. Keeps abreast of on-going developments in regulatory practices affecting electrical distribution utilities. Ensures that regulatory information is disseminated throughout the organization in a timely and effective manner. Is responsible for the filing of written communications and regulatory submissions to government agencies (OEB) and conformity assessment bodies (IMO). Generally reports to President & CEO or a senior executive.
Head of Human Resources	The highest-ranking human resources position in the organization. Provides direction, support and alignment of organization-wide Human Resources practices and systems with the business in terms of mission, vision and the strategic imperatives. Ensures that existing needs and future demands of internal customers are met through a cost effective and efficient HR services. Directs HR management and staff in the development and implementation of Human Resources strategy, policies and programs covering employment, negotiations & labour relations, training, compensation, organization development, performance management, benefits and may include health & safety. Provides coaching and counsel to the executive and Board of Directors.

Administration

Executive Assistant	Performs advanced, diversified and confidential administrative duties requiring broad knowledge of organizational policies and practices. Initiates and prepares correspondence, reports, either routine or non-routine. Screens telephone calls and visitors and resolves routine and complex inquiries. Schedules appointments, meetings and travel itineraries. In some cases, may have responsibility for routine HR and administrative services. Records, prepares and distributes minutes of meetings, including Board of Director minutes. Reports to the President & CEO and may provide support to other executives.
Administrative Assistant	Performs advanced, diversified and confidential administrative duties for executives and/or senior management, requiring broad and comprehensive experience and knowledge of organizational policies and practices. Prepares correspondence, reports, either routine or non-routine. Screens telephone calls and visitors and resolves routine and complex inquiries. Schedules appointments, meetings and travel itineraries. Reports to a senior executive or executive team.

Engineering

Director Engineering	Plans and directs the overall engineering activities and engineering staff of the organization. Formulates and implements plans, budgets, policies and procedures to facilitate and improve processes. Coordinates the creation, development, design and improvement of the organization's projects and products in conformance with established programs and objectives. Oversees plans, resources and budgets of the department aligned with business strategy.
Engineering Manager and/or Distribution Engineer	Supervises and directs the work of an engineering division such as distribution, line design, transmission planning, distribution planning and/or civil engineering. Responsible for engineering work involving a wide scope of assignments. Handles personnel coordination and issues of the division, prepares estimates, specifications and designs, including the supervision, planning and scheduling of work within the division – Requires a P. Eng. OR Supervises engineering technicians or service technicians. Directs and coordinates the activities, schedules and projects of the construction and maintenance group of those involved with the distribution of electrical power from transformer substations, construction and maintenance of distribution systems. Consults with other department management on plant design, construction and maintenance. Prepares monthly operating reports, budget estimates, and work and materials specifications. Reviews and approves material requisitions, work authorizations and drawings for facilities. Requires a P. Eng.
Project Engineer	Non-supervisory position. Directs and coordinates activities related to utility engineering project work, such as smart grid systems, renewables, large utility projects, asset renewal, etc. Requires a P. Eng.
Supervisor Engineering	Supervises a small technical work group which may include CAD operators and/or engineering technicians. Coordinates the development and maintenance of engineering and construction standards and systems (GIS, AM/FM, CAD). Organizes, stores and maintains the integrity of hard copy file records, digital formats and mapping standards. Normally requires a C.E.T. or A.Sc. T. Typically reports to an engineering manager.

Operations

Director Operations	NOT the head of function. Plans and directs all operations functions (no engineering responsibility), of the utility. Formulates and implements plans, budgets, policies and procedures to facilitate and improve processes and establishes clear controls, objectives and measures to ensure safe and appropriate delivery of services and clarity of roles and responsibilities. Evaluates the feasibility of new or revised systems or procedures and oversees operations to ensure compliance with established standards.
Manager Operations	NOT the head of function. Supervises, co-ordinates, directs, schedules and controls the construction, maintenance and personnel of the division, including budgets, transportation, equipment and material requirements and fleet management. Division responsibilities include construction, maintenance and repair of all overhead transmission, overhead and underground distribution and may include coordination of tree trimming for geographical area assigned to the division. In smaller utilities, a professional engineer may fill this role.
Manager Control Centre	Supervises, co-ordinates, directs, schedules and controls the control centre and technical staff. Provides leadership in the planning and coordination of the control centre relative to safety, reliability and control of the distribution system. Is responsible for budgets, and the direct operations of the control centre approving system outages, switching and maintenance requirements to maintain and improve system reliability.
Supervisor Control Centre	Directs and supervises control centre technical staff. Provides planning and coordination of control centre scheduling and maintenance required for the safe, reliable operation and control of the distribution system, including the authorization of the operation of system devices, equipment and control access to electrical plant and substations. Approves and coordinates system outages and switching as required for maintenance and system reliability. Oversees power interruptions and emergencies with dispatch staff to affect corrective measures for isolation, emergency repairs and restoration purposes. Monitors feeder load profiles.
Supervisor Protection and Control	Responsible for the management of all Protection & Controls activities related to the installation, maintenance and commissioning of: Protective Relaying Schemes and Station Automation Systems; SCADA System, Visual Display System and Remote Terminal Units; Operations Ethernet and system-wide Area Communications Networks; Distribution Automation Systems, Sectionalizing Devices and Remote Supervisory Controlled Devices. Prepares and administers reports, budgets, Policies and Procedures, record keeping systems.
Supervisor Station Maintenance	Responsible for the planning, coordinating both maintenance and installation of substations, as well as ensuring reliability of the underground plant, through testing and troubleshooting. Supervises, coordinates and schedules the activities of Station Maintenance Electricians and Protection and Control Technicians, Reviews work assignments, daily logs, reports and orders. Co-ordinate crews and plan jobs, assigns work per shift, long-term work and shift coverage to ensure the smooth flow of routine work and that all shifts are covered.
Line Supervisor	Coordinates and directs the lead journey person and/or crews in the construction and maintenance of distribution lines and equipment (overhead and/or underground). Works with lead journey person to develop plans and schedules required in directing and assigning a crew or crews of skilled trade staff in performing construction, maintenance and operation of the distribution system lines in a safe and efficient manner. Supervises and coordinates subcontractors engaged in planning and executing work procedures, interpreting specifications and managing construction.
Manager Meter Department	Supervises the overall operations of the Meter department, prepares budgets, directs the purchase and maintenance of equipment and technology related to the department. Provides direction on the supervision of meter staff, the assignment of work and productivity of staff. Supervises the work related to interactions with electronic meter programming and interaction with/or the operation of the MV90 or similar data collection systems.

Supervisor Meter Department	Responsible for overall operation of the Meter department, including operations, budgeting and supervision of meter technicians or other operations staff. Assigns, monitors and inspects the daily work and productivity of the staff in metering operations to ensure timely delivery of services, maintenance of equipment and identification of issues. Develops work plans for the department that include supervising meter re-verification, new meter installs, record maintenance and monitoring of meter maintenance, damage, reporting and theft issues. Ensures compliance with technical standards for equipment. Responsible for electronic meter programming and interaction with/operation of an MV90 or similar data collection system.

Supply Chain / Procurement

Director Supply Chain Management	Responsible for the overall operation of the Procurement, Inventory, Fleet and/or Facilities programs and initiatives in the organization. Formulates and implements plans, budgets, policies and procedures to facilitate and improve processes and establishes clear controls, objectives and measures to ensure safe and appropriate delivery of services and clarity of roles and responsibilities. Oversees the establishment of user service level agreements, and provides contract management expertise and acts as a resource for contract negotiation, review and approval. Directs the effective capital acquisition and maintenance of the corporate fleet and/or directs the effective maintenance and capital investment of the organizations facilities and assets.
Manager Procurement and/or Inventory and/or Facilities and/or Fleet	Responsible for all purchasing and/or inventory and/or facilities and/or fleet for all areas of the utility. Negotiates vendor agreements and manages the tender process. May also be responsible for stores and inventory control in the warehouse. Is responsible for budgets, policies and procedures and directs the work of the purchasing or buyers and/or stores and/or facilities and/or fleet personnel. Works with the organization in setting partnership relationships to understand and meet the needs of the organization, its operations and risk associated with the effective and efficient operations of the company.
Supervisor Stores/Inventory/ Warehouse	Supervises inventory control, records and stores operation. Orders material to maintain on-hand quantities with procurements approval. Responsible for testing safety equipment, i.e., hoses, blankets, gloves, etc., small tool and equipment repair and reconditioning. Assists procurement department in the sale of obsolete equipment and material.

Accounting / Finance

Controller or Director Finance	NOT the head of function. Responsible for all financial reporting, accounting and record keeping functions. Directs the establishment and maintenance of the organization's accounting and finance principles, practices and procedures for the maintenance of its fiscal records and the preparation of its financial reports. Directs general and property accounting, cost accounting and budgetary control. Appraises operating results in terms of costs, budgets, operating policies, trends and increased profit opportunities. Reports to a CFO/VP Finance.
Manager Accounting	Manages the general accounting functions and the preparation of reports and statistics reflecting earnings, profits, cash balances and other financial results. Formulates and administers approved accounting practices throughout the organization to ensure that financial and operating reports accurately reflect the condition of the business and provide reliable information. Reports to Controller/Director Finance or CFO/VP Finance.

Manager Risk Management	Responsible for risk management activities including cash flow management, credit facilities management, insurance and support for credit and collection policies throughout the corporation. May be responsible for ensuring that cash liquidity risk is managed in an appropriate fashion such that bank account balances are sufficient to meet operational, capital expenditures and debt servicing requirements while minimizing short-term borrowings or surplus investing. Provides leadership in the developing new and refining existing risk management policies to respond to changes in risk tolerances and business conditions and as financial risks are better understood in accordance with industry best practices. Reports to Head of Finance or COO or CEO.
Supervisor Accounting	Coordinates activities of the payable/receivable clerks. Supervises accounts payable and receivable transactions, entries and trial balances; responsible for the accuracy of all journal entries and reconciliation of invoices; updates credit department on account status.
Financial or Business Analyst	Conducts analysis of information for budgeting, investment and financial forecasts; applies principles of accounting to analyze past and present financial operations; estimates future revenues and expenditures; prepares budgets; develops and maintains budgeting systems; processes and prepares business transactions and reports, reconciles ledgers and sub-ledgers, cash flow projections, entry of source documents. Holds a financial designation, either CA, CMA or CGA.
Accountant	Supports the organization decisions through financial information and relevant analysis. Ensures the integrity between the CS work order systems and general ledger system is maintained. Initiate corrective measures when discrepancies occur between the systems. Collects and combines information for the decision making process by management, including financial statements and special projects as assigned (e.g. preparation of rate submission supplemental information).

Customer Service

Director Customer Service	NOT the head of function. Provides direction for all departmental activities, services and practices, including customer care/call centre, billing, credit and collections. Accountable for the implementation and integration of all customer service related activities. Oversees the implementation of customer service standards, policies and procedures; manages budgets; manages activities of CS managers and/or supervisory staff.
Manager Customer Service and/or Billing	NOT the head of function. Manages a team of customer service and/or billing representatives in providing information, receiving and responding to customer inquiries, complaints or requests. Develops and maintains customer information systems, processes and procedures including billing, credit, deposits and collections. Liaises with representatives of other organizations and customer groups to share information and resolve administrative, organizational and technical problems. Responds to elevated customer complaints. This function may also be responsible for coordinating meter installation/maintenance, residential electric service connections, and service calls.
Supervisor Customer Service and/or Billing and/or Collections	Supervises customer service representatives (billing clerks and/or collections clerks) and coordinates customer service programs within the framework of established customer service policies. Schedules and organizes staff to accommodate anticipated workflow from bill inquiries, delinquent accounts, re-connections and disconnections, customer deposits, etc. Recommends corrective steps to address customer issues and refers unique issues to manager for response.

Regulatory Affairs

Director Regulatory Affairs	NOT the head of function. Supports the VP or may represent the organization on regulatory matters before government agencies and conformity assessment bodies including providing of evidence, regulatory filings, supporting analyses, position papers, interrogatory responses, etc. Ensures that regulatory information is disseminated throughout the organization in a timely and effective manner. Is responsible for or supports the filing of written communications and regulatory submissions to government agencies (OEB) and conformity assessment bodies (IMO).
Manager Regulatory Affairs	NOT the head of function. Manages the organization's regulatory staff, programs and activities to ensure compliance. Assists the organization on quality and regulatory matters before government agencies, providing research and analyses. Ensures that regulatory information is disseminated throughout the organization in a timely and effective manner. Coordinates the filing of written communications and regulatory submissions to government agencies (OEB) and conformity assessment bodies (IMO).
Regulatory Accountant	Ensures that the accounting activities for regulatory financial reporting are in compliance with all Ontario Energy Board (OEB) policies and guidelines. Act as a key resource to provide expert advice and recommendations in the implantation of all OEB, OPA and IESO codes and regulations in order to ensure corporate compliance. Track and reconcile all OEB accounts, including business rationale for changes in balances, cost side of accounts subject to prudency review (i.e. conservation, smart meters) and the cost side of Ontario Power Authority (OPA) programs.

Conservation / Demand

Settlement or Rate Analyst	Responsible for recording, creating, analyzing, processing and reconciling metering data. Operates and administers an MV-90 or similar data collection system, downloading, validating, editing, estimating and processing interval meter-related information. Has in-depth understanding of commercial billing practices, the IMO and the OEB's Retail Settlement Code. Analyses rates using rate sensitivity models and develops appropriate rate structures, using the specific models.
Director or Officer, Conservation and Demand Management	This position is responsible for planning, coordinating, evaluating and delivering energy and water conservation and demand management programs. Develops plans for programs in accordance with the OEB's conservation and demand management code to ensure achievement of OEB mandated energy consumption and demand conservation targets.
Manager Conservation & Demand/Marketing	Responsible for managing the development and implementation of CDM initiatives as well as the marketing communications expertise and support required for the successful delivery of the company's Conservation and Demand Management (CDM) programs. Marketing communication plans may include, but are not limited to advertising, media conferences, program launch events, workshops, event displays. Liaising with, as needed, senior marketing and/or communications personnel representing organizations and groups involved in conservation and sustainability including, but not limited to, the Ontario Power Authority (OPA), the Ontario Energy Board (OEB), Ministry of Energy, municipal and regional governments, etc.

Information Systems / Technology

Director Information Systems	Accountable for operations and alignment of the Information and Telecommunication Systems with the business in terms of organization objectives and imperatives. Ensures that existing needs and future demands of internal and external customers are met through a cost effective and efficient information and telecommunication infrastructure. Oversees IS management in areas of computer operations, systems planning, design, security, programming and telecommunications. Reviews and evaluates project feasibility and needs based upon management's and business requirements and priorities. Develops departmental plans, strategy, budgets and resource requirements. Typically reports to President & CEO, or CFO.
Manager Information Systems and/or Security	Manages and directs staff in areas of computer operations, systems planning, design, security, programming and telecommunications. Develops and maintains systems standards and procedures and assigns work to department staff. Reviews and evaluates project feasibility and needs based upon management's and business requirements and priorities. Develops departmental plans, project plans, budgets and resource requirements.
Systems/Program Administrator or Applications/ Systems Support Professional	Responsible for maintenance of software systems including system analysis, programming and design, updates and changes. Makes a preliminary study of new applications and recommendations to implement them, including hardware and software. Troubleshoots and corrects problems in existing programs, other than normal problems, usually caused by changes of software or hardware.

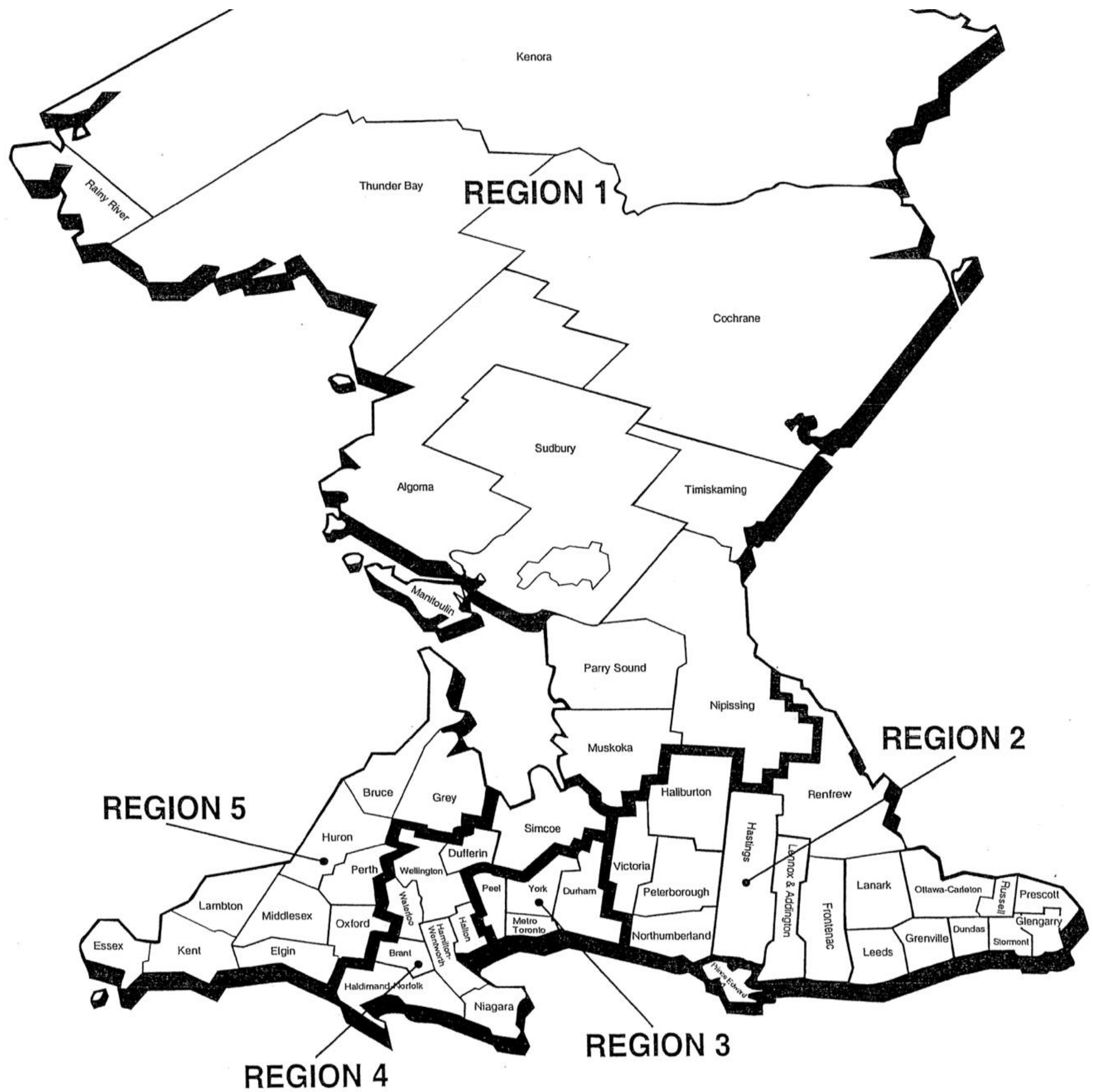
Human Resources

Human Resources Manager	NOT the head of function. Develops and implements human resources programs, including compensation, benefits, recruitment, performance management, labour relations/negotiations, training and development, assists in policy development, HR planning, record keeping or payroll etc. May supervise a team of HR professionals or support staff. Reports to a senior HR professional (Director or VP or equivalent).
Human Resources Generalist	Assists in the development and implementation of human resources policies and programs by providing support and guidance to managers and employees in the areas of compensation, labour relations, employee relations, performance management, benefits, recruitment, training and HRIS systems. Acts as a business partner to the organization in the areas of human capital. May assist in the preparation of negotiations.
Human Resources Coordinator	Administrative support to one or more functional areas of HR and/or Safety. Processes, coordinates and enters into a HRIS or other system, a variety of documents including employment applications, benefits, compensation and payroll changes and confidential employee information. Responds to routine employment questions and distributes and maintains manuals and employee program communications.
Payroll	Performs the payroll coordination and administration. Maintains the organizations internal or external payroll system. Prepares monthly requisitions for WSIB, Employee Health Tax, Receiver General, OMERS Pension and Union Dues. Administers employee pension program and provides pension calculation estimates as requested. Reconciles monthly payroll for year-end finance procedures. Prepares annual T4's and T4A's and OMERS Pension and responds to inquiries from employees and pensioners regarding the pension plan.
Manager, Health & Safety	Accountable for the development and implementation of occupational health, safety and environmental programs, including training, maintenance of safe working conditions, investigation and reporting of workplace accidents. Also identifies areas of potential risk and makes recommendations to reduce or eliminate potential accident or health hazards in compliance with government regulations.

Communications

Director Communications	Directs the development, management and execution of internal and external corporate communications strategies for the company, and marketing and public relations initiatives. Acts as the Chief Spokesperson for the organization. Leads the management and development of the corporate brand and identity. Oversees the development, production and distribution of corporate publications including, but not limited to, the annual report, customer newsletters, information brochures, bill inserts, CDM/Green marketing materials, employee newsletters and media releases. Directs the development and management of the company's external (corporate internet site) and internal (corporate intranet site) web presence and strategy. Oversees the management and execution of internal and external corporate events as well as community-relations activities such as sponsorship and donation programs.
Manager Communications	Responsible for managing the development and implementation of all customer communications initiatives as well as the marketing communications expertise and support required for the successful delivery of the company's CDM and customer communications materials/systems. Communication materials may include, but are not limited to, customer newsletters, information brochures, bill form design, employee intranet, LCD information monitors, and website communications. Working in conjunction with Regulatory Affairs, develop materials or other communication methods to communicate regulatory changes/issues that may directly impact the customer. Manages event planning for internal and external company events.

E. Regions


Kenora
Thunder Bay
REGION 1
Rainy River
Cochrane
Sudbury
Algoma
Timiskaming
Manitoulin
Parry Sound
Nipissing
Muskoka
REGION 2
Haliburton
Renfrew
Bruce
Grey
REGION 5
Simcoe
Huron
Dufferin
Perth
Wellington
Victoria
Hastings
Lennox & Addington
Lanark
Ottawa-Carleton
Russell
Prescott
Lambton
Middlesex
Oxford
Waterloo
Peel
York
Durham
Peterborough
Frontenac
Glengarry
Essex
Kent
Elgin
Brant
Hamilton-Wentworth
Halton
Metro Toronto
Northumberland
Leeds
Grenville
Dundas
Stormont
Haldimand-Norfolk
Niagara
Prince Edward
REGION 3
REGION 4

Attachment 1-SEC-8-A: October Budget Board Report

DATE: October 28, 2015 REPORT NO. BPI-1510-004

TO: Mr. Scott Saint, Chair and Directors

FROM: Brian D'Amboise, CFO & VP Corporate Services

1.0 TYPE OF REPORT:

☐ For Decision

☐ For Discussion

☒ For Information

2.0 TOPIC: 2016-2017 BUDGET AND MULTI-YEAR FORECAST UPDATE

3.0 RECOMMENDATIONS

Not Applicable

4.0 PURPOSE

To provide the Board of Directors an update on the preparation of the 2016-2017 Budget and Multi-Year forecast.

5.0 BACKGROUND

Management presents annually to the Board for approval, a proposed budget for the next fiscal year and financial forecasts for the subsequent four years. This year, Management is preparing a budget for both the 2016 and 2017 fiscal years and forecasts for 2018-2020. This is required as BPI must establish its expected cost of service to incorporate in the 2017 Cost of Service Rate Application scheduled to be filed with the Ontario Energy Board (OEB) in April 2016.

Although Management will be submitting budgets for both 2016 and 2017 fiscal years in December 2015, the approvals will represent approval of the 2016 Budget for next year as normal and a notional approval of the 2017 financial plan that will be incorporated into the 2017 Cost of Service rate application. Management will present for final approval in the fall of 2016, an updated 2017 Budget and Multi-Year forecast.

This updated budget is expected to be substantially in keeping with the 2017 financial plan approved this year as that was the basis of the rate application and resulting funding. However, it will be refreshed to reflect updated information available at that time.

In advance of submitting the final 2016-2017 Budget and Multi-Year Forecasts proposal to the Board for approval at the December 2015 Board meeting, Management has prepared this update report. This report will provide the Board with an advance look at the key 2016-2017 budget issues along with commentary on how Management expects to address these issues in the budget proposal. This will allow the Board the opportunity to provide input at this time which will assist Management in the compilation of the 2016-2017 budget proposals.

At this stage, Management has reviewed all of the departmental operating and capital budget submissions and related business plans and are currently incorporated them into the financial plan. The Senior Leadership Team (SLT) recently completed a detailed review of the major issues in play to finalize preliminary budget assumptions which are to be incorporated into the first draft of the Budget proposal.

The Finance Department will be compiling this first draft using these assumptions. SLT will review and refine the financial plan to ensure the 2016-2017 Budget and Multi-Year Forecasts reflects a prudent financial plan that balances the interest of the key stakeholders in a manner that will support a successful 2017 Cost of Service rate application.

Once the 2016-2017 Budget and Multi-Year Forecasts is approved by the Board in December, the Company is obligated to obtain the approval of its shareholder, Brantford Energy Corporation. It is anticipated this approval will also be obtained in December 2015.

6.0 INPUT FROM OTHER SOURCES

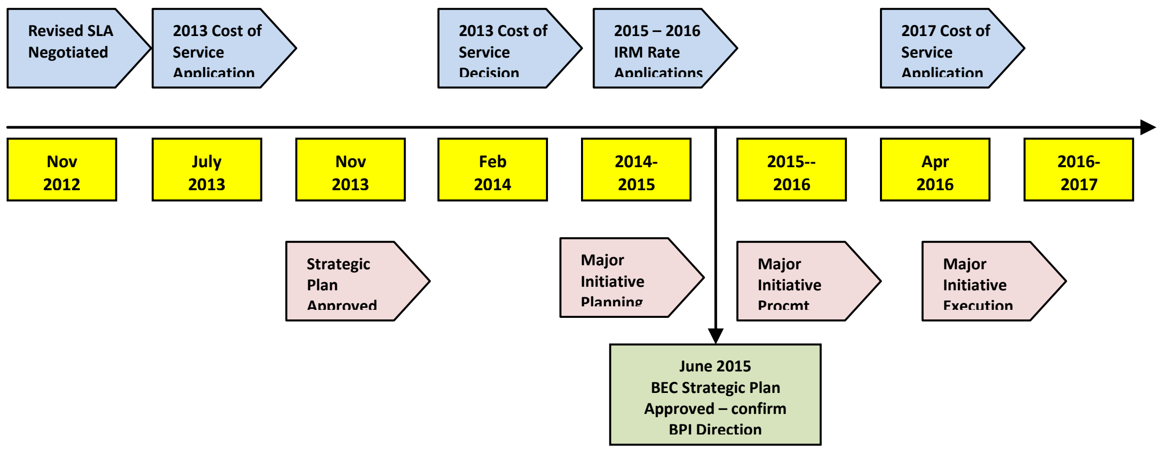
Not Applicable

7.0 STRATEGIC PLANNING CONTEXT

Before addressing the specific budgetary issues, it is important to review with the Board the current trajectory of the business vis a vis the approved strategic plan and how those initiatives align with the distribution rate funding calendar established through current OEB Cost of Service rebasing schedules.

The chronology below reflects side by side the milestones related to BPI's strategic plan development and implementation in comparison to the scheduled timing of major rate funding adjustments achieved through rate rebasing achieved during OEB Cost of Service rate applications which occur on a five year cycle. As Management prepares the 2016-2017 Budgets and Multi-Year Forecasts, these two chronologies converge in 2016-2017 to create some unique financial challenges in developing BPI's 2016 – 2017 Financial Plans.

Brantford Power Inc.
Chronology of Strategic Planning and Cost of Service Rate Rebasing



The Board will recall that the 2013 strategic plan approved five primary goals which set out a trajectory for the Company which fundamentally looked to accomplish growing and renewing the business. From a funding perspective, the 2013 Cost of Service rebasing was based on the previous BPI strategic plan priorities which was largely focused on a status quo operate and maintain agenda.

With a new strategic plan, the business' 2014 focus, in addition to core business functions and obligations, was largely to prepare plans and conduct research necessary to initiate the new strategic plan priorities. This was achieved by conducting research to develop work plans and approaches to achieve the strategic goals. For example BPI completed a Systems Integration Study, issued RFI's for FIS and CIS, completed a Meter to Cash review, initiated Customer Satisfaction and Customer Engagement initiatives, and participated with the IESO and neighboring utilities to develop an Integrated Regional Resource Plans (IRRP) etc. These varied activities were necessary to set the stage for BPI to implement action items necessary to move the business towards these strategic goals.

Although most of these activities were not funded in the 2013 Cost of Service decision, productivity gains achieved through organizational changes and acceptance by the Board of unfunded budgetary provisions for these strategic initiatives enabled these activities to proceed.

As BPI moved into 2015, the Business began to convert these plans into actual projects. Most notable of these were related to the preparation of RFP's for FIS and CIS, implementation of E services, conducting research on alternatives for a consolidated location and finalization of the IESO's IRRP. These activities identified the investments required to move these initiatives forward again in support of the primary strategic objectives. As was the case in 2014, these items were not funded in the distribution rates established in 2013 but BPI budget provisions were established to move these strategic initiatives forward.

For 2016 and 2017, the Company is moving to the execution phase of these major initiatives. Common to many of these initiatives are the following:

- New capital investments over and above the traditional distribution plant investments – in some case these reflect material costs e.g. new facilities, or transmission system upgrade capital contributions;
- Likely additional financing charges to finance these new investments;
- Need for back fill resources or other third party supports to implement these major initiatives e.g. FIS and CIS;
- Overlapping expenses as new costs related to new initiatives will begin before the existing costs can be eliminated – for example:
    - Duplicate building services costs while new facilities are prepared for transition while staff continue to occupy existing facilities;
    - Ongoing IT costs continue while new costs are incurred on new systems during implementation and testing.

The significance of these realities is that 2016 is the last year where distribution rate funding levels remain at the 2013 Cost of Service level adjusted in 2015 and 2016 with IRM inflationary adjustments. It will not be until 2017 that the funding levels will be rebased to reflect the impact of these BPI renewal and investment initiatives.

It is important to appreciate that the funding model established by the OEB is largely expecting a steady state approach where an LDC's new initiatives can be funded from productivity gains and new investments can be funded from reducing debt levels and savings from fully depreciated assets.

With the scope of business renewal underway including material investment plans e.g. new facilities, FIS, CIS etc. the BPI funding levels in play for 2016 which were established during the 2013 Cost of Service Rate Application will not be at the desired levels. Nevertheless, Management is working diligently to develop a 2016-2017 Budget and Multi-Year Forecast that accepts this reality, plans for proper funding adjustments in the 2017 rate rebasing process while being mindful of BPIs financial capacity to deliver the desired agenda and reflect the customers' ability to pay.

Although the preparation of a budget always involves trade-offs regarding priorities and timing, the convergence of BPI entering 2016 at the low point in the funding cycle while beginning to move into significant business transition will be presenting some financial challenges before addressing the normal budget issues outlined in this report.

Management believes it is important to provide the Board under the strategic planning context of this report a view on how the convergence of rate funding and strategic planning execution time lines create an overarching budget issue which will need to be addressed as BPI compiles its 2016-2017 Budget and Multi-Year forecast.

8.0 ANALYSIS

8.1 ANALYSIS – Introduction

As a result of the funding cycle outlined in the previous section and the pending rate rebasing in 2017, it is essential that BPI consider not only the immediate requirements but also consider the years immediately after rate rebasing. This is the case because the base revenue established in 2017 will be the base funding envelope for the subsequent four years. Although the 2017 budget is the basis for setting rates, there are some timing considerations driven by these regulatory realities that should be considered in creating the Company's multi-year financial plan. For example the timing of major capital expenditures could influence when the regulated return is fully adjusted for this investment.

The following graphic illustrates the key elements that must be addressed when preparing the 2016-2017 budgets:

Brantford Power Inc.
2016-2017 Budget and Multi-Year Forecast
Key Considerations

The focus of this budget report will be the key budget issues which will impact the development of BPI's 2016-2017 financial plan. In this regard, Management has reviewed these issues and established initial approaches to deal with them in the budget development.

As these issues are varied, one of the key challenges in the preparation of the 2016-2017 budgets is to understand and address the cumulative impacts of these matters in order to arrive at a prudent financial plan that accomplishes BPI's priorities in a manner that also achieves the objectives of the shareholder, the regulatory and customers.

As these implications become clear, it is prudent for BPI to consider how these will impact the regulatory strategy for the 2017 Cost of Service Rate Application.

8.2 ANALYSIS – Distribution Revenues

Prior to reviewing the specific issues being addressed in the 2016-2017 budgets, it is worthwhile to illustrate the rate funding issue raised in the strategic planning section. The current level of rate funding is based on the base level set during the 2013 Cost of Service Application. Because of the timing of the decision, BPI did not get an IRM adjustment in 2014 and received a modest adjustment in 2015.

The estimated top line revenue BPI will achieve should the 2016 IRM application be approved represents an increase of 1.8% or approximately $289,000. This is the amount that is available to fund regular inflationary costs plus any new costs BPI will require to implement its strategic agenda.

Clearly one of the primary challenges in this budget cycle will be to produce a prudent 2016 financial plan that delivers the planned agenda without substantive revenue growth and a 2017 Cost of Service application that balances the need to reflect new rebased costs within the capacity of customers to absorb.

8.3 ANALYSIS – Labour Costs

There are number of issues that impacts the future labour costs for BPI. Among the most significant are the following:

- Existing collective agreements expire in the near term:
  - 2016 - IBEW & Association
  - 2017 – CUPE
- The need to bring on temporary staffing as back fill to major implementation projects e.g. FIS or CIS;
- The need to evaluate and address BPI's competitive position for IBEW trade positions who at the expiry of their agreement will be the lowest paid tradespersons in the immediate geographic area and in some cases by a significant amount;

- The need to address succession planning on key operational roles both management and union;
- The growing cost of employee benefits and expected increases in CPP costs if the new government proceeds with enhancing this program;
- Possible organizational changes necessary should any existing SLA services be patriated to BPI when the SLA expires in 2017 (Addressed in a separate SLA section below)

The budget will need to address these cost realities as it develops the financial plan for 2016 and 2017 which will set the base for the subsequent four years.

8.4 ANALYSIS – Service Level Agreement (SLA)

The current SLA arrangements with the City of Brantford are scheduled to expire on January 1, 2017. As a result, the 2016 and 2017 Budgets will need to reflect any transitions resulting from potential changes to this arrangement. At the present time, the budget is assuming the following:

- Cost effective SLA services should be renewed in 2017;
- Given the change agenda underway with FIS, CIS, possible new facilities, other SLA services should be renewed for at least 2017 with possible option for subsequent years to allow for cost certainty and reliable evidence in the 2017 Cost of Service application and to ensure the capacity to implement the change agenda on other big projects is not compromised;
- 2016/2017 changes should be limited to those required to optimize the functioning of the new FIS.
- Depending on the timing of new facilities, changes in IT support and facilities maintenance may also be required.

To the extent any services will be transitions to BPI, some overlap costs will be required as new business processes are set up, tested and implemented and especially where new staffing is required.

8.5 ANALYSIS – System Integration Projects

The Board will recall that the original system integration report identified a number of projects that BPI should consider to achieve the necessary renewal to its IT infrastructure. As a result, the 2016-2017 Budget and Multi-Year forecast will reflect the anticipated costs for these initiatives as indicated below::

- Financial Information System (FIS) assuming it is operational by the end of 2016;
- Customer Information System (CIS) assuming it is operational by the end of 2017;
- A flat rate budgetary provision (capital and operating) will be provided in each year to fund the remaining yet to be scheduled projects.

Where firm costs are not yet known, Management will utilize the best information available to establish suitable budgetary provisions.

8.6 ANALYSIS – Consolidated Facilities

As this project is the largest material project BPI will encounter, the timing and costing is expected to have a significant impact on the business. As the timing of this project will have a significant impact on rates and shareholder returns, it is an ideal scenario that the Business is able to occupy the facilities in 2016. This will avoid being impacted by the half year rule, or require a more complex Advance Capital Module application in our rate application.

As a result, the budget is assuming the acquisition will take place in 2016 with occupancy no later than December 2016. The budget will utilize the current expected values for the transaction and will establish appropriate OM&A costs for the new facilities. This is another cost area where overlap costs can be expected given the existing facilities will continue to be occupied after the purchase of new facilities while they are being retrofitted for BPI requirements.

8.7 ANALYSIS – BGI Implications

With the ongoing challenges in BGI not yet resolved, the question of BGI shared service recoveries is an issue for BPI. Since it is not clear whether BGI will be a going concern and for how long, the budget will reflect ongoing support fees to BGI for shared executive and finance support. However, these charges will be offset with impairment allowances for budget purposes.

Since BPI may not recover service fees from BGI in the future, the 2017 Budget will assume BGI is no longer receiving services and this previously shared costs will become a cost of service to BPI.

Any existing and ongoing outstanding BGI affiliate charges will be offset by impairment allowances charged to non-utility accounts which do not impact customers. This is not theoretically a detriment to BPI as the 2013 Cost of Service rates were based on BPI not providing any services to any affiliates.

8.8 ANALYSIS – BEC Implications

The budget for BEC Management fees will reflect the impact of the restructured BEC Board of Directors and updated costs for shared executive and financial management costs. These will be higher beginning in 2016 as the BEC Budget will not reflect any recoveries from BGI thereby increasing the support costs to be absorbed by BPI and BHI. Since the OEB does not allow rate recovery of holding company charges, this change will have no impact on BPI customers.

A full review of all other BEC Group intercompany allocations will be updated and re-calibrated based on current causation drivers and the impairment of BGI recoveries.

BPI has sustained a $750,000 dividend for a number of years and the budget is expected to maintain this level. With the recent approval of the BEC strategic plan, it is expected that BEC will incur additional costs related to engagement of professional services to provide advice and due diligence on possible strategic transactions.

As was the case in 2015, BEC may also be asked to support financially other aspects of the BEC group activities. Provided the financial plan can sustain it, Management is considering increasing the dividend levels from the operating companies to BEC by modest amounts. This would allow BEC to retain some earnings for funding ongoing business development initiatives contemplated in the approved strategic plan without impacting the dividend expectations of the City of Brantford.

8.9 ANALYSIS – Customer Engagement

With the introduction of the OEB's Renewed Regulatory Framework focused on customer outcomes, LDC's have been required to focus on a number of non discretionary customer engagement activities including mandatory customer satisfaction surveys, need to demonstrate that rate applications and distribution system plans reflect customer preferences just to name a few. Costs related to customer engagement will be centralized and increased where necessary to reflect these activities which are now considered to be core activities for all LDCs.

8.10 ANALYSIS – Conservation

With the approval of the new Conservation plan, BPI has a clear view of the expectations to 2020. The budget will build into the load forecasts the achievement of required savings. Although not significant, any shared costs supporting CDM activities will be allocated to CDM business units and will not be included in the amounts to be recovered from distribution customers.

8.11 ANALYSIS – Capital Plan

The proposed capital plan will reflect prudent investments including the following:

- New consolidated facilities
- Capital contributions towards upgrades to the Transmission system in keeping with the Integrated Regional Resources Plan (IRRP) recommendations
- Priority projects identified from BPI's asset management program
- Expected investments for new customers
- Other investments necessary to respond to customer concerns raised during the various customer engagement initiatives.

It is expected that with the first two large one-time items, the total forecasted capital spending will be greater than those expended in recent years. Although increased investment is conducive to the "Grow the Utility" objective in the strategic plan, BPI will need to balance this objective with its own financial capacity and the capacity of customers to absorb resulting rate increases.

Management expects that some sequencing of the capital program will be necessary to ensure the capital program reflects the funding available and resulting customer impacts.

8.12 ANALYSIS – Financing

With the possible acquisition of a new building, possible capital contributions on transmission system upgrades, BPI will need to finance portions of its planned capital spending in 2016 and beyond. The objective in the financial plan will be to return BPI to the targeted 57% debt level.

One item of concern is the fact that Infrastructure Ontario (IO) has indicated that they are not prepared to lend additional funds to BPI until BGI circumstances have been resolved. Depending on the timing, BPI may need to obtain financing from traditional lenders. At issue is the fact that currently, Royal Bank, Infrastructure Ontario and the City of Brantford have sequential rights to BPI's assets pursuant to respective General Security Agreements.

As IO retains certain approval rights any new lender would have to be subordinated to 3rd or possible 4th level for access to assets under the GSA. Some lenders are prepared to enter into a pari passu arrangement where all lenders share the security on new loans on a pro rata basis. Other LDC's have indicated IO has not always been prepared to accommodate new lenders.

It will be important to determine what the source of financing will be as the 2017 Cost of Service Rate Application will need to reflect BPI's expected cost of capital. IO's current low rate with long amortization periods may not be available to BPI. With shorter amortization, results larger debt servicing costs as the principle needs to be repaid sooner. Depending on the terms, the availability of capital may be constrained.

Should IO prevent new borrowings, BPI could be in a position to need to replace IO as a lender. If IO agreed BPI would need to pay break fees estimated to exceed $300,000. Furthermore, the replacement of BPI's portfolio of very long term low interest rate instruments with shorter amortization more expensive commercial lending could significantly impact BPI's cost of capital that the OEB would need to approve for recovery in the distribution rates.

9.0 FINANCIAL IMPLICATIONS

The Finance Department has not yet fully completed the first draft of the 2016-2017 Budgets and Multi-Year forecasts. Once this is complete, SLT will review the outcomes in conjunction with the above noted issues to make any refinements that are required to produce a prudent and sustainable financial plan.

As the accumulation of financial impacts created by the above issues, it will be very important that BPI ensure that assumptions made are reasonable as the 2017 Budget will be the basis of the 2017 Test Year in the Cost of Service Application. This will set the top line beginning in 2017 and will be critical in determining what kind of returns BPI can achieve in the near term.

In the end, Management is committed to presenting in December a 2016-2017 Budget and Multi-Year forecast that reflects a prudent financial plan in keeping with the Company's strategic priorities while maintaining a strong financial position while remaining mindful of the Customer's ability to pay.

10.0 CONCLUSION

This report has provided the Board with an overview of the major budgetary issues and assumptions currently being addressed by the business. The goal is to complete the final 2016-2017 Budget and Multiyear forecast submission is complete and ready for consideration by the Board at the planned December meeting.

Submitted by,
Brian D'Amboise,
CFO & VP Corporate Services

ATTACHMENTS:

COPIES:

Attachment A –

Attachment 1-SEC-8-B: November Budget Report

DATE: December 16, 2015 **REPORT NO. BPI-1512-002**

TO: Mr. Scott Saint, Chair and Directors

FROM: Brian D'Amboise, CFO & VP Corporate Services

1.0 TYPE OF REPORT:

☐ **For Decision**

☐ **For Discussion**

☒ **For Information**

2.0 TOPIC: 2016-2017 BUDGET AND MULTI-YEAR FORECAST UPDATE

3.0 RECOMMENDATIONS

That the Brantford Power Inc. (BPI) Board of Directors approve the proposed 2016 Budget and Multi-Year forecast and recommend its approval to the Brantford Energy Corporation Board of Directors.

4.0 PURPOSE

To present to the Board of Directors for approval a proposed 2016 Budget and Multi-Year forecast with related background and explanatory information.

5.0 BACKGROUND

Management presents annually to the Board for approval, a proposed budget for the next fiscal year and financial forecasts for the subsequent four years. This year, Management is preparing a budget for both the 2016 and 2017 fiscal years and forecasts for 2018-2020. This is required as BPI must establish its expected cost of service to incorporate in the 2017 Cost of Service Rate Application scheduled to be filed with the Ontario Energy Board (OEB) in April 2016.

Although Management will be submitting budgets for both 2016 and 2017 fiscal years at this time, the approvals will represent approval of the 2016 Budget for next year as normal and a notional approval of the 2017 financial plan that will be incorporated into the 2017 Cost of Service rate application. Management will present for final approval in the fall of 2016, an updated 2017 Budget and Multi-Year forecast.

This updated budget is expected to be substantially in keeping with the 2017 financial plan approved this year as that will have been the basis of the rate application and resulting funding. However, it will be refreshed to reflect updated information available at that time.

Management provided a 2016-2017 budget update report at the October Board meeting. This current report will provide the Board with an update on the key 2016-2017 budget issues along with commentary on how Management has addressed these issues in the budget proposal. By submitting this budget proposal for approval, Management believes it reflects a prudent financial plan that balances the interest of the key stakeholders in a manner that will support a successful 2017 Cost of Service rate application.

Once the 2016-2017 Budget and Multi-Year Forecasts is approved by the BPI Board, the Company is obligated to obtain the approval of its shareholder, Brantford Energy Corporation (BEC). Provided the BPI Board approves the budget proposal on December 16, 2015, the approval from BEC will be requested later on December 16, 2015 when the BEC Board is convened.

Competing non-discretionary priorities, staff turnover and modeling difficulties significantly challenged the Finance Department to complete the proposed 2016-2017 Budget and Multi-Year Forecasts in time for issuance to the Board in advance of the scheduled Board meeting. As a result, the budget has literally been completed immediately before issuance to the Board. Although the budget has been reviewed for completeness and accuracy, sufficient time was not available to complete all of the customary quality assurance checks typically performed. Should material anomalies be identified prior to the Board meeting, updates will be provided.

6.0 INPUT FROM OTHER SOURCES

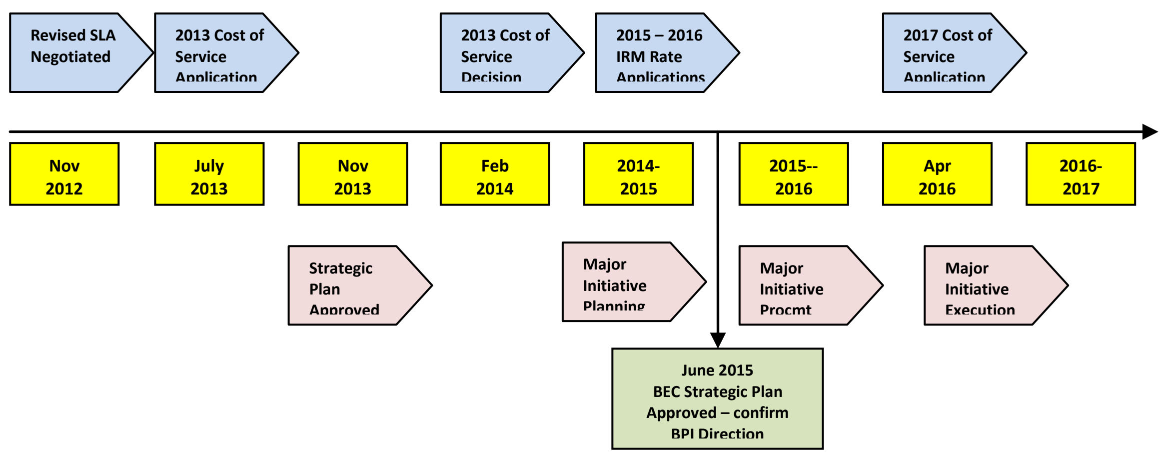
Not Applicable

7.0 STRATEGIC PLANNING CONTEXT

Before addressing the specific budgetary issues, it is important to review again with the Board the current trajectory of the business vis a vis the approved strategic plan and how those initiatives align with the distribution rate funding calendar established through current OEB Cost of Service rebasing schedules.

The chronology below reflects side by side the milestones related to BPI's strategic plan development and implementation in comparison to the scheduled timing of major rate funding adjustments achieved through rate rebasing achieved during OEB Cost of Service rate applications which occur on a five-year cycle. The proposed 2016-2017 Budget and Multi-Year Forecasts is prepared at a time where these two chronologies converge in 2016-2017. As reported in the October budget update, this timing has created some unique financial challenges in developing BPI's 2016 – 2017 Financial Plans.

Brantford Power Inc.
Chronology of Strategic Planning and Cost of Service Rate Rebasing



The Board will recall that the 2013 strategic plan approved five primary goals which set out a trajectory for the Company which fundamentally looked to accomplish growing and renewing the business. From a funding perspective, the 2013 Cost of Service rebasing was based on the previous BPI strategic plan priorities which was largely focused on a status quo operate and maintain agenda.

With a new strategic plan, the business' 2014 focus, in addition to core business functions and obligations, was largely to prepare plans and conduct research necessary to initiate the new strategic plan priorities. This was achieved by conducting research to develop work plans and approaches to achieve the strategic goals. For example, BPI completed a Systems Integration Study, issued RFI's for FIS and CIS, completed a Meter to Cash review, initiated Customer Satisfaction and Customer Engagement initiatives, and participated with the IESO and neighboring utilities to develop an Integrated Regional Resource Plans (IRRP) etc. These varied activities were necessary to set the stage for BPI to implement action items necessary to move the business towards these strategic goals.

Although most of these activities were not funded in the 2013 Cost of Service decision, productivity gains achieved through organizational changes and acceptance by the Board of unfunded budgetary provisions for these strategic initiatives enabled these activities to proceed.

As BPI moved into 2015, the Business began to convert these plans into actual projects. Most notable of these were related to the preparation of RFP's for FIS and CIS, implementation of E services, conducting research on alternatives for a consolidated location and finalization of the IESO's IRRP. These activities identified the investments required to move these initiatives forward again in support of the primary strategic objectives. As was the case in 2014, these items were not funded in the distribution rates established in 2013 but BPI budget provisions were established to move these strategic initiatives forward.

For 2016 and 2017, the Company is moving to the execution phase on some of these major initiatives. Common to many of these initiatives are the following:

- New capital investments over and above the traditional distribution plant investments – in some case these reflect material costs e.g. new facilities, or transmission system upgrade capital contributions;
- Additional financing charges to finance these new investments;
- Need for back fill resources or other third party supports to implement these major initiatives e.g. FIS and CIS;
- Overlapping expenses as new costs related to new initiatives will begin before the existing costs can be eliminated – for example:
    - Duplicate building services costs while new facilities are prepared for transition while staff continue to occupy existing facilities;
    - Existing IT costs continue while new costs are incurred on new systems during implementation and testing.

The significance of these realities is that 2016 is the last year where distribution rate funding levels remain at the 2013 Cost of Service level adjusted in 2015 and 2016 with IRM inflationary adjustments. It will not be until 2017 that the funding levels will be rebased to reflect the impact of these BPI renewal and investment initiatives.

It is important to appreciate that the funding model established by the OEB is largely expecting a steady state approach where an LDC's new initiatives can be funded from productivity gains. New investments can be funded from new debt room created by existing debt repayments and savings created as assets become fully depreciated.

With the scope of business renewal underway including material investment plans e.g. new facilities, FIS, CIS etc. the BPI funding levels in play for 2016 which were established during the 2013 Cost of Service Rate Application will not be at the desired levels. Nevertheless, Management has worked diligently to develop a 2016-2017 Budget and Multi-Year Forecast that accepts this reality, plans for proper funding adjustments in the 2017 rate rebasing process while being mindful of BPIs financial capacity to deliver the desired agenda and the customers' ability to pay.

In this regard, the proposed rebased distribution revenues in 2017 is projected to approximate the maximum 10% distribution rate increase allowed by the Ontario Energy Board without mandatory rate mitigation. At this level, BPI will not be able to recover 100% of its theoretical revenue requirement in 2017 leaving an estimated $1,000,000 in annual revenue requirement to the next rebasing period. This is not entirely unexpected given the materiality of the consolidated facilities.

It is also important to put the above 10% increase into context for the customer. A 10% increase in distribution charges is in fact a 2% impact on the total bill since the distribution portion represents only 20% of the total bill. Nevertheless, Management acknowledges the fact that customers have been burdened with numerous increases on their non-distribution elements of the bill in recent years and any new increases are likely not welcomed.

Management believes it is important to provide the Board under the strategic planning context of this report a view on how the convergence of rate funding and strategic planning execution time lines create an overarching budget issue which needed to be addressed in the preparation of the 2016-2017 Budget and Multi-Year forecast.

Although the preparation of a budget always involves trade-offs regarding priorities and timing, the convergence of BPI entering 2016 at the low point in the funding cycle while beginning to move into significant business transition costs and investments has presented BPI with financial challenges.

Management has attempted to keep the strategic plan agenda moving forward without jeopardizing the financial position of the business. This required balancing the following considerations:

- Short term financial performance;
- Regulatory risk with respect to the upcoming cost of service rate application;
- Impact on customers, and;
- Requirement to invest in the renewal of BPI.

8.0 ANALYSIS

8.1 ANALYSIS – Introduction

As a result of the funding cycle outlined in the previous section and the pending rate rebasing in 2017, it is essential that BPI consider not only the immediate requirements but also consider the years immediately after rate rebasing. This is the case because the base revenue established in 2017 will be the base funding envelope for the subsequent four years.

Although the 2017 budget is the basis for setting rates, there are some timing considerations driven by these regulatory realities that should be considered in creating the Company's multi-year financial plan. For example, the timing of major capital expenditures could influence when the regulated return is fully adjusted for this investment.

The following graphic illustrates the key elements that have been addressed in the proposed 2016-2017 budgets and multi-year forecasts:

Brantford Power Inc.
2016-2017 Budget and Multi-Year Forecast
Key Considerations

This budget report will highlight the key budget issues that impact the BPI's 2016-2017 financial plan and how they have been addressed. It will also provide a clear view of the expected financial outcomes that are being proposed.

As these issues are varied, one of the key challenges identified in the preparation of the 2016-2017 budgets is to understand and address the cumulative impacts of these matters. The resulting financial plan must provide for an outcome that accomplishes BPI's strategic priorities in a manner that also addresses the interests of the business, shareholder, regulator and customers. Management has also been mindful during the preparation of the budget to consider how these will impact the regulatory strategy for the 2017 Cost of Service Rate Application.

8.2 ANALYSIS – Distribution Revenues and load forecast

Prior to reviewing the specific issues being addressed in the 2016-2017 budgets, it is worthwhile to illustrate the rate funding issue raised in the strategic planning section. The current level of rate funding is based on the base level set during the 2013 Cost of Service Application. Because of the timing of the decision, BPI did not get an IRM adjustment in 2014 and received a modest adjustment in 2015.

The estimated top line revenue BPI will achieve based on the 2016 IRM rate order issued on December 10, 2015 represents an increase of 1.8% or approximately $289,000. This is the amount that is available to fund 2016 regular inflationary costs plus any new costs BPI will require to implement its strategic agenda.

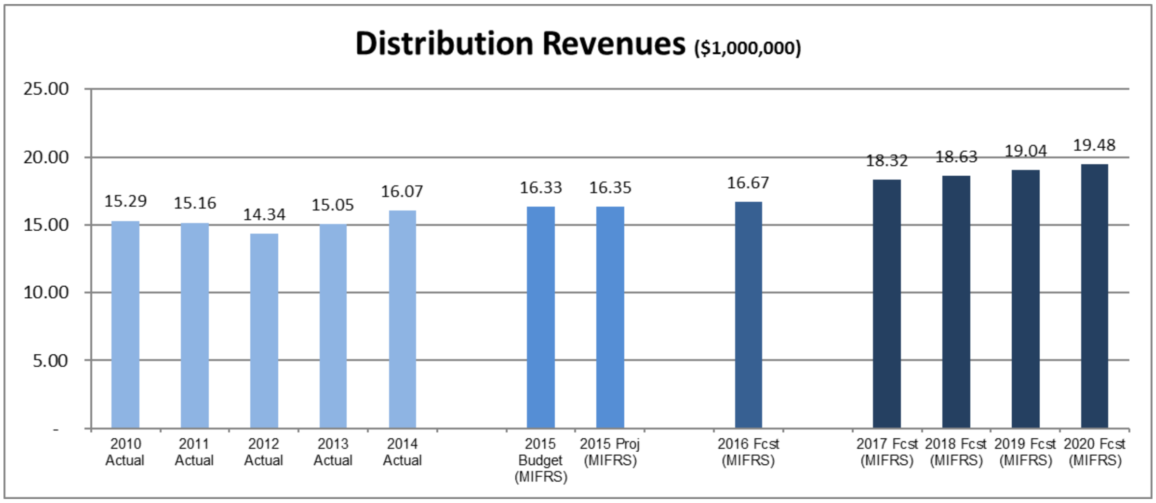
Clearly one of the primary challenges in developing the budget for 2016 was to produce a manageable 2016 financial plan that delivers the planned agenda without substantive revenue growth and a 2017 Cost of Service application that balances the need to reflect new rebased costs within the capacity of customers to absorb.

Details of the distribution revenue components have been reflected on Schedule F – Schedule of Commodity Recoveries and Other Revenues and Financial Expenses. In summary, the comparative distribution revenues can be summarized as follows:

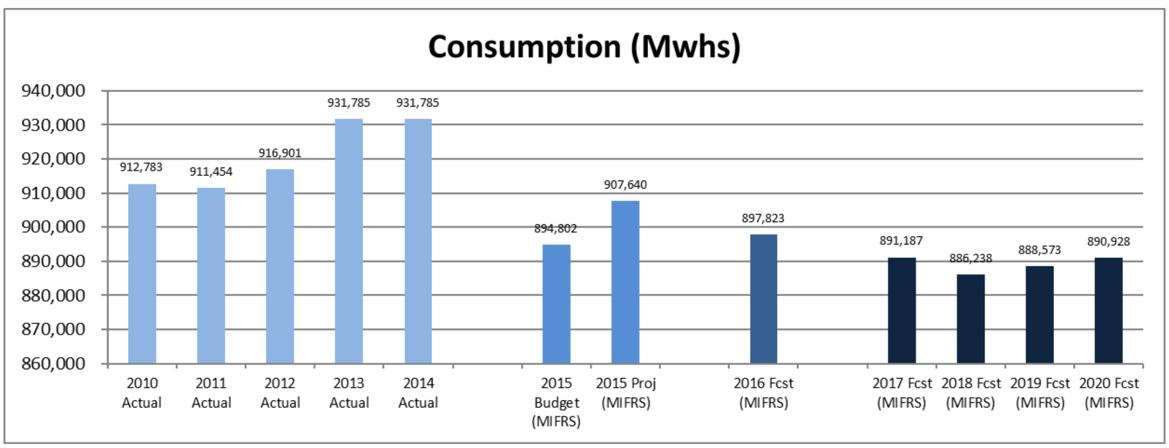
Brantford Power Inc.
2016- 2017 Budget & Multi-Year Forecast
Analysis of Distribution Revenues ($1,000)

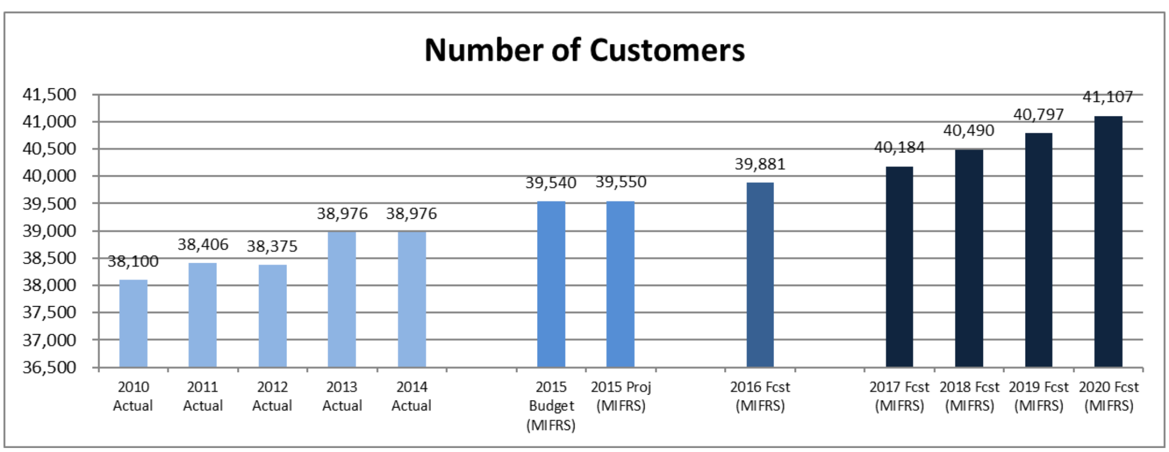
Component	2014 Actual	2015 Budget	2015 Projected	2016 Budget	2017 Budget
Base distribution Revenues	15,640	16,137	16,231	16,620	18,135
LRAM adjustments	116	207	133	61	201
Smart meter adjustments	310	(11)	(12)	(12)	(13)
Total	**$16,066**	**$16,333**	**$16,352**	**$16,669**	**$18,323**
% Change	**N/A**	**1.7%**	**1.8%**	**1.9%**	**9.92%**

Revenues beyond 2016 assume annual rate increases under IRM except for new Cost of Service rebased distribution rates in 2017.



The 2016 Budget and Multi-Year forecast assumes consumption levels, which are based on an internally developed load profiles taking into account a typical weather year and expected conservation impacts based on the new Conservation Framework targets. The results of this forecast are reflected in the following load and customer profiles:





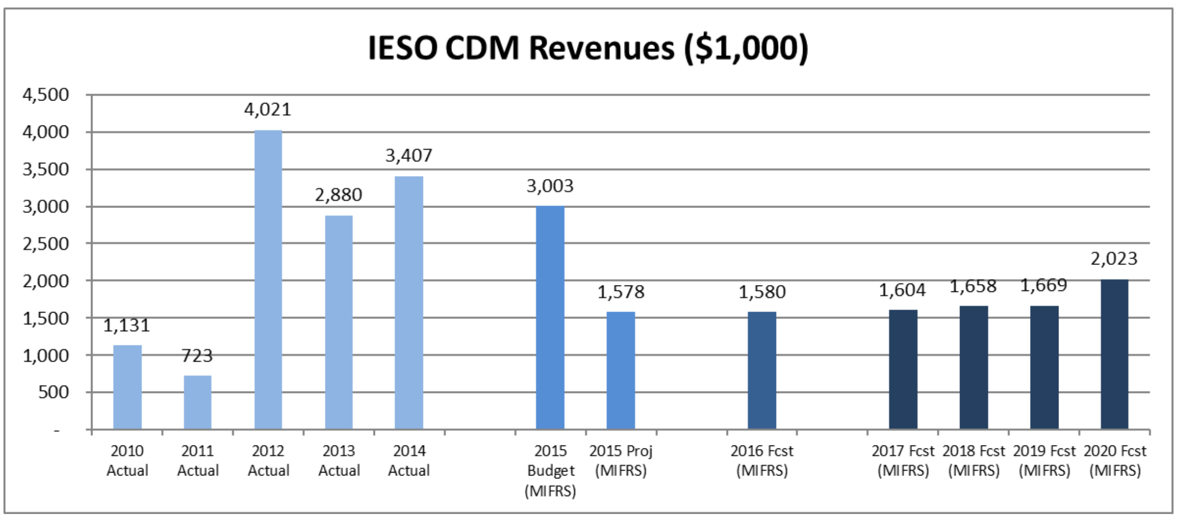
Refinements made to expected future consumption levels beyond 2016 indicates a stable consumption pattern in keeping with the objectives of the new Conservation Framework where limited growth is offset by conservation savings.

8.1 ANALYSIS – Conservation and Demand Management (CDM)

BPI recognized in 2015, $254,000 in Cost Efficiency Incentive on the Program Administration Budget under the previous 2011-2014 CDM Framework. As this is a one-time margin related to the 2011-2014 CDM Framework, the CDM program is forecasted to operate on a break even basis for the subsequent years.

BPI will be applying shortly to the OEB for a 2011-2014 CDM Framework performance incentive bonus since it met 168.6 % of its electricity savings (kWh) and 79.7% of its peak demand savings (kW) targets thereby meeting the eligibility threshold for these incentives. As this is subject to OEB review and award, Management has not reflected this additional performance incentive in the budget for 2016. Based on BPI calculations, the Company could be entitled to $293,520 which if approved would be recorded as an unbudgeted 2106 gain once approval has been confirmed. This is keeping with BPI's existing accounting policy for recognizing such incentives or bonuses.

The Board should note that the fluctuations in past OPA funding levels were largely influenced by the receipt and disbursement of the large cash flows provided for Ferraro's load displacement project.



8.3 ANALYSIS – OM&A Costs

The 2016 Budget provides for gross operating costs totaling $13,290,000 before allocations to the capital programs, CDM Programs or to affiliates for shared services. This represents a 12.5% or $1,475,000 increase over the 2015 gross operating costs of $11,814,000 reflected in the 2015 approved budget or a $1,966,000 or 17.4% over the 2015 Projections.

The 2016 Budget provides for net operating costs totaling $11,553,000 after allocations to the capital programs, CDM Programs or to affiliates for shared services. This represents a 13.1% or $1,346,000 increase over the 2015 budgeted net operating costs of $10,207,000 or a $1,923,000 or 20.0% increase over the 2015 Projections.

The increased in gross operating costs are attributable to a number of issues related to strategic investments and non-discretionary costs. Among these include the following:

- Increases in labor costs highlighted below including increased FTE's to address succession planning and strategic projects;
- An additional $220,000 in regulatory costs to cover the costs of the 2017 Cost of Service Application;
- A provision of $97,000 to cover the impairment of BGI service fees;
- An increase in the actuarially determined benefit expense for retirees of $70,000;
- An increase in overall facility costs of $198,000 largely the result of overlapping facilities during the last quarter of 2016 when new facilities are owned before BPI exits the existing facilities.

8.2 ANALYSIS – Labor Costs

There are number of issues that impacts the future labor costs for BPI which have been provided for in the proposed budget and multi-year forecast. Among the most significant are the following:

- Provisions to address renewed collective agreements which expire in the near term:
  - 2016 - IBEW & Association
  - 2017 – CUPE

  In this regard BPI has considered in this budget proposal BPI's competitive position for IBEW trade positions who at the expiry of their agreement will be the lowest paid tradespersons in the immediate geographic area and in some cases by a significant amount.
- Provisions for temporary staffing as back fill to major implementation projects e.g. FIS or CIS;
- Provisions to address succession planning on key operational roles both management and union in the technical areas of the business;
- The growing cost of employee benefits;
- Initial organizational changes necessary regarding SLA services to be patriated to BPI when the SLA expires in 2017 (Addressed in a separate SLA section below)
- The budget provides for some changes in the staffing complement to deal with new organizational requirements, succession planning or for project implementation as outlined below.

Brantford Power Inc.
2016-2017 Budget
Draft Proposed Staffing Complement

Department	2014 Actual	2015 Budget	2015 Projected	2016 Budget	2017 Budget
Senior Leadership Team	5.67	5.00	5.00	5.00	5.00
VP Operations & Engineering					
Engineering	8.00	8.00	8.67	9.00	9.00
Operations	17.24	17.00	17.67	18.50	19.00
VP Customer Service, CDM & Communications					
Settlement & Billing	5.00	5.00	3.33	5.00	5.00
Customer Service	13.74	14.58	15.33	12.92	13.92
CDM	2.00	2.00	1.63	3.00	3.00
Communications	0.70	1.00	0.69	0.69	0.69
CFO & VP Corporate Services					
Corporate Services	-	-	0.13	2.00	2.00
Regulatory	2.00	3.00	2.38	3.00	3.00
Finance	3.67	5.50	4.54	6.50	7.00
Total	**58.02**	**61.08**	**59.37**	**65.61**	**67.61**
Permanent FT	**54.29**	**55.00**	**54.00**	**57.25**	**59.00**
Permanent PT	**1.41**	**1.42**	**1.42**	**1.42**	**1.42**
Contract	**2.32**	**4.66**	**3.95**	**6.94**	**7.19**
Total	**58.02**	**61.08**	**59.37**	**65.61**	**67.61**

- The following reflect the highlights of the organizational changes contemplated in the budget:
  - Succession planning for anticipated retirements within the operations department including the provision of an additional supervisor in 2016;
  - Addition in 2016 of a Manager, System Projects and Business Applications to provide dedicated project management, training, system integration and training oversight as business processes migrate to new systems;
  - Addition in the CDM team to assist with the administrative elements of the programs;
  - The Finance Department and Customer Services Departments will continue to reflect additional temporary resources to backfill the planned FIS and CIS implementations.
- Although reflected in the Gross OM&A costs, there are recoveries for services provided to affiliates or for CDM activities which are funded from the IESO.

It is important to note in the graph below, that the increase in OM&A in 2013 from the levels in 2012 and prior was due to implementation of the OEB directive to adopt the IFRS approach to the capitalization of indirect overhead costs and to recognize the longer useful life of distribution assets. To put this change into perspective, BPI capitalized $843,000 of indirect overhead costs in its 2012 capital program.

The current trending on OM&A is as follows:

8.3 ANALYSIS – Service Level Agreement (SLA)

The current SLA arrangements with the City of Brantford are scheduled to expire on January 1, 2017. As a result, the 2016 and 2017 Budgets will need to reflect any transitions resulting from potential changes to this arrangement. At the present time, the budget is assuming the following:

- Cost effective SLA services should be renewed in 2017;
- Given the change agenda underway with FIS, CIS, possible new facilities, other SLA services should be renewed for at least 2017 with possible option for subsequent years to allow for cost certainty and reliable evidence in the 2017 Cost of Service application and to ensure the capacity to implement the change agenda on other big projects is not compromised;
- 2016/2017 changes have been limited to those required to optimize the functioning of the new FIS.

To the extent any services will be transitions to BPI, some overlap costs will be required as new business processes are set up, tested and implemented and especially where new staffing is required. With the plan of renewing services not impacted by FIS for 2017, the overlapping provisions have been limited.

8.4 ANALYSIS – System Integration Projects

The Board will recall that the original system integration report identified a number of projects that BPI should consider to achieve the necessary renewal to its IT infrastructure. As a result, the 2016-2017 Budget and Multi-Year forecast will reflect the anticipated costs for these initiatives as indicated below:

- Financial Information System (FIS) assuming it is operational by the end of 2016;
- Customer Information System (CIS) assuming it is operational by the end of 2017;
- Where detailed planning has not yet taken place regarding future System Integration initiatives, a flat rate budgetary provision (capital and operating) will be provided in each year to fund the remaining yet to be scheduled projects.

Where firm costs are not yet known, Management has utilized the best information available to establish suitable budgetary provisions.

Of the total $961,000 in special project costs provided for in the budget, a total of $709,000 is earmarked for System Integration Projects the largest being FIS in 2016 estimated at $588,000. As BPI has selected the hosted model for FIS, IFRS does not allow the capitalization of most elated implementation costs in these situations.

8.5 ANALYSIS – Consolidated Facilities

As this project is the largest material project BPI will encounter, the timing and costing is expected to have a significant impact on the business. As the timing of this project will have a significant impact on rates and shareholder returns, it is an ideal scenario that the Business is able to occupy the facilities in 2016. This will avoid being impacted by the half year rule, or require a more complex Advance Capital Module application in our rate application.

This initiative is the most pervasive item in the budget due to materiality and because operating costs is spread throughout the operating budget. Listed below are the key assumptions used to develop the budget regarding consolidated facilities. The assumptions are based on proceeding with the scenario that has been under consideration. Clearly the budget would be significantly impacted if this project did not proceed or if another site became available.

General:

- Acquire land & building with closing date of October 1, 2016.
- Assume all refurbishment costs can be capitalized, although a portion may need to be expensed.

Brantford Power Inc.
2016-2017 Budget and Multi-Year Forecast
Cost of Consolidated Facilities

Description	Amount
Acquisition cost	$10,800,000
Building refurbishments	4,475,000
Capitalized wages and expenses (Project Manager)	101,000
Total Cost	**$15,376,000**

In order to properly reflect the impact of the acquisition on the budget, the total cost must be componentized into specific asset groupings having specific useful lives to enable the proper calculation of depreciation amounts.

Brantford Power Inc.
2016-2017 Budget and Multi-Year Forecast
Total Costs Allocation to Asset Components

Description	Basis of Calculation	Amount
Building	What remains of acquisition cost + all other refurbishment costs	$7,770,000
Land	41 acres x $125,000/acre (as per estimated average land value per acre in Brantford)	5,125,000
HVAC	Based on estimate of Construction Costs/Site Improvements	1,451,000
Parking Lot	Estimate of acquisition price	500,000
Roofing	Estimate of acquisition price	300,000
Furnishings	Portion of acquisition price (60 people x $2,500/person)	150,000
Fencing	Based on estimate of Construction Costs/Site Improvements	80,000
Total Cost		**$15,376,000**

Building Occupancy (Total Space = 104,400 ft^2)
- Brantford Power - 37,000 ft^2 (based on Needs Assessment report)
- Brantford Hydro – 1,400 ft^2 (comparable to what is currently being occupied at BGI of 1,020 ft^2)
- Occupied by 3rd party – 10,000 ft^2 (based on current information)
- Excess space – 56,000 ft^2

Rental Income:
- Rental income of $19/ ft^2 (Based on rate used by COB for 84 Market rent of $12/ ft^2 + estimate of what is charged by COB for operational expenses through SLA of $7/ ft^2)
- Rental income commencing October 1/16 for tenants

Operating Costs:
- Estimate of $737,000 per year, increased by inflation of 2%. (Estimate determined by extrapolating 2015 actual facility operating costs that were provided for Jan –Aug 2015 (8 months).
- Costs are pro-rated in 2016 at 3/12 mths (consistent with acquisition date of Oct 1/16).
- SLA services (rent & operational expenses) ending Dec 31/16, with COB budget for 2016 used, totaling $574,902.

Loan Details:
- Principal Amount - $13,837,800 (90% of total capitalized building costs)
- Amortization Period – 30 yrs
- Interest Rate – 5%

Distribution Revenue Impact:

- Full value of building included in rate base despite larger than required on the basis that a green field build would have cost the same amount;
- Operating costs limited to proportion used by BPI;
- Total annual revenue requirement impact net of savings from current facilities $1,345,000 which translates to 5.02% increase in required distribution revenues;
- Unable to determine impact on various customer classes until rate design is completed following cost allocations of budget requirements to each customer class.

In addition to the OM&A elements, the impact of the new consolidated facilities will also result in an increase in annual financing charges approximating $230,000 and amortization of $300,000.

As this project is material, it will carry a degree of regulatory risk as the interveners will want to ensure customer contributions are limited to only those investments that were required for distribution purposes.

8.6 ANALYSIS – BGI Implications

With the ongoing challenges in BGI not yet resolved, the question of BGI shared service recoveries is an issue for BPI. Since it is not clear whether BGI will be a going concern and for how long, the budget will reflect ongoing support fees to BGI for shared executive and finance support. However, these charges will be offset with impairment allowances for budget purposes.

Since BPI may not recover service fees from BGI in the future, the 2017-2020 Budget and Forecasts although continuing to reflect impairments has the same effect as BGI no longer receiving services and these previously shared costs will become a cost of service to BPI.

Any existing and ongoing outstanding BGI affiliate charges will be offset by impairment allowances charged to non-utility accounts which do not impact customers. This is not theoretically a detriment to BPI as the 2013 Cost of Service rates were based on BPI not providing any services to any affiliates.

The projected 2016 BGI impairment allowance amounts to $97,000 (2015-$128,000).

8.7 ANALYSIS – BEC Implications

The budget for BEC Management fees reflects the impact of the restructured BEC Board of Directors and updated costs for shared executive and financial management costs. A full review of all other BEC Group intercompany allocations has been updated and re-calibrated based on current cost causation drivers.

8.8 ANALYSIS – Customer Engagement

With the introduction of the OEB's Renewed Regulatory Framework focused on customer outcomes, LDC's have been required to focus on a number of non discretionary customer engagement activities including mandatory customer satisfaction surveys, need to demonstrate that rate applications and distribution system plans reflect customer preferences and most recently the requirement to measure public electricity safety awareness. The budget has provided costs to meet these requirements.

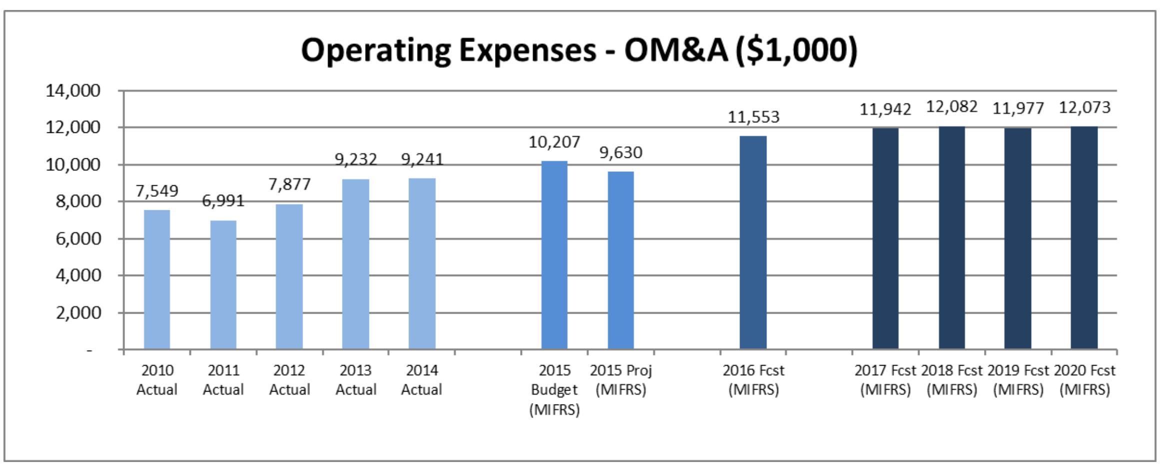
8.9 ANALYSIS – SPECIAL PROJECTS

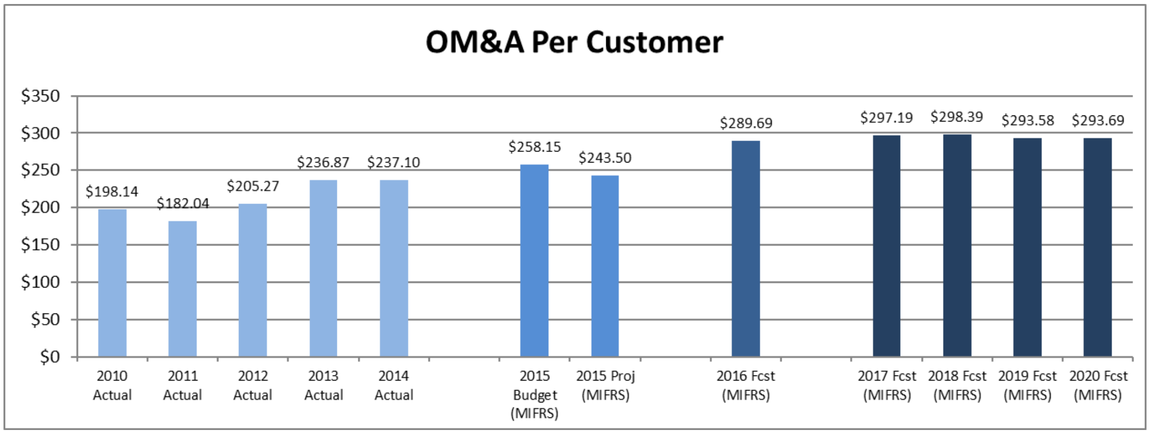
The financial plan provides a total funding of $961,000 for 2016 special projects. As previously outlined the most significant of these is the investments for FIS and other system integration initiatives totaling $709,000. The remaining 2016 funding of $252,000 provides funding for a number of initiatives including:

- Funding to obtain assistance to review and update BPI Policies;
- Funding to provide additional training;
- Funding to improve employee engagement
- Funding to refresh the current budget modelling that have been in use for a decade to address performance issues encountered in preparing this year's budgets and to reflect the impact of a new FIS with improved budget functionality.

8.10 ANALYSIS – OM&A Summary

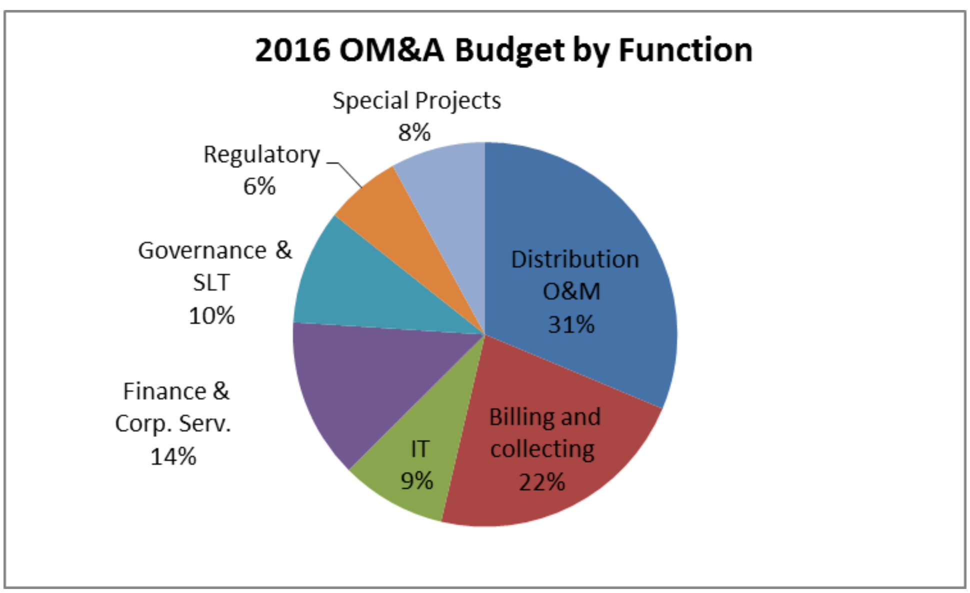
As previously outlined in the strategic considerations above, BPI is embarking on a number of strategic initiatives which impact the overall OM&A envelope in 2016 and the near term.





With the continued cost pressures created by new customer engagement obligations, increasing regulatory compliance costs, the higher costs for skilled labour due to the strong market competition for these scarce resources, limited capitalization opportunities under IFRS and other regular inflationary cost pressures combined with the inability of customers to absorb additional costs means BPI will need to find efficiencies in other areas.

The following pie chart indicates that BPI spends approximately $4.1 million or 31.0% of total OM&A on billing and collecting and IT which is an amount similar to the $4.2 million currently spent to operate and maintain the distribution system.



With the pending implementations of FIS and CIS over the next three years, BPI will have a real opportunity to review and modernize these business processes in order to provide efficiencies and related savings to redeploy funds to other priority functional areas.

8.11 ANALYSIS – Capital Plan

The proposed capital plan which will be supported by a Distribution System Plan that will be filed with the 2017 rate application will reflect prudent investments including the following:

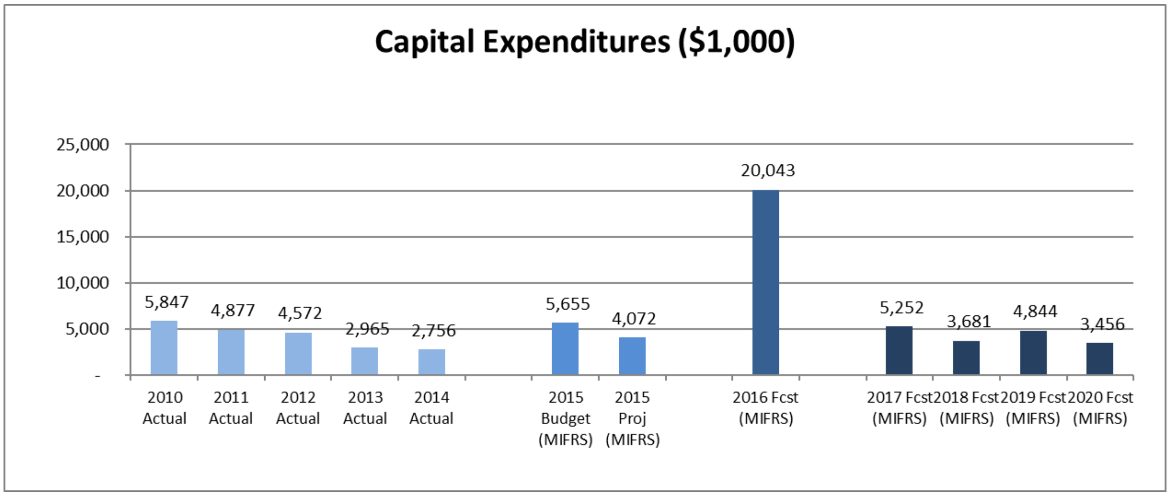
- New consolidated facilities;
- Capital contributions towards upgrades to the Transmission system in keeping with the Integrated Regional Resources Plan (IRRP) recommendations;
- Priority projects identified from BPI's asset management program;
- Expected investments for new customers;
- Other investments necessary to respond to customer concerns raised during the various customer engagement initiatives.

With the first two large one-time items, the total forecasted capital spending will be greater than those expended in recent years. Although increased investment is conducive to the "Grow the Utility" objective in the strategic plan, the budget proposal has attempted to balance this objective with its own financial capacity and the capacity of customers to absorb resulting rate increases.

Brantford Power Inc.
2016-2017 Budget and Multi-Year Forecast
Summary of Capital Expenditures ($1,000)

OEB Categories	2014 Actual	2015 Budget	2015 Proj.	2016 Budget	2017 Budget	2018 Fcst	2019 Fcst	2020 Fcst
System Access	$506	$584	$953	**$796**	**$925**	$958	$1,217	$1,111
System Services	1,113	1,731	$1,959	**2,745**	**3,227**	1,452	1,208	1,188
System Renewal	960	737	$629	**440**	**323**	588	1,907	822
General Plant	176	2,604	$531	**16,062**	**776**	593	512	335
Total	**$2,756**	**$5,655**	**$4,072**	**$20,043**	**$5,252**	**3,681**	**$4,844**	**$3,456**

Schedule E provides a summary of the specific projects that are earmarked in the 2016-2017 Budget and Multi-Year Forecast. The following graph illustrates the planned capital program.



8.12 ANALYSIS – Financing

With the acquisition of a new building, capital contributions on transmission system upgrades, BPI will need to finance portions of its planned capital spending in 2016 and beyond. The objective in the financial plan will be to return BPI to the targeted 57% debt level.

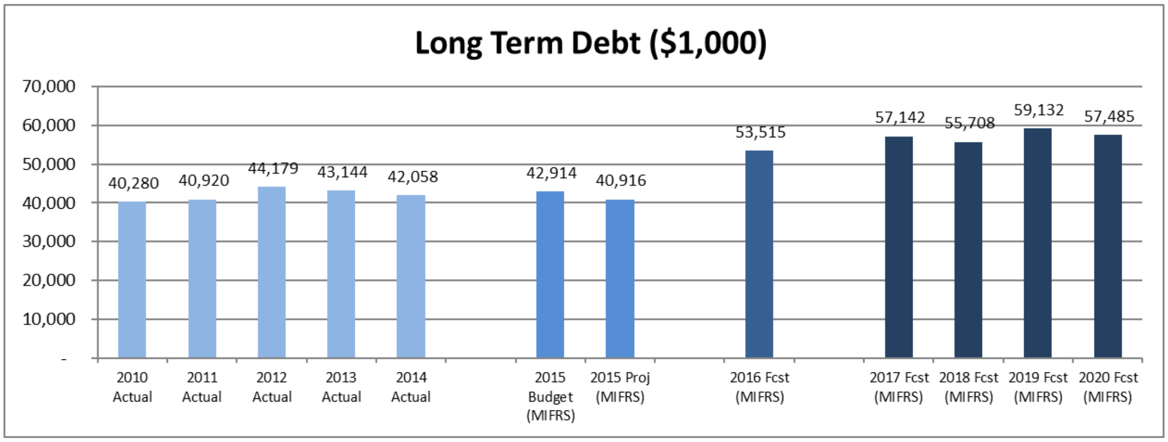
One item of concern is the fact that Infrastructure Ontario (IO) has indicated that they are not prepared to lend additional funds to BPI until BGI circumstances have been resolved. Depending on the timing, BPI may need to obtain financing from traditional lenders. At issue is the fact that currently, Royal Bank, Infrastructure Ontario and the City of Brantford have sequential rights to BPI's assets pursuant to respective General Security Agreements.

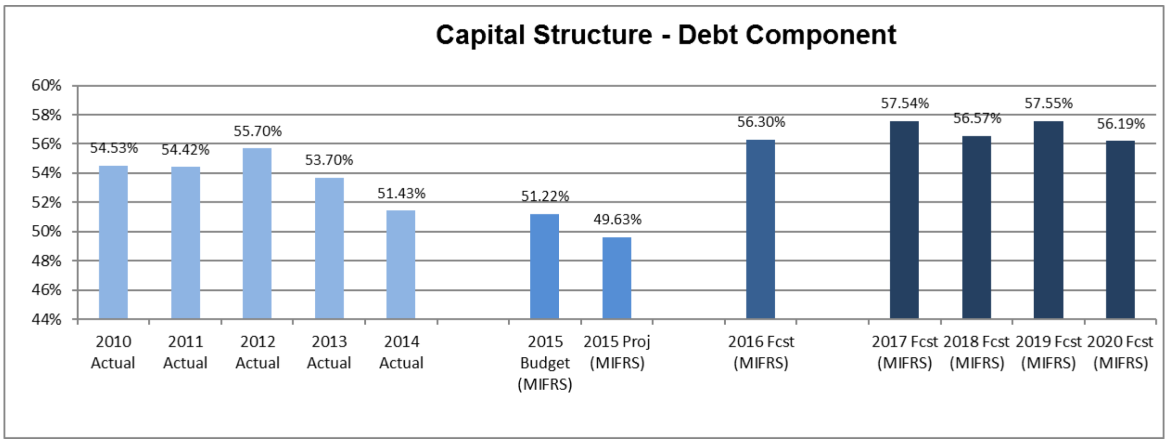
As IO retains certain approval rights any new lender would have to be subordinated to 3rd or possible 4th level for access to assets under the GSA. Some lenders are prepared to enter into a pari passu arrangement where all lenders share the security on new loans on a pro rata basis. Other LDC's have indicated IO has not always been prepared to accommodate new lenders.

As it is not certain that BPI could secure loans from OILC, the financing plan has assumed the rates available from commercial financial institutions.

The current budget has illustrated financing of 90% of the building in 2016 and a further $5,000,000 in general capital financing in 2017. In addition to providing the funds for these investments, this new financing will return BPI's capital structure to the target debt level approximating 57% which is in keeping with the maximum 60% debt level prescribed by the OEB.

As these projects develop, the actual timing of the financing could change to accommodate the timing of the capital expenditures for example – a delay in purchasing consolidated facilities.





The financing costs are based on the existing debt portfolio reflecting the current actual rates. The current City promissory note of $24,189,000 was last renewed on February 1, 2011 and will carry the rate of 5.87% until January 31, 2016. Thereafter, the budget has assumed the rate will drop to 4.20% reflecting the prime plus 1.5% stipulated for renewals and identified by the OEB process during the last Cost of Service decision as the level appropriate to charge customers for this debt.

The Board should note that the payment of promissory note interest is directly to the City of Brantford while the dividends are paid to the Brantford Energy Corporation, which will need to consider payment to the City. The revised interest rate will save BPI $404,000 per year keeping in mind that the OEB will recalibrate distribution rates to fund this reduced amount.

The timing of these borrowings will also allow BPI to get a significant proportion of its known debt service costs built into the cost of capital incorporated into the 2017 rebased distribution rates.

8.4 ANALYSIS – SHAREHOLDER PAYMENTS

BPI has sustained a $750,000 dividend for a number of years. The budget provides for additional dividends to BEC as outlined below. With the recent approval of the BEC strategic plan, it is expected that BEC will incur additional costs related to engagement of professional services to provide advice and due diligence on possible strategic transactions. More recently, BEC required funding to support an affiliated company.

Management has built into BPI's financial plan an increased dividend that BEC could retain without impacting the dividends it pays to the City of Brantford to support financially other aspects of the BEC group activities. This avoids the need to increase BEC Management fees which are not recoverable from customers in any event.

The Board recently declared a $250,000 dividend to BEC in response to a BEC request for capital funding. The request was for $500,000 with an immediate requirement for $250,000. BEC obtained the initial request. Management has included in the financial plan the payment of the second $250,000 tranche in 2016 should BEC make the request in 2016.

The financial plan is not detrimentally affected by these additional dividends. The provision of these dividends served to achieve the desired recapitalizing BPI's Balance Sheet to its targeted 43% equity level from the 50.3% equity level projected for the end of 2015. In addition, the financial plan has been prepared in a manner that provides the necessary funding to BEC to allow the continuation of BEC's pass through of the annual $750,000 BPI dividend to the City of Brantford in each year of the financial plan.

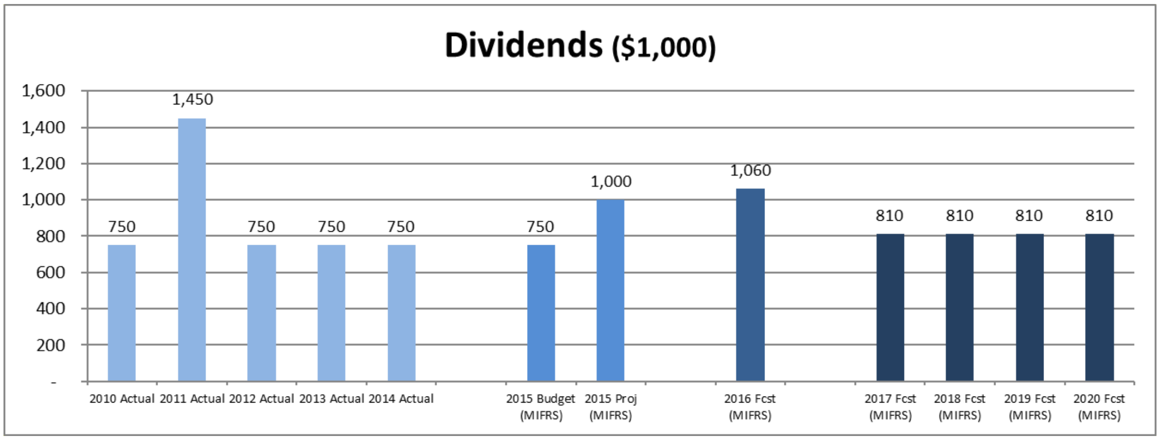
Based on the results in the 2016-2017 Budget and Multi-Year Forecast, the following payments are forecasted exclusive of any SLA payments for services rendered:

Brantford Power Inc.
2016-2017 Budget and Multi-Year Forecast
Summary of Dividends

Payments	2014 Actual	2015 Proj.	2016 Budget	2017 Budget
Based dividends	$750,000	$750,000	**$750,000**	**$750,000**
Regular enhanced dividends	-	-	**60,000**	**60,000**
One time dividends	-	250,000	**250,000**	**-**
Total Payments	**$750,000**	$1,000,000	**$1,060,00**	**$810,000**
Prior Year Reported Net Income	2,679,000	2,580,000	**2,589,000**	**1,044,000**
Total Dividend Payout % (Note 1)	30.0%	38.8%	**40.9%**	**77.6%**

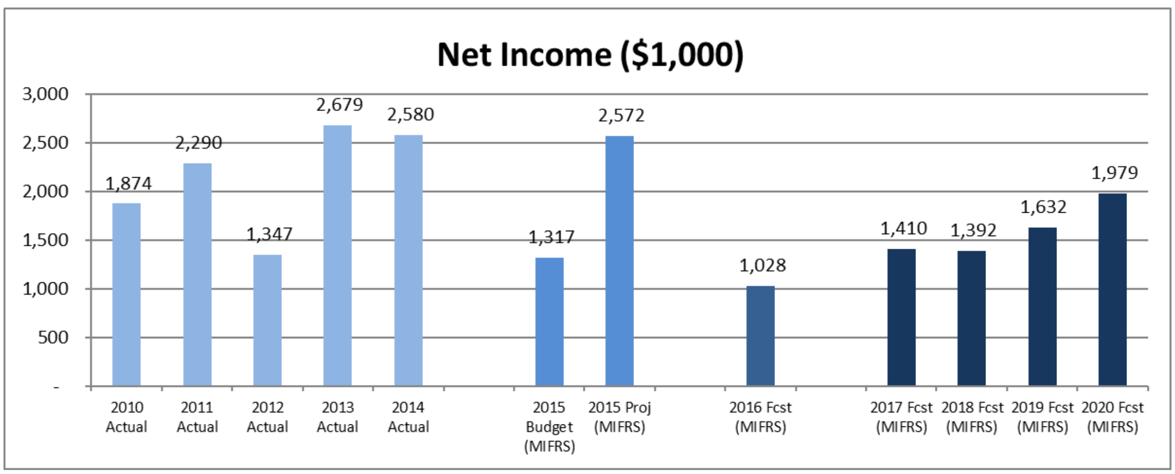
Note 1: *Dividend payout ratio is based on the current year payout divided over the prior year earnings. Many LDC's have specified dividend payout ratio from 50%-60%. Dividends at levels higher than these typical levels can be used to recalibrate the equity portion of the Company's Capital Structure.*

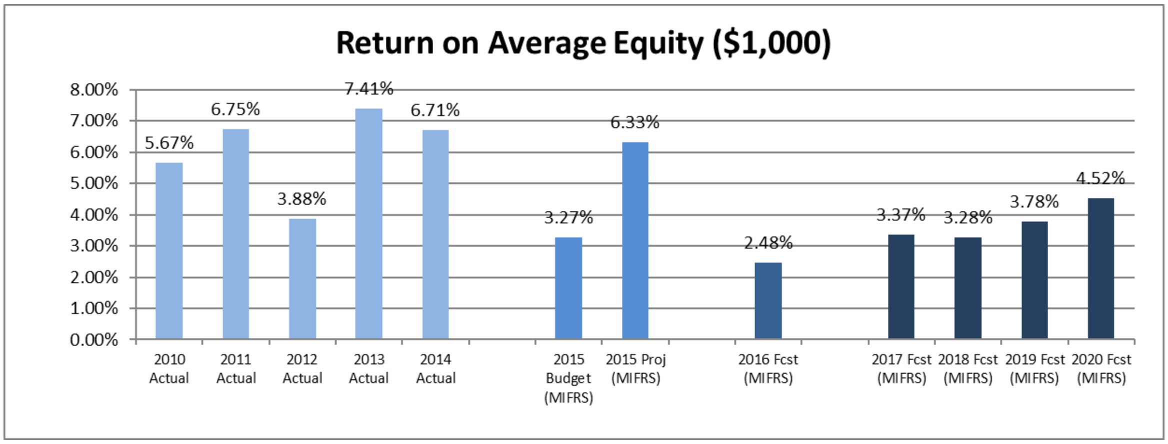
BPI's dividend record and forecast has been summarized below:



9.0 FINANCIAL IMPLICATIONS

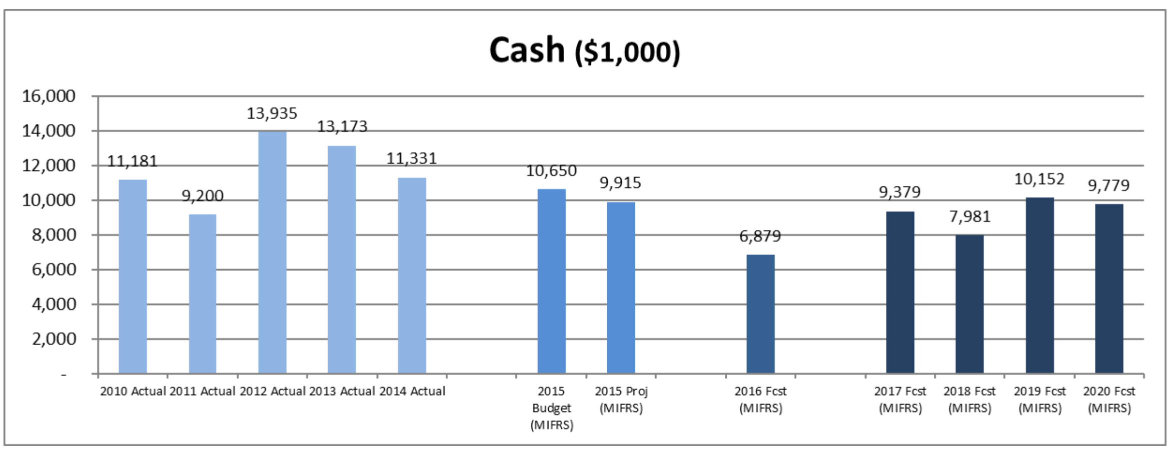
The 2016-2017 financial plan highlighted in this budget reflects significant investments contributing to the renewal of BPI. These new strategic investments combined with the higher transitional and one time costs in 2016 before rate rebasing has contributed to a lower targeted Net Income for 2016. Nevertheless, with the recent years of higher Net Incomes and the planned rebasing in 2017, this one modest year is not detrimentally impacting the longer term financial position of Brantford Power.



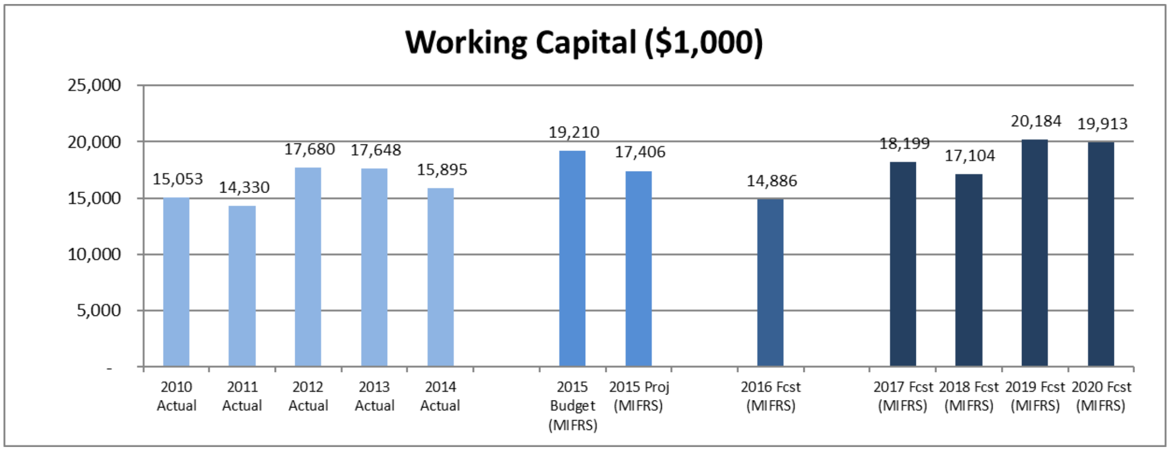


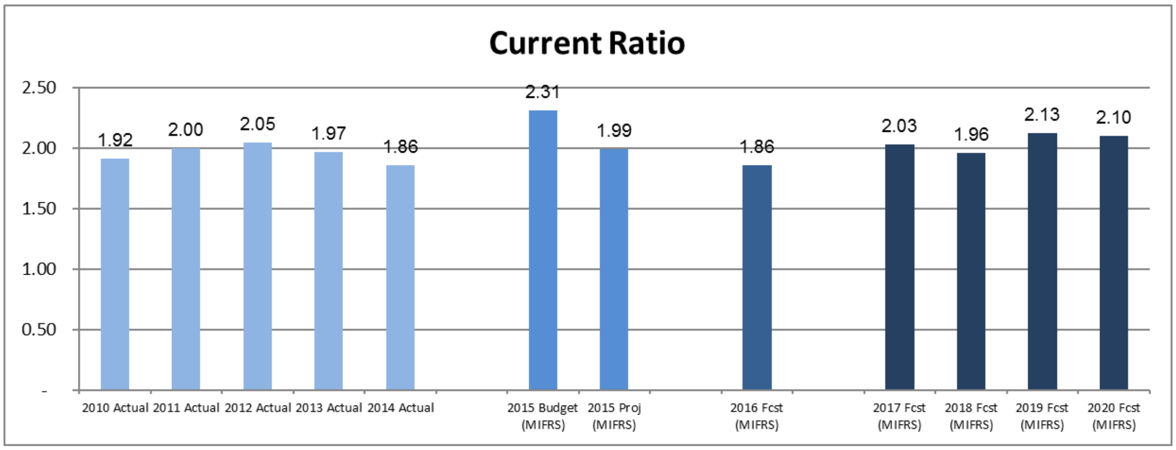
It is important to note that the lower than expected returns post rebasing in 2017 is largely due to the rate mitigation cap of 10% as BPI will be under collecting its theoretical revenue requirement until the subsequent next rebasing. In addition, the current financial plan reflects the fact that the ratepayers are not funding the BEC Management fees, BGI impairment provisions and the share of operating costs of the new building related to surplus space. This impact could be mitigated if BPI is able to find tenants for any excess space.

Based on the current 2016-2017 Budget and Multi-Year Forecast, BPI's financial position will remain solid despite the significant level of investment contemplated for 2016. With new financing, cash levels are expected to be lower than recent history but at levels providing sufficient liquidity.



The Company's' working capital levels reflect a relatively consistent level approximating a 2.0 current ratio throughout the 2016-2020 period.





In reviewing the Company's compliance with RBC and OILC debt covenants, the current forecast indicates that BPI is on side in every year. That year represents the year where BPI has an extraordinary level of capital expenditures with the largest capital costs for the new building.

In summary, Management believes the 2016-2017 Budget and Multi-Year Forecast reflects a base financial plan that focuses on short term investments required to implement the approved strategic plan with a goal of delivering longer term service and efficiency improvements. Such investments are necessary to enable sustainable and improving returns in the future.

10.0 CONCLUSION

Management believes the proposed 2016-2017 Budget and Multi-Year Forecast reflects a balanced financial plan which provides for a budgeted return that is below the level budgeted in 2015 largely due to the need for additional one-time costs required for BPI to pursue FIS and consolidated facilities.

Management has prepared a 2016-2017 Budget and Multi-Year forecast that reflects a prudent financial plan in keeping with the Company's strategic priorities. This plan maintains BPI's strong financial position while remaining mindful of the Customer's ability to pay.

10.0 CONCLUSION

This report has provided the Board with a complete briefing of the major budgetary issues and assumptions reflected in the proposed 2016-2017 Budget and Multiyear forecast. Management is recommending approval as it provides for a stable financial position while allowing for material investments necessary for the longer term effectiveness and sustainability of BPI.

Submitted by,
Brian D'Amboise,
CFO & VP Corporate Services

ATTACHMENTS:

COPIES:

Attachment A – 2016-2017 Budget and Multi-Year Forecast

Attachment 1-SEC-8-C: Final Budget

BRANTFORD POWER INC.

2016

BUDGET AND MULTIYEAR FORECAST

A

BRANTFORD POWER INC.
2016 BUDGET AND MULTI YEAR FORECAST
BALANCE SHEET

	JAN 1, 2014 Actual	2014 Actual	2015 Budget	2015 Projected	2016 Budget	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast
ASSETS									
CURRENT ASSETS									
Cash and cash equivalents	14,650,132	11,331,058	10,650,219	9,915,249	**6,879,228**	9,378,927	7,981,133	10,151,645	9,779,120
Accounts receivable	9,275,129	10,357,405	10,807,000	11,058,802	**11,260,912**	11,774,843	12,129,545	12,651,499	12,784,329
Due from affiliates	2,960	57,454	10,866	7,465	**5,882**	6,101	5,640	5,718	5,728
Unbilled revenue	11,018,050	10,642,144	11,073,186	12,312,081	**12,488,512**	13,015,807	13,372,755	13,912,254	14,049,605
Inventories	859,915	853,548	757,500	940,000	**949,400**	958,900	968,500	978,200	988,000
Prepaid expenses	142,849	205,612	146,500	180,000	**181,800**	183,600	185,400	187,300	189,200
Payments in lieu of taxes payable	324,099	622,158	167,551	342,743	**266,667**	295,974	66,197	-	-
Future payments in lieu of corporate income taxes	207,230	238,500	214,120	198,750	**198,750**	198,750	198,750	198,750	198,750
	36,480,363	34,307,880	33,826,942	34,955,090	**32,231,151**	35,812,902	34,907,920	38,085,366	37,994,732
CAPITAL ASSETS									
Distribution plant	63,415,700	66,147,367	72,048,296	69,736,339	**89,750,189**	94,965,242	98,381,758	103,261,466	106,901,677
Other equipment	1,446,016	1,670,874	2,235,939	2,314,001	**2,822,361**	3,338,121	4,081,661	4,524,501	4,819,661
	64,861,716	67,818,241	74,284,235	72,050,340	**92,572,550**	98,303,363	102,463,419	107,785,967	111,721,338
Accumulated amortization	-	3,153,561	6,013,997	6,327,559	**9,744,907**	13,457,085	17,344,433	21,393,425	25,434,253
	64,861,716	64,664,680	68,270,238	65,722,781	**82,827,643**	84,846,278	85,118,986	86,392,542	86,287,085
OTHER ASSETS									
Regulatory Assets	6,656,238	6,643,746	5,521,374	7,707,125	**6,554,299**	5,541,392	6,129,382	6,907,960	7,717,129
Long-term prepaid expenses	22,770	10,350	5,000	5,000	**5,000**	-	-	-	-
Future payments in lieu of corporate income taxes	170,857	-	-	-	**-**	-	-	-	-
	6,849,865	6,654,096	5,526,374	7,712,125	**6,559,299**	5,541,392	6,129,382	6,907,960	7,717,129
	$ 108,191,943	$ 105,626,656	$ 107,623,554	$ 108,389,996	**$ 121,618,093**	$ 126,200,572	$ 126,156,288	$ 131,385,868	$ 131,998,945

BRANTFORD POWER INC.
2016 BUDGET AND MULTI YEAR FORECAST
BALANCE SHEET

	JAN 1, 2014 Actual	2014 Actual	2015 Budget	2015 Projected	2016 Budget	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast
LIABILITIES									
CURRENT LIABILITIES									
Accounts payable and accrued liabilities	12,931,070	13,961,133	9,729,353	13,003,290	**12,972,190**	13,093,419	13,217,320	13,007,600	13,137,700
Accounts payable to the City of Brantford	952,468	639,065	505,000	500,000	**505,000**	510,100	515,200	520,400	525,600
Accounts payable to affiliates	283,273	132,803	253,323	180,000	**253,323**	299,434	300,265	301,020	301,804
OPA funds received in advance	769,197	353,759	800,000	510,248	**515,400**	520,600	525,800	531,100	536,400
Interest payable to the City of Brantford	1,419,904	1,419,904	1,419,904	1,419,904	**1,049,608**	1,015,945	1,015,945	1,015,945	1,015,945
Payments in lieu of taxes payable	-	-	-	-	**-**	-	-	161,060	135,387
Current portion of long-term debt	1,038,479	1,088,567	1,141,429	1,141,429	**1,240,153**	1,372,907	1,435,845	1,578,040	1,650,874
Current portion of customer deposits	790,223	818,050	767,750	794,500	**809,870**	801,770	793,740	785,790	777,920
	18,184,614	18,413,281	14,616,759	17,549,371	**17,345,544**	17,614,175	17,804,115	17,900,955	18,081,630
LONG TERM DEBT									
Promissory note payable	24,189,168	24,189,168	24,189,168	24,189,168	**24,189,168**	24,189,168	24,189,168	24,189,168	24,189,168
Long-term debt	18,954,417	17,868,536	18,724,422	16,727,106	**29,325,754**	32,952,847	31,518,863	34,942,779	33,295,820
	43,143,585	42,057,704	42,913,590	40,916,274	**53,514,922**	57,142,015	55,708,031	59,131,947	57,484,988
OTHER LONG TERM LIABILITIES									
Regulatory liabilities	6,479,604	2,663,315	5,126,292	4,335,903	**3,985,267**	2,601,653	2,224,268	2,260,137	2,295,487
Deferred revenue (capital contributions)	-	439,812	592,287	587,183	**1,045,695**	1,492,003	1,926,107	2,348,007	2,757,703
Long-term customer deposits	679,929	637,041	594,000	650,000	**643,500**	637,070	630,700	624,390	618,150
Employee future benefits	1,077,901	1,205,061	1,203,187	1,234,130	**1,299,939**	1,273,940	1,248,461	1,223,492	1,199,022
Accumulated sick leave credits	92,262	106,410	90,105	111,380	**96,409**	97,169	61,896	18,448	18,079
Future payments in lieu of corporate income taxes	-	57,715	1,267,000	1,122,055	**1,809,063**	2,837,981	3,439,671	3,917,287	4,387,142
Derivative liabilities	372,285	333,600	346,500	350,000	**346,500**	343,035	339,605	336,209	332,847
	8,701,982	5,442,954	9,219,371	8,390,651	**9,226,373**	9,282,851	9,870,708	10,727,970	11,608,430
	70,030,181	65,913,939	66,749,720	66,856,296	**80,086,839**	84,039,041	83,382,854	87,760,872	87,175,048
SHAREHOLDER'S EQUITY									
Share capital	22,437,505	22,437,505	22,437,505	22,437,505	**22,437,505**	22,437,505	22,437,505	22,437,505	22,437,505
Retained earnings	14,545,965	16,375,909	17,587,708	18,165,175	**18,132,729**	18,733,006	19,314,909	20,136,471	21,305,372
Contributed surplus	141,319	141,319	141,319	141,319	**141,319**	141,319	141,319	141,319	141,319
Accumulated Other Comprehensive Loss	1,036,974	757,984	707,302	789,701	**819,701**	849,701	879,701	909,701	939,701
	38,161,763	39,712,717	40,873,834	41,533,700	**41,531,254**	42,161,531	42,773,434	43,624,996	44,823,897
	$ 108,191,943	$ 105,626,656	$ 107,623,554	$ 108,389,996	**$ 121,618,093**	$ 126,200,572	$ 126,156,288	$ 131,385,868	$ 131,998,945

BRANTFORD POWER INC.
2016 BUDGET AND MULTI YEAR FORECAST
STATEMENT OF INCOME AND RETAINED EARNINGS

	2014 Actual	2015 Budget	2015 Projected	2016 Budget	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast
REVENUES								
Distribution revenues (Schedule F)	$ 16,065,685	$ 16,332,546	$ 16,352,204	**$ 16,668,859**	$ 18,322,060	$ 18,631,008	$ 19,043,246	$ 19,478,429
IESO CDM funding (formerly OPA)	3,407,271	3,002,925	1,577,700	**1,580,232**	1,604,367	1,658,163	1,668,795	2,022,585
Other Revenues (Schedule F)	1,180,729	1,004,684	1,150,455	**1,127,841**	1,280,881	1,307,379	1,385,799	1,461,249
	20,653,685	20,340,155	19,080,359	**19,376,932**	21,207,308	21,596,550	22,097,840	22,962,263
EXPENSES								
Operations, maintenance and administration	9,241,182	10,207,181	9,630,496	**11,553,091**	11,942,122	12,081,791	11,977,021	12,072,539
IESO CDM expenditures (formerly OPA)	3,407,271	3,002,925	1,324,183	**1,580,232**	1,604,367	1,658,163	1,668,795	2,022,585
Interest on promissory note - City of Brantford	1,419,904	1,419,904	1,419,904	**1,049,608**	1,015,945	1,015,945	1,015,945	1,015,945
Interest on other long term debt	876,894	858,580	813,010	**823,110**	1,551,720	1,592,120	1,672,460	1,613,350
Other Financial Expenses (Schedule F)	77,766	128,561	77,955	**79,514**	79,514	79,514	79,514	79,514
Amortization	3,017,303	2,929,428	2,994,562	**3,197,164**	3,463,779	3,602,008	3,715,627	3,696,081
	18,040,320	18,546,579	16,260,110	**18,282,719**	19,657,447	20,029,541	20,129,362	20,500,014
INCOME BEFORE TAXES	2,613,365	1,793,576	2,820,249	**1,094,213**	1,549,861	1,567,009	1,968,478	2,462,248
INCOME TAXES (PILS)								
Current income taxes	(148,808)	(167,551)	189,878	**(76,789)**	(295,974)	(66,197)	161,060	296,447
Future income taxes	182,228	643,951	58,651	**143,448**	435,558	241,302	175,856	186,900
	33,420	476,400	248,529	**66,659**	139,584	175,105	336,916	483,347
NET INCOME	$ 2,579,945	$ 1,317,176	$ 2,571,720	**$ 1,027,554**	$ 1,410,277	$ 1,391,904	$ 1,631,562	$ 1,978,901
Retained Earnings - Beginning of Year	$ 14,885,257	$ 17,020,532	16,593,455	**18,165,175**	$ 18,132,729	$ 18,733,005	$ 19,314,909	$ 20,136,471
Net Income	2,579,945	1,317,176	2,571,720	**1,027,554**	1,410,277	1,391,904	1,631,562	1,978,901
Adjustments - IFRS conversion								
Write off City SLA long lived prepaids	(78,471)	-	-	**-**	-	-	-	-
Write off AOCI resulting from interest rate swaps	(260,822)	-	-	**-**	-	-	-	-
	17,125,909	18,337,708	19,165,175	**19,192,729**	19,543,006	20,124,909	20,946,471	22,115,372
Dividends	(750,000)	(750,000)	(1,000,000)	**(1,060,000)**	(810,000)	(810,000)	(810,000)	(810,000)
RETAINED EARNINGS, End of Year	$ 16,375,909	$ 17,587,708	$ 18,165,175	**$ 18,132,729**	$ 18,733,006	$ 19,314,909	$ 20,136,471	$ 21,305,372

BRANTFORD POWER INC.
2016 BUDGET AND MULTI YEAR FORECAST
STATEMENT OF CASH FLOWS

	2015 Budget	2015 Projected	2016 Budget	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast
CASH FLOWS FROM OPERATING							
Net Income	$ 1,317,176	$ 2,571,720	**$ 1,027,554**	$ 1,410,277	$ 1,391,904	$ 1,631,562	$ 1,978,901
Adjustments for non cash items							
(Gain)Loss on disposal of property, plant and equi	(23,000)	(24,500)	**(15,000)**	5,000	5,000	5,000	5,000
Amortization	3,065,246	3,155,789	**3,396,860**	3,679,486	3,842,452	3,991,892	3,971,524
Changes in non cash working capital	(1,159,870)	(2,995,990)	**(630,003)**	(938,075)	(357,780)	(1,044,339)	(166,180)
Future payments in lieu of corporate income taxes	643,951	58,651	**143,448**	435,558	241,302	175,856	186,900
Other items not affecting cash	25,638	1,356,068	**620,898**	579,656	306,207	239,947	264,754
	3,869,141	4,121,738	**4,543,757**	5,171,902	5,429,085	4,999,918	6,240,899
CASH FLOWS FROM INVESTING							
Proceeds on disposal of property, plant and equipment	23,000	24,500	**15,000**	15,000	15,000	15,000	15,000
Capital expenditures	(6,005,275)	(4,232,100)	**(20,522,210)**	(5,730,813)	(4,160,056)	(5,322,548)	(3,935,371)
Changes in regulatory assets	934,613	609,209	**802,190**	(370,707)	(965,375)	(742,709)	(773,819)
	(5,047,662)	(3,598,391)	**(19,705,020)**	(6,086,520)	(5,110,431)	(6,050,257)	(4,694,190)
CASH FLOWS FROM FINANCING							
Increase in customer deposits	(13,750)	(10,591)	**8,870**	(14,530)	(14,400)	(14,260)	(14,110)
Repayment of outstanding long term debt	(1,088,567)	(1,088,569)	**(1,140,428)**	(1,240,153)	(1,371,046)	3,566,111	(1,574,125)
Increase in long term borrowings	2,000,000	-	**13,837,800**	5,000,000	-	-	-
Capital contributions received	350,000	160,004	**479,000**	479,000	479,000	479,000	479,000
Dividends	(750,000)	(1,000,000)	**(1,060,000)**	(810,000)	(810,000)	(810,000)	(810,000)
	497,683	(1,939,155)	**12,125,242**	3,414,317	(1,716,446)	3,220,851	(1,919,235)
INCREASE/(DECREASE) IN CASH	(680,838)	(1,415,809)	**(3,036,021)**	2,499,699	(1,397,792)	2,170,512	(372,526)
CASH AT BEGINNING OF YEAR	11,331,058	11,331,058	**9,915,249**	6,879,228	9,378,926	7,981,134	10,151,646
CASH AT END OF YEAR	$ 10,650,220	$ 9,915,249	**$ 6,879,228**	$ 9,378,926	$ 7,981,134	$ 10,151,646	$ 9,779,121

BRANTFORD POWER INC.
2016 BUDGET AND MULTI YEAR FORECAST
SCHEDULE OF CAPITAL EXPENDITURES

	2014 Actual	2015 Budget	2015 Projected	2016 Budget	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast
DISTRIBUTION PLANT - REGULAR OPERATIONS								
Transformer station equipment	$ 611,516	$ 625,000	$ 669,997	**$ -**	$ -	$ 49,971	$ 150,002	$ -
Overhead distribution system	890,306	1,036,007	1,366,093	**874,059**	883,086	807,763	570,557	693,662
Underground distribution system	387,569	1,037,017	957,107	**886,458**	1,261,379	1,468,528	2,869,781	1,793,516
Line transformers	317,357	332,618	216,928	**348,224**	382,615	420,465	462,126	507,552
Services	136,646	90,715	170,590	**283,196**	369,867	410,600	430,579	441,047
Meters	(74,821)	173,584	110,000	**89,626**	90,508	91,389	259,763	94,034
Capital contributions paid	168,856	-	-	**1,875,750**	1,876,798	-	-	-
Work in progress	(4,679)	-	-	**-**	-	-	-	-
	2,432,750	3,294,941	3,490,716	**4,357,313**	4,864,253	3,248,716	4,742,808	3,529,811
Land and land rights	4,250	1,500,000	8,475	**5,125,000**	-	-	-	-
Leasehold improvements	13,573	-	12,549	**-**	-	-	-	-
Buildings and fixtures	3,855	500,000	-	**10,250,349**	-	-	-	-
	2,454,428	5,294,941	3,511,740	**19,732,662**	4,864,253	3,248,716	4,742,808	3,529,811
GENERAL PLANT								
Computer software	118,625	98,294	50,687	**189,188**	315,000	150,000	100,000	100,000
Computer and office equipment	21,277	81,040	26,545	**92,000**	35,800	17,800	36,900	10,400
Vehicles	118,016	380,000	405,000	**400,000**	400,000	400,000	350,000	225,000
Tools, communication equipment and load control	26,373	85,000	58,000	**25,000**	25,000	25,000	25,000	-
System supervisory equipment (SCADA)	348,895	66,000	180,127	**83,360**	90,760	318,540	67,840	70,160
	633,187	710,334	720,360	**789,548**	866,560	911,340	579,740	405,560
Capital Budget - Gross	3,087,615	6,005,275	4,232,100	**20,522,210**	5,730,813	4,160,056	5,322,548	3,935,371
CAPITAL CONTRIBUTIONS	(331,936)	(350,000)	(160,004)	**(479,000)**	(479,000)	(479,000)	(479,000)	(479,000)
TOTAL CAPITAL EXPENDITURES	$ 2,755,680	$ 5,655,275	$ 4,072,096	**$20,043,210**	$ 5,251,813	$ 3,681,056	$4,843,548	$ 3,456,371

BRANTFORD POWER INC.
2016 BUDGET AND MULTI YEAR FORECAST
SCHEDULE OF CAPITAL EXPENDITURES BY PROJECT

	2014 Actual	2015 Budget	2015 Projected	2016 Budget	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast
New Lines and Equipment								
New services (roll-ins)	$ 76,695	$ 190,715	225,000	**339,676**	465,329	410,600	430,579	441,046
New overhead line extensions	135,280	182,320	150,000	**191,436**	196,849	198,364	200,595	224,041
New underground line extensions	233,217	263,428	460,000	**276,599**	289,399	492,599	384,599	276,599
New overhead transformers	14,009	31,114	55,000	**31,645**	34,888	38,465	42,407	46,712
New underground transformers	283,592	277,879	277,879	**291,776**	321,682	354,652	391,009	430,686
Powerline feeder upgrades	518,223	450,000	576,000	**-**	-	-	-	-
New subdivisions and townhomes costs	269,708	566,400	310,000	**295,706**	739,250	783,605	857,530	872,315
City/MTO overhead relocation - general	36,732	23,186	40,000	**24,345**	26,841	29,592	32,625	35,969
City/MTO overhead relocation - Shellard Lane	278,761	-	18,037	**6,480**	23,210	136,000	-	-
Dalhousie St. - new build and relocates	-	7,025	2,000	**100,000**	-	36,800	1,500,000	-
Scada and distribution automation	154,796	146,000	180,121	**259,318**	272,593	426,299	211,447	201,207
Capacitor study and installation of line banks	28,415	625,000	680,000	**-**	-	-	-	-
Powerline TS	-	18,750	18,750	**-**	-	-	-	-
	2,029,428	2,781,817	2,992,787	**1,816,981**	2,370,041	2,906,976	4,050,791	2,528,575
Conversion - Ownership								
Poles, towers and fixtures	-	5,250	-	**5,513**	5,788	6,078	6,381	6,700
Overhead conductors and devices	-	5,250	-	**55,513**	55,788	6,078	31,381	31,700
Underground conductors and devices	78,666	23,625	-	**24,806**	26,047	27,349	28,716	30,152
Line transformers	-	23,625	-	**24,806**	26,047	27,349	28,716	30,152
	78,666	57,750	-	**110,638**	113,670	66,854	95,194	98,704
Rebuild of Existing Lines and Equipment								
Poles, towers and fixtures	188,648	210,000	140,000	**207,250**	199,574	207,250	199,574	207,250
Overhead conductors and devices	9,734	40,000	75,811	**200,600**	186,243	112,000	8,000	50,000
Underground conduit	87,017	43,500	139,977	**106,388**	91,219	108,177	78,936	79,898
Underground conductors and devices	59,145	33,038	15,756	**26,480**	20,000	20,000	20,000	534,550
Line transformers	182,021	-	215,259	**-**	-	-	-	-
	526,565	326,538	586,803	**540,718**	497,036	447,427	306,510	871,698
Metering								
Metering (meters and instrument transformers	133,310	173,584	110,000	**89,626**	90,508	91,389	259,763	94,034
	133,310	173,584	110,000	**89,626**	90,508	91,389	259,763	94,034

BRANTFORD POWER INC.
2016 BUDGET AND MULTI YEAR FORECAST
SCHEDULE OF CAPITAL EXPENDITURES BY PROJECT

	2014 Actual	2015 Budget	2015 Projected	2016 Budget	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast
Other								
Land and land rights	4,250	1,500,000	8,475	**5,125,000**	-	-	-	-
Building and leasehold improvements	13,573	500,000	12,550	**10,250,349**	-	-	-	-
Upgrade AM/FM & GIS system: asset management	108,175	30,000	12,250	**45,800**	15,000	49,970	-	-
Financial Information System (FIS)	3,500	-	-	**48,500**	-	-	-	-
Customer Information System (CIS)	-	-	-	**-**	135,000	-	-	-
Systems installation (Other)	-	-	-	**-**	100,000	150,000	100,000	100,000
Departmental contingencies	21,508	202,046	-	**-**	-	-	-	-
Office furniture, computer hardware and software	25,132	28,540	76,232	**186,888**	100,800	17,800	36,900	10,400
Large bucket and other	118,015	380,000	405,000	**-**	400,000	-	-	-
Small bucket and other	-	-	-	**350,000**	-	400,000	250,000	175,000
Vans, cars and pickups	-	-	-	**50,000**	-	-	100,000	50,000
Tools, communication equipment and load control u	30,172	25,000	28,000	**31,960**	31,960	29,640	123,390	6,960
WIP	(4,679)	-	-	**-**	-	-	-	-
Capital contributions paid	-	-	-	**1,875,750**	1,876,798	-	-	-
	319,646	2,665,586	542,507	**17,964,247**	2,659,558	647,410	610,290	342,360
Capital Budget - Gross	3,087,615	6,005,275	4,232,097	**20,522,210**	5,730,813	4,160,056	5,322,548	3,935,371
Capital contributions	(331,936)	(350,000)	(160,000)	**(479,000)**	(479,000)	(479,000)	(479,000)	(479,000)
CAPITAL BUDGET - NET	2,755,680	5,655,275	4,072,096	**20,043,210**	5,251,813	3,681,056	4,843,548	3,456,371
Strategic	-	3,485,000	1,651,997	**18,061,179**	2,848,355	792,942	559,840	483,162
Confirmed	2,755,680	591,119	665,024	**230,416**	604,577	680,532	653,070	625,326
Tentative	-	1,377,112	1,733,825	**1,576,615**	1,678,881	2,138,864	3,499,388	2,272,883
Contingency	-	202,044	21,250	**175,000**	120,000	68,720	131,250	75,000
	2,755,680	5,655,275	4,072,096	**20,043,210**	5,251,813	3,681,058	4,843,548	3,456,371
System Access	506,365	583,511	952,879	**795,913**	925,060	957,922	1,217,142	1,111,346
System Services	1,112,944	1,730,890	1,959,184	**2,745,329**	3,227,360	1,542,109	1,207,996	1,187,927
System Renewal	960,431	736,538	628,776	**440,118**	323,593	588,227	1,906,510	821,698
General Plant	175,940	2,604,336	531,257	**16,061,850**	775,800	592,800	511,900	335,400
	2,755,680	5,655,275	4,072,096	**20,043,210**	5,251,813	3,681,058	4,843,548	3,456,371

BRANTFORD POWER INC.
2016 BUDGET AND MULTI-YEAR FORECAST
SCHEDULE OF COMMODITY RECOVERIES AND OTHER REVENUES AND FINANCIAL EXPENSES

	2014 Actual	2015 Budget	2015 Projected	2016 Budget	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast
COMMODITY RECOVERIES								
Energy	$ 82,501,935	$ 92,128,085	$ 91,671,981	**$ 92,499,091**	$ 96,268,013	$ 99,631,505	$ 104,569,583	$ 105,390,730
Transmission	11,063,711	12,219,403	12,353,951	**11,631,970**	11,455,934	11,419,652	11,464,288	11,502,560
Wholesale market service charges	5,242,003	5,271,377	5,113,538	**5,278,767**	5,258,352	5,229,376	5,243,259	5,257,305
Retail settlement variance adjustment	803,782	(324,216)	(992,956)	**243,182**	245,697	254,800	273,324	290,937
	99,611,430	109,294,649	108,146,514	**109,653,010**	113,227,996	116,535,333	121,550,454	122,441,532
COST OF POWER								
Energy	82,786,972	91,206,804	91,689,450	**92,875,891**	96,651,018	100,021,958	104,978,434	105,817,304
Transmission	11,814,494	13,765,316	12,355,192	**12,026,229**	11,844,461	11,806,937	11,853,087	11,892,653
Wholesale market service charges	5,009,965	4,322,529	4,101,872	**4,750,890**	4,732,517	4,706,438	4,718,933	4,731,575
	99,611,430	109,294,649	108,146,514	**109,653,010**	113,227,996	116,535,333	121,550,454	122,441,532
	-	-	-	**-**	-	-	-	-
DISTRIBUTION REVENUE								
Revenue	$ 15,639,889	$ 16,136,697	$ 16,231,337	**$ 16,619,655**	$ 18,134,699	$ 18,319,048	$ 18,684,976	$ 19,065,079
LRAM adjustments	115,596	207,073	132,650	**61,360**	200,610	311,960	358,270	413,350
Smart meter adjustments - rate application	310,199	(11,224)	(11,783)	**(12,156)**	(13,249)	-	-	-
	$ 16,065,685	$ 16,332,546	$ 16,352,204	**$ 16,668,859**	$ 18,322,060	$ 18,631,008	$ 19,043,246	$ 19,478,429
OTHER REVENUES								
Specific service charges	$ 539,109	$ 432,715	$ 552,825	**$ 496,272**	$ 506,195	$ 516,317	$ 526,642	$ 537,172
Late payment charges	207,146	175,000	222,971	**226,236**	235,599	242,076	251,796	254,171
Bank interest income	173,887	145,000	142,710	**149,337**	125,846	122,422	168,342	219,034
Other interest income	(497)	2,000	7,400	**7,000**	7,140	7,283	7,429	7,578
Interest (expense) on regulatory assets	31,019	46,225	37,621	**14,444**	2,387	8,175	14,068	18,654
Property rental	108,645	107,727	97,575	**153,677**	322,449	329,452	335,477	342,187
Retailer recoveries	62,739	59,517	58,863	**50,875**	50,965	51,048	51,127	51,217
Gain on derivative liabilities	35,847	3,500	-	**-**	-	-	-	-
Other revenue	22,833	33,000	30,490	**30,000**	30,300	30,606	30,918	31,236
	1,180,729	1,004,684	1,150,455	**1,127,841**	1,280,881	1,307,379	1,385,799	1,461,249
OTHER FINANCIAL EXPENSES								
IESO fees	$ 65,336	$ 66,476	$ 65,336	**$ 66,643**	$ 66,643	$ 66,643	$ 66,643	$ 66,643
Interest on customer deposits and retailer prud	12,430	12,718	12,619	**12,871**	12,871	12,871	12,871	12,871
Amortization of Other Comprehensive Income	-	49,367	-	**-**	-	-	-	-
	$ 77,766	$ 128,561	$ 77,955	**$ 79,514**	$ 79,514	$ 79,514	$ 79,514	$ 79,514

BRANTFORD POWER INC.
2016 BUDGET AND MULTI-YEAR FORECAST
SCHEDULE OF OPERATIONS, MAINTENANCE AND ADMINISTRATIVE EXPENSES NET OF ALLOCATIONS

	2014 Actual	2015 Budget	2015 Projected	2016 Budget	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast
DIRECT EXPENSES								
DISTRIBUTION OPERATIONS AND MAINTENANCE								
Distribution operations and maintenance	$ 2,043,593	$ 2,088,772	$ 1,697,955	**$ 2,067,331**	$ 2,093,871	$ 2,143,884	$ 2,209,773	$ 2,242,680
Engineering operations and maintenance	855,307	979,235	957,358	**1,057,009**	956,119	975,937	987,095	999,998
Settlement	873,845	926,137	1,027,611	**1,540,928**	1,538,688	1,568,677	1,595,050	1,614,772
Engineering Services	337,715	400,000	342,731	**357,428**	365,034	372,335	379,783	387,377
Transformer Station operations and maintenance	99,673	113,728	98,197	**104,595**	103,919	105,325	105,552	105,792
	4,210,133	4,507,872	4,123,853	**5,127,291**	5,057,631	5,166,158	5,277,253	5,350,619
BILLING AND COLLECTING	-							
Customer Services	1,857,141	1,856,150	1,964,385	**1,715,136**	1,693,007	1,697,406	1,737,357	1,763,758
LEAP Program	20,407	21,000	21,000	**21,000**	25,000	25,000	25,000	25,000
Bad debts	366,783	306,000	123,647	**300,000**	300,000	300,000	300,000	300,000
	2,244,330	2,183,150	2,109,032	**2,036,136**	2,018,007	2,022,406	2,062,357	2,088,758
DIRECT GENERAL AND ADMINISTRATIVE	-							
Board of Directors	58,235	79,650	43,526	**39,088**	39,215	39,392	39,572	39,755
Senior Leadership Team	829,730	735,046	981,275	**982,785**	961,009	965,112	995,250	1,002,785
Finance	530,463	461,847	549,375	**634,716**	651,027	562,312	573,467	586,473
Corporate Services and Regulatory Affairs	325,953	471,330	413,375	**613,340**	400,203	415,169	430,808	447,122
Corporate communications	60,398	73,281	62,336	**39,208**	42,213	44,215	46,313	48,513
Industry associations	62,400	60,000	60,000	**60,000**	60,600	61,206	61,818	62,436
Regulatory fees and costs	205,564	191,400	126,661	**269,641**	238,847	240,412	241,482	242,567
Bad debts- BGI Impairment	-	-	127,869	**96,810**	94,096	85,458	86,553	86,886
Corp - IT/Prj Mgr	-	-	17,321	**178,156**	291,829	303,895	316,824	330,355
	2,072,742	2,072,554	2,381,737	**2,913,745**	2,779,039	2,717,170	2,792,087	2,846,891
OTHER DIRECT COSTS	-							
Special projects	344,865	1,071,941	646,236	**961,167**	1,203,730	1,265,360	923,897	855,031
	344,865	1,071,941	646,236	**961,167**	1,203,730	1,265,360	923,897	855,031
	-							
TOTAL DIRECT EXPENSES	$ 8,872,070	$ 9,835,517	$ 9,260,857	**$ 11,038,339**	$ 11,058,407	$ 11,171,094	$ 11,055,594	$ 11,141,299

BRANTFORD POWER INC.
2016 BUDGET AND MULTI-YEAR FORECAST
SCHEDULE OF OPERATIONS, MAINTENANCE AND ADMINISTRATIVE EXPENSES NET OF ALLOCATIONS

	2014 Actual	2015 Budget	2015 Projected	2016 Budget	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast
INDIRECT GENERAL AND ADMINISTRATIVE EXPENSES								
OPERATIONS, MAINTENANCE AND ADMINISTRATION								
Retiree benefits	$ 44,506	$ 90,577	$ 83,765	**$ 160,916**	$ 160,701	$ 182,049	$ 180,777	$ 178,043
Records management, mail, telephone & duplicating	12,925	12,815	14,511	**13,828**	14,104	14,387	14,675	14,969
Insurance and risk management	97,926	104,602	86,000	**82,522**	84,172	85,855	87,572	89,323
Property charges	-	-	-	**118,939**	485,273	494,978	504,878	514,975
Legal	15,622	15,000	13,600	**12,190**	12,434	12,683	12,937	13,196
Brantford Energy Corp Management Fees	125,308	124,190	148,775	**103,357**	104,532	98,745	99,088	99,734
Other	72,825	24,480	22,988	**23,000**	22,500	22,000	21,500	21,000
TOTAL INDIRECT EXPENSES	$ 369,112	$ 371,664	$ 369,639	**$ 514,752**	$ 883,716	$ 910,697	$ 921,427	$ 931,240
	-							
TOTAL OPERATIONS, MAINTENANCE AND ADMINISTRATIVE EXPENSES	$ 9,241,182	$ 10,207,181	$ 9,630,496	**$ 11,553,091**	$ 11,942,122	$ 12,081,791	$ 11,977,021	$ 12,072,539
	-							
INDIRECT COSTS ALLOCATED	-							
To direct distribution operations and maintenance	$ 722,856	$ 954,805	$ 741,233	**$ 956,402**	$ 773,549	$ 806,342	$ 856,313	$ 870,663
To direct general and administration	307,523	329,385	336,501	**400,806**	256,444	261,577	266,805	272,141
To direct billing and collecting (customer service)	349,937	360,932	323,173	**400,818**	324,642	331,129	337,758	344,513
To OPA Conservation and Demand Management	24,752	24,300	24,835	**27,281**	19,211	19,595	19,987	20,387
	$ 1,405,069	$ 1,405,069	$ 1,425,742	**$ 1,785,307**	$ 1,373,846	$ 1,418,643	$ 1,480,863	$ 1,507,704
To recoverable	(448,991)	(370,148)	(364,351)	**(383,159)**	(409,282)	(412,336)	(419,094)	(424,601)
To capital	-	-	-	**-**	-	-	-	-
	$ (448,991)	$ (370,148)	$ (364,351)	**$ (383,159)**	$ (409,282)	$ (412,336)	$ (419,094)	$ (424,601)
NET INDIRECT COSTS ALLOCATED TO DIRECTS	$ 956,078	$ 1,034,921	$ 1,061,391	**$ 1,402,148**	$ 964,564	$ 1,006,307	$ 1,061,769	$ 1,083,103

BRANTFORD POWER INC.
2016 BUDGET AND MULTI-YEAR FORECAST
SCHEDULE OF DIRECT AND INDIRECT EXPENSES BEFORE ALLOCATIONS

	2014 Actual	2015 Budget	2015 Projected	2016 Budget	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast
DIRECT EXPENSES								
DISTRIBUTION OPERATIONS AND MAINTENANCE								
Distribution operations and maintenance	$ 2,830,357	$ 2,561,789	$ 2,598,010	**$ 2,905,810**	$ 3,083,538	$ 3,129,057	$ 3,185,791	$ 3,237,446
Engineering operations and maintenance	845,074	916,218	834,032	**829,068**	844,306	871,989	888,662	900,943
Settlement	801,783	844,298	878,196	**1,384,822**	1,411,453	1,439,197	1,463,039	1,480,196
Engineering Services	320,062	400,000	326,300	**337,587**	344,339	351,226	358,251	365,416
Transformer Station operations and maintenance	99,673	113,728	98,197	**104,595**	103,919	105,325	105,552	105,792
	4,896,950	4,836,033	4,734,735	**5,561,882**	5,787,555	5,896,794	6,001,295	6,089,793
BILLING AND COLLECTING								
Customer Services	1,475,967	1,524,224	1,611,070	**1,261,656**	1,328,795	1,325,215	1,356,506	1,375,370
LEAP Program	20,407	21,000	21,000	**21,000**	25,000	25,000	25,000	25,000
Bad debts	366,783	306,000	123,647	**300,000**	300,000	300,000	300,000	300,000
	1,863,156	1,851,224	1,755,717	**1,582,656**	1,653,795	1,650,215	1,681,506	1,700,370
DIRECT GENERAL AND ADMINISTRATIVE								
Board of Directors	40,404	54,250	34,559	**34,559**	34,645	34,731	34,818	34,906
Senior Leadership Team	865,096	891,582	1,121,484	**1,082,604**	1,119,192	1,113,220	1,144,035	1,152,295
Finance	421,482	419,352	429,652	**478,505**	558,235	461,801	470,781	481,577
Corporate Services and Regulatory Affairs	227,403	323,717	306,247	**534,909**	334,447	348,098	362,396	377,342
Corporate communications	60,398	73,281	62,336	**39,208**	42,213	44,215	46,313	48,513
Industry associations	62,400	60,000	60,000	**60,000**	60,600	61,206	61,818	62,436
Regulatory fees and costs	205,564	191,400	126,661	**269,641**	238,847	240,412	241,482	242,567
Bad debts- BGI Impairment	-	-	127,869	**96,810**	94,096	85,458	86,553	86,886
Corp - IT/Prj Mgr	-	-	17,321	**278,870**	291,829	303,895	316,824	330,355
	1,882,747	2,013,582	2,286,128	**2,875,107**	2,774,104	2,693,036	2,765,020	2,816,877
OTHER DIRECT COSTS								
Special projects	344,865	1,071,941	646,236	**961,167**	1,203,730	1,265,360	923,897	855,031
	344,865	1,071,941	646,236	**961,167**	1,203,730	1,265,360	923,897	855,031
TOTAL DIRECT EXPENSES	$ 8,987,717	$ 9,772,780	$ 9,422,816	**$ 10,980,812**	$ 11,419,184	$ 11,505,405	$ 11,371,718	$ 11,462,071

BRANTFORD POWER INC.
2016 BUDGET AND MULTI-YEAR FORECAST
SCHEDULE OF DIRECT AND INDIRECT EXPENSES BEFORE ALLOCATIONS

	2014 Actual	2015 Budget	2015 Projected	2016 Budget	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast
INDIRECT EXPENSES								
INDIRECT GENERAL AND ADMINISTRATIVE EXPENSES								
Retiree benefits	$ 44,506	$ 90,577	$ 83,765	**$ 160,916**	$ 160,701	$ 182,049	$ 180,777	$ 178,043
Records management, mail, telephone & duplicating	20,969	21,395	21,800	**22,408**	22,856	23,314	23,781	24,257
Insurance and risk management	108,391	115,822	86,000	**82,522**	84,172	85,855	87,572	89,323
Treasury and accounting	72,849	70,686	79,200	**87,039**	-	-	-	-
Purchasing and dispatch	102,625	90,939	179,814	**180,455**	183,380	185,041	188,372	191,619
Management information systems	741,961	862,816	747,100	**898,448**	916,417	934,745	953,440	972,509
Property charges	498,536	498,061	510,200	**696,063**	751,669	766,702	782,036	797,677
Legal	15,622	15,000	13,600	**12,190**	12,434	12,683	12,937	13,196
Human resources	114,533	99,738	69,500	**66,905**	68,243	69,608	71,000	72,420
Minor capital improvements	-	30,000	-	**-**	-	-	-	-
Brantford Energy Corp Management Fees	125,308	124,190	148,775	**103,357**	104,532	98,745	99,088	99,734
Other	72,825	24,480	22,988	**23,000**	22,500	22,000	21,500	21,000
Fleet recovery	(139,433)	(2,618)	(61,728)	**(24,567)**	(46,217)	(27,814)	5,846	3,707
	1,778,693	2,041,086	1,901,014	**2,308,736**	2,280,687	2,352,928	2,426,349	2,463,485
GRAND TOTAL OPERATIONS, MAINTENANCE AND ADMINISTRATIVE EXPENSES	$ 10,766,410	$ 11,813,866	$ 11,323,830	**$ 13,289,548**	$ 13,699,871	$ 13,858,333	$ 13,798,067	$ 13,925,556

BRANTFORD POWER INC.
2016 BUDGET AND MULTI-YEAR FORECAST
SCHEDULE OF DIRECT AND INDIRECT EXPENSES - DETAIL

	2015 Budget	2015 Projected	2016 Budget	Direct Salaries, Wages & Benefits	Direct Goods & Services	City SLA	Total Gross Direct & Indirect Costs	Allocation of Indirect Costs to Operational Accounts	Fully Allocated Direct & Indirect Costs	Allocation to CDM, Affiliate, Capital or Billable Projects	Net Direct and Indirect Costs
DISTRIBUTION OPERATIONS AND MAINTENANCE											
Distribution operations and maintenance	$ 2,088,772	$ 1,697,955	**$ 2,067,331**	1,818,284	1,087,526	-	**$ 2,905,810**	301,566	**$ 3,207,376**	(1,140,045)	**$ 2,067,331**
Engineering operations and maintenance	979,235	957,358	**1,057,009**	609,514	219,554	-	**829,068**	461,724	**1,290,792**	(233,783)	**1,057,009**
Settlement	926,137	1,027,611	**1,540,928**	582,110	802,712	-	**1,384,822**	157,343	**1,542,165**	(1,237)	**1,540,928**
Engineering Services	400,000	342,731	**357,428**	-	-	337,587	**337,587**	19,841	**357,428**	-	**357,428**
Transformer Station operations and maintenance	113,728	98,197	**104,595**	6,470	90,825	7,300	**104,595**	-	**104,595**	-	**104,595**
	4,507,872	4,123,853	**5,127,291**	3,016,378	2,200,617	344,887	**5,561,882**	940,474	**6,502,356**	(1,375,065)	**5,127,291**
BILLING AND COLLECTING											
Customer Services	1,856,150	1,964,385	**1,715,136**	948,733	312,923	-	**1,261,656**	453,480	**1,715,136**	-	**1,715,136**
LEAP Program	21,000	21,000	**21,000**	-	21,000	-	**21,000**	-	**21,000**	-	**21,000**
Bad debts	306,000	123,647	**300,000**	-	300,000	-	**300,000**	-	**300,000**	-	**300,000**
	2,183,150	2,109,032	**2,036,136**	948,733	633,923	-	**1,582,656**	453,480	**2,036,136**	-	**2,036,136**
DIRECT GENERAL AND ADMINISTRATIVE											
Board of Directors	79,650	43,526	**39,088**	15,959	18,600	-	**34,559**	4,529	**39,088**	-	**39,088**
Senior Leadership Team	735,046	981,275	**982,785**	850,118	232,486	-	**1,082,604**	118,702	**1,201,306**	(218,521)	**982,785**
Finance	461,847	549,375	**634,716**	361,681	116,825	-	**478,505**	171,087	**649,592**	(14,876)	**634,716**
Corporate Services and Regulatory Affairs	471,330	413,375	**613,340**	285,230	249,679	-	**534,909**	78,431	**613,340**	-	**613,340**
Corporate communications	73,281	62,336	**39,208**	37,608	1,600	-	**39,208**	-	**39,208**	-	**39,208**
Industry associations	60,000	60,000	**60,000**	-	60,000	-	**60,000**	-	**60,000**	-	**60,000**
Regulatory fees and costs	191,400	126,661	**269,641**	-	269,641	-	**269,641**	-	**269,641**	-	**269,641**
Bad debts- BGI Impairment	-	127,869	**96,810**	-	96,810	-	**96,810**	-	**96,810**	-	**96,810**
Corp - IT/Prj Mgr	-	17,321	**178,156**	257,194	21,676	-	**278,870**	-	**278,870**	(100,714)	**178,156**
	2,072,554	2,381,737	**2,913,745**	1,807,790	1,067,317	-	**2,875,107**	372,749	**3,247,856**	(334,111)	**2,913,745**
OTHER DIRECT COSTS											
Special projects	1,071,941	646,236	**961,167**	201,797	759,370	-	**961,167**	-	**961,167**	-	**961,167**
	1,071,941	646,236	**961,167**	201,797	759,370	-	**961,167**	-	**961,167**	-	**961,167**
TOTAL DIRECT EXPENSES	$ 9,835,517	$ 9,260,857	**$ 11,038,339**	$ 5,974,698	$ 4,661,227	$ 344,887	**$ 10,980,812**	$ 1,766,703	**$ 12,747,515**	$(1,709,176)	**11,038,339**

SCHEDULE OF DIRECT AND INDIRECT EXPENSES - DETAIL

	2015 Budget	2015 Projected	2016 Budget	Direct Salaries, Wages & Benefits	Direct Goods & Services	City SLA	Total Gross Direct & Indirect Costs	Allocation of Indirect Costs to Operational Accounts	Fully Allocated Direct & Indirect Costs	Allocation to CDM, Affiliate, Capital or Billable Projects	Net Direct and Indirect Costs
INDIRECT GENERAL AND ADMINISTRATIVE EXPENSES											
Retiree benefits	$ 90,577	$ 83,765	**$ 160,916**	-	85,200	75,716	**$ 160,916**	-	**160,916**	-	**$ 160,916**
Records management, mail, telephone & duplicating	12,815	14,511	**13,828**	-	-	22,408	**22,408**	(8,580)	**13,828**	-	**13,828**
Insurance and risk management	104,602	86,000	**82,522**	-	-	82,522	**82,522**	-	**82,522**	-	**82,522**
Treasury and accounting	-	-	**-**	-	-	87,039	**87,039**	(87,039)	**-**	-	**-**
Purchasing and dispatch	-	-	**-**	172,435	8,020	-	**180,455**	(180,455)	**-**	-	**-**
Management information systems	-	-	**-**	-	-	898,448	**898,448**	(898,448)	**-**	-	**-**
Property charges	-	-	**118,939**	-	-	696,063	**696,063**	(577,124)	**118,939**	-	**118,939**
Legal	15,000	13,600	**12,190**	-	-	12,190	**12,190**	-	**12,190**	-	**12,190**
Human resources	-	-	**-**	-	-	66,905	**66,905**	(66,905)	**-**	-	**-**
Brantford Energy Corp Management Fees	124,190	148,775	**103,357**	-	103,357	-	**103,357**	-	**103,357**	-	**103,357**
Other	24,480	22,988	**23,000**	-	23,000	-	**23,000**	-	**23,000**	-	**23,000**
Fleet recovery	-	0	**-**	61,110	(265,748)	180,071	**(24,567)**	24,567	**-**	-	**-**
TOTAL INDIRECT EXPENSES	$ 371,664	$ 369,639	**$ 514,752**	$ 233,545	$ (46,171)	$ 2,121,362	**$ 2,308,736**	$(1,793,984)	**$ 514,752**	$ -	**$ 514,752**
CDM ADMINISTRATIVE EXPENSES							**$ -**	$ 27,281	**$ 27,281**	**$ (27,281)**	**$ -**
GRAND TOTAL OM&A EXPENSES	$ 10,207,181	$ 9,630,496	**$ 11,553,091**	$ 6,208,243	$ 4,615,056	$ 2,466,249	**$ 13,289,548**	$ -	**$ 13,262,267**	$(1,709,176)	**$ 11,553,091**
Transfer to billable/recoverable projects	$ 370,148	$ 364,351	**$ -**	$ -	$ -	$ -	**$ -**	$ -	**$ -**	$ 383,159	
Transfer to capital projects	-	-	**-**	-	-	-	**-**	-	**-**	1,092,620	
Transfer to OPA CDM Programs	24,300	24,835	**-**	-	-	-	**-**	-	**-**		
Transfer to affiliate - BEC							**-**			46,486	
Transfer to affiliate - BHI							**-**			115,625	
Transfer to affiliate - BGI										71,286	
	394,448	389,186	**-**	-	-	-	**-**	-	**-**	1,709,176	
NET TOTAL OM&A EXPENSES	$ 10,601,629	$ 10,019,682	**$ 11,553,091**	$ 6,208,243	$ 4,615,056	$ 2,466,249	**$ 13,289,548**	$ -	**$ 13,262,267**	$ -	**$ 11,553,091**

BRANTFORD POWER INC.
2016 BUDGET AND MULTI-YEAR FORECAST
SCHEDULE OF REGULATORY ASSETS AND LIABILITIES

	2014 Actual	2015 Budget	2015 Projected	2016 Budget	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast
SUMMARY BY MAJOR REGULATORY ACCOUNT CATEGORY								
RETAIL SETTLEMENT VARIANCE ACCOUNTS								
Wholesale Market Service Charges	$ (988,870)	$ (1,047,843)	$ (1,253,431)	**$ (1,559,311)**	$ (922,812)	$ (909,441)	$ (905,614)	$ (906,727)
Transmission - Network	874,193	1,983,395	553,574	**266,980**	696,848	695,156	695,717	698,201
Transmission - Connection	73,446	414,967	211,228	**130,942**	94,991	93,604	93,597	93,933
Cost of Power	(2,821,457)	(2,148,006)	(2,796,606)	**(2,118,063)**	(1,257,723)	(1,297,884)	(1,353,720)	(1,388,760)
Global Adjustment	3,034,422	537,604	3,101,929	**2,521,031**	2,025,581	2,083,567	2,165,856	2,237,580
One Time	290,236	293,341	292,755	**295,078**	-	-	-	-
	461,970	33,458	109,449	**(463,343)**	636,885	665,002	695,836	734,227
OTHER DEFERRAL AND VARIANCE ACCOUNTS								
Stranded Meters	2,332,050	1,629,564	1,626,662	**867,832**	93,770	93,980	94,189	94,399
Smart Meter Entity Charge	24,327	(6,200)	(7,340)	**(4,033)**	(1,968)	(1,759)	(803)	1
	2,356,376	1,623,364	1,619,322	**863,799**	91,802	92,221	93,386	94,400
General								
CDM Lost Revenue	114,639	122,683	18,920	**80,792**	62,346	376,557	740,742	1,164,226
Embedded LDC Revenue Difference	171,716	174,076	173,631	**175,397**	-	-	-	-
Retailer Cost Variance Account	48,103	73,800	74,719	**93,478**	36,240	54,796	73,634	92,759
IFRS transition costs and early disposals	253,997	272,696	301,825	**344,518**	-	-	-	-
Recovery of regulatory assets	(90,863)	(94,347)	(278,526)	**(303,860)**	(258,868)	(15,184)	10,743	19,593
	497,593	548,908	290,569	**390,325**	(160,282)	416,169	825,119	1,276,578
Other								
Regulatory future income tax liability	664,215	(1,829,896)	1,351,605	**1,777,974**	2,371,334	2,731,722	3,033,482	3,316,437
Other regulatory assets	277	19,248	277	**277**	-	-	-	-
	664,492	(1,810,648)	1,351,882	**1,778,251**	2,371,334	2,731,722	3,033,482	3,316,437
Total	3,980,431	395,082	3,371,222	**2,569,032**	2,939,739	3,905,114	4,647,823	5,421,642
Summary								
Total Regulatory Assets	6,643,746	5,521,374	7,707,125	**6,554,299**	5,541,392	6,129,382	6,907,960	7,717,129
Total Regulatory Liabilities	(2,663,315)	(5,126,292)	(4,335,903)	**(3,985,267)**	(2,601,653)	(2,224,268)	(2,260,137)	(2,295,487)
Net Assets(Liabilities)	$ 3,980,431	$ 395,082	$ 3,371,222	**$ 2,569,032**	$ 2,939,739	$ 3,905,114	$ 4,647,823	$ 5,421,642
Group 1	195,510	(231,547)	(442,912)	**(981,489)**	440,363	1,026,375	1,447,321	1,918,046
Group 2	3,120,706	2,456,525	2,462,529	**1,772,547**	128,042	147,017	167,020	187,159
Group 3	664,215	(1,829,896)	1,351,605	**1,777,974**	2,371,334	2,731,722	3,033,482	3,316,437
Net Assets(Liabilities)	$ 3,980,431	$ 395,082	$ 3,371,222	**$ 2,569,032**	$ 2,939,739	$ 3,905,114	$ 4,647,823	$ 5,421,642

BRANTFORD POWER INC.
2016 BUDGET AND MULTI-YEAR FORECAST
RATIOS AND LOAD AND CUSTOMER STATISTICS

	2014 Actual	2015 Budget	2015 Projected	2016 Budget	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast
Current Ratio (OILC not less than 1.1:1)	1.9	2.3	2.0	**1.9**	2.0	2.0	2.1	2.1
Quick Ratio	0.6	0.7	0.6	**0.4**	0.5	0.4	0.6	0.5
Working Capital	15,894,599	19,210,183	17,405,719	**14,885,607**	18,198,727	17,103,805	20,184,411	19,913,102
Debt to Equity (OILC <60%)	52.1%	51.9%	50.3%	**56.9%**	58.1%	57.2%	58.2%	56.9%
Debt to Equity (RBC <60% exclude City Note)	32.3%	32.7%	30.1%	**42.4%**	44.9%	43.5%	45.6%	43.8%
Debt to Equity (Regulatory)	52.1%	51.9%	50.3%	**56.9%**	58.1%	57.2%	58.2%	56.9%
Dividend Payout Ratio (Regular and Special)	29.1%	56.9%	38.9%	**103.2%**	57.4%	58.2%	49.6%	40.9%
Return on Equity	6.6%	3.3%	6.3%	**2.5%**	3.4%	3.3%	3.8%	4.5%
Return on Regulatory Equity	6.6%	3.3%	6.3%	**2.5%**	3.4%	3.3%	3.8%	4.5%
Return on Assets	2.4%	1.2%	2.4%	**0.9%**	1.1%	1.1%	1.3%	1.5%
Debt Service Coverage (OILC no less than 1.2:1)	3.45	1.41	1.93	**(0.62)**	1.44	1.58	(7.33)	1.76
OM&A Cost per Customer	$ 237.10	$ 258.14	$ 243.50	**$ 289.69**	$ 297.19	$ 298.39	$ 293.57	$ 293.68
Distribution Revenue per Customer	$ 412.19	$ 413.05	$ 413.46	**$ 417.96**	$ 455.95	$ 460.14	$ 466.78	$ 473.84
Rate Base Growth	-	3.3%	2.1%	**12.4%**	12.3%	2.0%	1.7%	1.1%
STAFFING LEVELS (FULL TIME EQUIVALENT)								
Senior Leadership Team	5.67	5.00	5.00	**5.00**	5.00	5.00	5.00	5.00
Corporate Services	-	-	0.13	**2.00**	2.00	2.00	2.00	2.00
Customer Service	13.74	14.58	15.33	**12.92**	13.92	15.42	13.42	12.42
Engineering	8.00	8.00	8.67	**9.00**	9.00	9.00	9.00	9.00
Finance	3.67	5.50	4.54	**6.50**	7.00	5.00	5.00	5.00
Operations	17.24	17.00	17.67	**18.50**	19.00	19.00	19.00	19.00
Regulatory	2.00	3.00	2.38	**3.00**	3.00	3.00	3.00	3.00
Communications	0.70	1.00	0.69	**0.69**	0.69	0.69	0.69	0.69
Settlement	5.00	5.00	3.33	**5.00**	5.00	5.00	5.00	5.00
	56.01	59.08	57.73	**62.61**	64.61	64.11	62.11	61.11
Conservation and Demand Management	2.00	2.00	1.63	**3.00**	3.00	3.00	3.00	3.00
	58.01	61.08	59.35	**65.61**	67.61	67.11	65.11	64.11
Full Time	54.28	55.00	54.00	**58.25**	59.00	59.00	59.00	59.00
Part-Time	1.41	1.42	1.42	**1.42**	1.42	1.42	1.42	1.42
Contract	2.32	4.66	3.93	**5.94**	7.19	6.69	4.69	3.69
	58.01	61.08	59.35	**65.61**	67.61	67.11	65.11	64.11

BRANTFORD POWER INC.
2016 BUDGET AND MULTI-YEAR FORECAST
RATIOS AND LOAD AND CUSTOMER STATISTICS

	2014 Actual	2015 Budget	2015 Projected	2016 Budget	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast
ENERGY SOLD (Mwh)								
Residential	284,160	287,739	289,767	**289,643**	291,579	293,256	294,963	296,725
General Service < 50 KW	100,424	103,236	103,769	**104,467**	104,862	105,149	105,458	105,790
General Service > 50 KW (includes Back-up/Standby)	537,759	494,508	504,978	**494,432**	485,490	478,599	478,939	479,221
Street lighting	7,430	7,396	7,175	**7,342**	7,342	7,342	7,342	7,342
Sentinel lighting	451	420	434	**433**	423	412	401	390
Unmetered Scattered Load	1,561	1,503	1,517	**1,506**	1,491	1,480	1,470	1,460
	931,785	894,802	907,640	**897,823**	891,187	886,238	888,573	890,928
ENERGY PURCHASED (Mwh)								
Independent Electricity Systems Operator & Others	961,319	921,646	934,869	**924,758**	917,923	912,825	915,230	917,656
LINE LOSSES/UNACCOUNTED FOR ENERGY	(29,534)	(26,844)	(27,229)	**(26,935)**	(26,736)	(26,587)	(26,657)	(26,728)
LINE LOSSES/UNACCOUNTED FOR ENERGY %	(3.0%)	(3.0%)	(3.0%)	**(3.0%)**	(3.0%)	(3.0%)	(3.0%)	(3.0%)
DEMAND (KW's)								
General Service > 50 KW	1,568,023	1,443,544	1,516,664	**1,465,784**	1,405,361	1,389,482	1,391,516	1,393,664
Street lighting	22,581	22,520	21,902	**21,930**	21,930	21,930	21,930	21,930
	1,590,604	1,466,064	1,538,566	**1,487,714**	1,427,291	1,411,412	1,413,446	1,415,594
CUSTOMER COUNT								
Residential	35,351	35,886	35,884	**36,195**	36,476	36,760	37,045	37,333
General Service < 50 KW	2,760	2,794	2,799	**2,819**	2,838	2,858	2,878	2,897
General Service > 50 KW (includes Back-up/Standby)	430	437	438	**443**	449	454	459	465
Unmetered Scattered Load	435	424	429	**424**	421	418	415	412
	38,976	39,541	39,550	**39,881**	40,184	40,489	40,797	41,107
CONNECTIONS								
Street lighting	10,075	10,080	10,080	**10,080**	10,080	10,080	10,080	10,080
Sentinel lighting	623	588	621	**614**	598	582	567	552
	10,698	10,668	10,701	**10,694**	10,678	10,662	10,647	10,632
CUSTOMER COUNT BY SUPPLY OPTION								
Distributor - Regulated Price Plan	35,715	36,117	36,481	**36,785**	37,063	37,342	37,626	37,910
Distributor - Market Price	255	239	254	**257**	260	263	266	269
Retailer - Distributor Consolidated Billing	3,006	3,185	2,815	**2,839**	2,861	2,884	2,905	2,928
Retailer - Retailer Consolidated Billing	-	-	-	**-**	-	-	-	-
	38,976	39,541	39,550	**39,881**	40,184	40,489	40,797	41,107
ENERGY GENERATORS								
BCPI Load Transfer	1	1	1	**1**	1	1	1	1
Embedded Generator	1	1	1	**1**	1	1	1	1
RESOP	1	1	1	**1**	1	1	1	1
Fit/Microfit	106	125	125	**140**	155	170	185	200
	109	128	128	**143**	158	173	188	203

Attachment 1-SEC-9: 2016 KPIs

BRANTFORD POWER INC.
2015
KEY PERFORMANCE INDICATORS

Stakeholder	KPI	Measure	2015 Targets	2015 Actuals
Shareholder	Earnings	Net Income	$1,876,000	$3,104,000
	Efficiency	Cost Per Customer (Note with BGI Impairment – 2015 Actual would be $246.24)	$244.02	$242.76
Customer	Reliability (excluding loss of supply)	Duration – total minutes of outage (5yr Rolling Average)	832,956 Minutes	1,183,438 Minutes
		Frequency – Total Number of Incidents (5yr Rolling Average)	28,816 Incidents	38,547 Incidents
	Satisfaction	Score on Annual Customer Satisfaction Survey	Two Top Boxes Total 76%	76%
		Score on Transactional Customer Satisfaction Survey Q1 - Overall, how satisfied are you with Brantford Power?	Two Top Boxes	N/A (2015 -75%)
Employee	Safety	Lost Time Accidents	Nil	Nil
	Engagement	Staff Survey Score (3.4 in 2013)	3.5	3.3
Regulator	Rate Application	Cost of Service Application completed and filed by OEB Due Date	N/A	N/A
	Compliance	Major non-compliance issues with IESO, Measurement Canada, ESA & OEB (Note 1)	Nil	Nil
	Conservation	Net Annual Energy Savings –- Target (Mwh) (New CDM Framework)	5,200 Mwh	7,400 (Mwh)

1. Major non-compliance is defined as an event which results in significant negative impact to BPI's brand or presents a significant financial risk to the business

BRANTFORD POWER INC.
2016
KEY PERFORMANCE INDICATORS
FIRST QUARTER UPDATE

Stakeholder	KPI	Measure	2016 APPROVED	2016 Q1 TARGET	2016 Q1 RESULTS
Shareholder	Earnings	Net Income	$1,028.000	$482,000	$952,000
	Efficiency	Cost Per Customer	$289.69	$69.49	$56.34
Customer	Reliability (excluding loss of supply)	Duration – total minutes of outage (5yr Rolling Average)	1,013,520 Minutes	253,380 Minutes	462,199 Minutes
		Frequency – Total Number of Customer Outages (5yr Rolling Average)	34,005 Incidents	8,501 Incidents	15,551 Incidents
	Satisfaction	Score on Transactional Customer Satisfaction Survey Q1 - Overall, how satisfied are you with Brantford Power?	76%	76%	75.3%
Employee	Safety	Lost Time Accidents	Nil	Nil	Nil
	Engagement	Staff Survey Score (3.4 in 2013)	3.2	N/A Scheduled for Q3	N/A Scheduled for Q3
Regulator	Rate Application **(Note 1)**	Cost of Service Application completed and filed by OEB Due Date	April 29, 2016	April 29, 2016	May 4, 2016
	Compliance	Major non-compliance issues with IESO, Measurement Canada, ESA & OEB **(Note 2)**	Nil	Nil	Nil
	Conservation	Net Annual Energy Savings –- Target (Mwh) (New CDM Framework)	11,000 (Mwh)	2,750 (Mwh)	Not Available

1. **Rate application filing** was planned for Q2 – since the results are known, it has been reflected on the Q1 reporting.
2. **Major non-compliance** is defined as an event which results in significant negative impact to BPI's brand or presents a significant financial risk to the business

Attachment 2-SEC-15: Asset Health/Failure

2-SEC-15

Asset Type	Total #	Condition Health Index (CHI) Excellent (4)	Good (3)	Poor (2)	Very Poor (1)	Probability of Failure Unlikely (1)	Somewhat Likely (2)	Likely (3)	Almost Certain (4)	Assets Replaced (Actual) 2013	2014	2015	Assets Replaced (Forecast) 2016	2017	2018	2019	2020	2021
Example A	50	10	15	20	5	10	15	20	5	2	1	1	1	2	1	1	1	1
Pole (number of poles)	10041	5302	3584	996	159	6728	2737	477	99	23	13	19	30	25	30	25	30	25
Primary Conductor (segments)	6495	6468	27	0	0	6278	91	50	44	0	0	0	1	0	0	0	0	0
Secondary Bus (segments)	7702	7626	59	11	6	7314	108	57	223	0	2000 m	0	0	0	0	0	0	0
Structure	2030	1745	241	44	0	1528	376	88	38	7	16	12	11	10	8	8	8	8
Switch	956	909	27	19	1	881	52	20	3	0	0	3	3	3	2	2	2	2
Transformer	3364	2139	1084	134	7	2200	1030	124	10	4	6	15	8	8	8	8	8	8

Attachment 2-STAFF-9: ODM Results

G3E_FNO	G3E_FID	INSTALL_DATE	AGE	ESL	INSPECT_DATE	YEARS_SINCE_INSP	CHI	FOLLOWING_LC	ODM_ERL	POF	CRI	COF	RISK_INDEX	RISK_LEVEL
208	1439958	01/01/1988	28	59	29/02/2016 9:31:49 AM	3	3	YES	35	1	30.5921052631579	2	30.5921052631579	1
208	1439959	01/01/1977	39	55	29/02/2016 3:03:33 PM	3	4	YES	20	2	21.5131578947368	2	43.0263157894737	2
208	1439960	01/01/1969	47	65	01/03/2016 11:11:50 AM	3	2	YES	22	2	77.9605263157895	4	155.921052631579	3
208	1439961	01/01/1992	24	59	01/03/2016 11:10:54 AM	3	3	YES	39	1	30.5921052631579	2	30.5921052631579	1
208	1439962	01/01/2005	11	59	01/03/2016 11:09:46 AM	3	4	YES	52	1	30.5921052631579	2	30.5921052631579	1
208	1439963	01/01/2002	14	59	01/03/2016 11:01:22 AM	3	4	YES	49	1	30.5921052631579	2	30.5921052631579	1
208	1439964	01/01/1985	31	59	01/03/2016 11:01:57 AM	3	2	YES	32	1	77.9605263157895	4	77.9605263157895	2
208	1439965	01/01/2004	12	59	01/03/2016 10:59:36 AM	3	4	YES	51	1	77.9605263157895	4	77.9605263157895	2
208	1439966	01/01/1985	31	59	01/03/2016 10:57:38 AM	3	3	YES	32	1	30.5921052631579	2	30.5921052631579	1
208	1439967	01/01/1988	28	59	29/02/2016 9:30:49 AM	3	4	YES	35	1	77.9605263157895	4	77.9605263157895	2
208	1439968	01/01/1951	65	51	26/02/2016 1:09:04 PM	3	3	BETTER	17	2	21.5131578947368	2	43.0263157894737	2
208	1439969	08/12/2008 11:33:24 AM	8	62	26/02/2016 1:09:40 PM	3	4	YES	58	1	30.5921052631579	2	30.5921052631579	1
208	1439970	01/01/1978	38	65	26/02/2016 1:09:26 PM	3	3	WORSE	17	2	30.5921052631579	2	61.1842105263158	2
208	1439971	01/01/2007	9	56	23/03/2016 9:14:49 AM	3	3	YES	51	1	77.9605263157895	4	77.9605263157895	2
208	1439972	01/01/2008	8	56	23/03/2016 9:14:52 AM	3	4	YES	52	1	77.9605263157895	4	77.9605263157895	2
208	1439973	01/01/1990	26	59	26/02/2016 1:16:32 PM	3	2	YES	37	1	30.5921052631579	2	30.5921052631579	1
208	1439974	01/01/1987	29	70	01/03/2016 9:28:43 AM	3	3	WORSE	20	2	30.5921052631579	2	61.1842105263158	2
208	1439975	01/01/2008	8	56	23/03/2016 9:15:11 AM	3	4	YES	52	1	30.5921052631579	2	30.5921052631579	1
208	1439976	02/06/2009 9:37:15 AM	7	56	23/03/2016 9:15:56 AM	3	3	YES	53	1	30.5921052631579	2	30.5921052631579	1
208	1439977	08/12/2008	8	55	23/03/2016 9:15:57 AM	3	4	YES	51	1	21.5131578947368	2	21.5131578947368	1
208	1439978	08/12/2008 11:03:23 AM	8	59	23/03/2016 9:16:07 AM	3	4	YES	55	1	21.5131578947368	2	21.5131578947368	1
208	1439979	01/01/1987	29	62	01/03/2016 9:27:37 AM	3	2	YES	37	1	30.5921052631579	2	30.5921052631579	1
208	1439980	01/01/2008	8	59	23/03/2016 9:16:42 AM	3	3	YES	55	1	30.5921052631579	2	30.5921052631579	1
208	1439981	01/01/1998	18	59	26/02/2016 1:18:10 PM	3	4	YES	45	1	30.5921052631579	2	30.5921052631579	1
208	1439982	01/01/2008	8	65	26/02/2016 1:17:48 PM	3	3	WORSE	21	2	30.5921052631579	2	61.1842105263158	2
208	1439983	01/01/2008	8	59	26/02/2016 1:18:37 PM	3	3	YES	55	1	30.5921052631579	2	30.5921052631579	1
208	1439984	01/01/2006	10	59	26/02/2016 1:19:47 PM	3	3	YES	53	1	77.9605263157895	4	77.9605263157895	2
208	1440001	01/01/2004	12	59	22/03/2016 9:27:10 AM	3	4	YES	51	1	30.5921052631579	2	30.5921052631579	1
208	1440005	01/01/2005	11	51	01/03/2016 9:43:20 AM	3	3	YES	44	1	30.5921052631579	2	30.5921052631579	1
208	1440007	01/01/2002	14	59	15/03/2016 2:46:43 PM	3	3	YES	49	1	30.5921052631579	2	30.5921052631579	1
208	1440020	01/01/2003	13	59	01/03/2016 10:29:14 AM	3	3	YES	50	1	30.5921052631579	2	30.5921052631579	1
208	1440032	01/01/2005	11	62	01/03/2016 10:40:09 AM	3	3	YES	55	1	30.5921052631579	2	30.5921052631579	1
208	1440038	01/01/2006	10	70	29/02/2016 9:50:43 AM	0	4	YES	61	1	0.789473684210526	1	0.789473684210526	1
208	1440069	01/01/2005	11	51	01/03/2016 9:43:22 AM	3	4	YES	44	1	30.5921052631579	2	30.5921052631579	1
208	1440071	01/01/2006	10	51	01/03/2016 9:41:44 AM	3	3	YES	45	1	30.5921052631579	2	30.5921052631579	1
208	1440072	01/01/2006	10	51	01/03/2016 9:41:29 AM	3	3	YES	45	1	30.5921052631579	2	30.5921052631579	1
208	1440074	01/01/2002	14	70	22/03/2016 9:25:10 AM	0	3	WORSE	22	2	10.2631578947368	1	20.5263157894737	1
208	1440079	01/01/2006	10	59	15/03/2016 2:56:46 PM	3	3	YES	53	1	30.5921052631579	2	30.5921052631579	1
208	1440080	01/01/2006	10	59	15/03/2016 2:55:50 PM	3	3	YES	53	1	30.5921052631579	2	30.5921052631579	1
208	1440081	01/01/2006	10	59	22/03/2016 9:41:14 AM	3	4	YES	53	1	30.5921052631579	2	30.5921052631579	1
208	1440082	01/01/2006	10	59	22/03/2016 9:41:29 AM	3	4	YES	53	1	30.5921052631579	2	30.5921052631579	1
208	1440083	01/01/2006	10	59	26/02/2016 2:46:21 PM	3	4	YES	53	1	30.5921052631579	2	30.5921052631579	1
208	1440084	01/01/2006	10	59	26/02/2016 2:46:05 PM	3	4	YES	53	1	68.8815789473684	4	68.8815789473684	2
208	1440085	01/01/2006	10	59	26/02/2016 2:45:43 PM	3	4	YES	53	1	30.5921052631579	2	30.5921052631579	1
208	1440086	01/01/2006	10	59	26/02/2016 2:45:24 PM	3	4	YES	53	1	30.5921052631579	2	30.5921052631579	1
208	1440087	01/01/2006	10	59	26/02/2016 2:45:08 PM	3	4	YES	53	1	30.5921052631579	2	30.5921052631579	1

Attachment 3-EP-27: Weather Normalization Regression Model

Filed as live excel

Attachment 3-VECC-21: Final 2015 Verified Results Report

Attachment 3-VECC-22: LRAMVA Support

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BRANTFORD POWER INC.

LRAMVA SUPPORT

September 08, 2016

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REVIEWED BY: BART BURMAN, MBA BA.SC. P.ENG

Table of Contents

Executive Summary

Burman Energy Consultants group has calculated Brantford Power's LRAMVA value for the period of 2013 through 2014 to be a total of $158,612.14 . This number was derived by calculating the total LRAM value of $416,446.76 and subtracting the already forcasted lost revenue already collected of $257,834.62 . Brantford Power's EB-2011-0147 load forecast did not include the adjustments for LRAM (2006 - 2010) as a result Burman Energy recommends an LRAM claim of $118,295.06 for 2013. This is consistent with Brantford Power's OEB decision 2014 dated No.

Introduction

Since the completion of Third Tranche CDM programs and reporting, LDCs across Ontario have sought to recover revenues lost to successful CDM programming. The mechanism that enables this recovery is the Lost Revenue Adjustment Mechanism (LRAM).

On April 26, 2012, new Board-issued CDM Guidelines were enacted that provide updated LRAM details. For CDM programs delivered within the 2011 to 2014 term, the Board established the Lost Revenue Adjustment Variance Account (LRAMVA). This account captures the variance between the Board-approved CDM forecast and the actual CDM results.

The variance calculated from this comparison must be recorded in separate sub-accounts per the applicable customer rate classes.

LDCs must apply for the disposition of the balance in the LRAMVA as part of their cost of service (COS) applications or on an annual basis, as part of their IRM rate applications.

The LRAM mechanism determines persistent CDM impacts realized after 2010, for those distributors whose load forecast has not been updated.

Terms

Term	Description
Persistence	CDM savings during the subsequent years after the first year savings.
Extension Framework	The conservation period between 2011 and 2015
Conservation First Framework	The conservation period between 2015 and 2020.
CDM	Conservation and Demand Management
LRAM	Lost Revenue Adjustment Mechanism
LRAMVA	Lost Revenue Adjustment Mechanism Variance Account
COS	Cost of Service
IRM	Incentive Regulation Model

Scope of Work

Specifically, Burman Energy will perform the following in its work undertaking:

1) Collect and outline savings for the following data sets:
    i. CDM Results for programs as applicable for the LRAMVA period.
    ii. Forecasted savings for Conservation and Demand Management programs (Last Approved).
2) Collect additional data as outlined:
    i. LDC volumetric distribution rates for LRAMVA years.
    ii. Completed Retrofit projects for years for which retrofit savings are reported.
3) Calculate by initiative and year the lost revenue values.
4) Calculate the currently recovered lost revenue from the load forecast.
5) Outline the net LRAMVA values by year and overall.
6) Provide summary report with supporting information.

Lost Revenue Adjustment Mechanism History

From 2005 to the end of 2010, distributors delivered CDM programs either through approved distribution rate funding by way of the third installment of their incremental market adjusted revenue requirement ("MARR"), or through contracts with the IESO. Some distributors received incremental distribution rate funding separate from MARR. To promote the participation in and the delivery of CDM programs by distributors, the Board made available an LRAM regardless of whether the CDM programs were funded by the IESO or through distribution rates.

Lost Revenue Adjustment Mechanism Outline

In preparation of this document, Burman Energy performed this analysis in compliance with Guidelines for Electricity Distributor Conservation and Demand Management EB-2012-0003 with specific reference to the following:

> 13.6 LRAM & Shared Savings Mechanism for Pre-CDM Code Activities
>
> The Board notes that the Filing Requirements for Transmission and Distribution Applications state the following:
>
> > Distributors intending to file an LRAM or SSM application for CDM Programs funded through distribution rates, or an LRAM application for CDM Programs funded by the IESO between 2005 and 2010, shall do so as part of their 2012 rate application filings, either cost-of-service or IRM. If a distributor does not file for the recovery of LRAM or SSM amounts in its 2012 rate application, it will forego the opportunity to recover LRAM or SSM for this legacy period of CDM activity.
>
> The 2008 CDM Guidelines state as follows: "lost revenues are only accruable until new rates (based on a new revenue requirement and load forecast) are set by the Board, as the CDM savings would be assumed to be incorporated in the load forecast at that time". The intent of the LRAM in the 2008 CDM Guidelines was to keep electricity distributors revenue neutral for CDM activities implemented by the distributor during the years in which its rates were set using the incentive regulation mechanism, and that future LRAM claims should be unnecessary once a distributor rebases and updates its load forecast.
>
> The Board therefore expects that LRAM for pre-2011 CDM activities should be completed with the 2012 rate applications, outside of persisting historical CDM impacts realized after 2010 for those distributors whose load forecast has not been updated as part of a cost of service application.

This summary is extracted from the "Guidelines for Electricity Distributor Conservation and Demand Management" (EB-2012-0003). This document can be found at:
http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2012-0003/CDM_Guidelines_Electricity_Distributor.pdf

Lost Revenue Adjustment Mechanism Variance Account Outline

With specific reference to the following:

13.2 LRAM Mechanism for 2011- 2014

The Board will adopt an approach for LRAM for the 2011-2014 CDM period that is similar to that adopted in relation to natural gas distributor DSM activities. The Board will authorize the establishment of an LRAM variance account (“LRAMVA”) to capture, at the customer rate-class level, the difference between the following:

i. The results of actual, verified impacts of authorized CDM activities undertaken by electricity distributors between 2011-2014 for both Board-Approved CDM programs and IESO-Contracted Province-Wide CDM programs in relation to activities undertaken by the distributor and/or delivered for the distributor by a third party under contract (in the distributor’s franchise area); and

ii. The level of CDM program activities included in the distributor’s load forecast (i.e. the level embedded into rates).

Distributors will generally be expected to include a CDM component in their load forecast in cost of service proceedings to ensure that its customers are realizing the true effects of conservation at the earliest date possible date and to mitigate the variance between forecasted revenue losses and actual revenue losses. If the distributor has included a CDM load reduction in its distribution rates, the amount of the forecast that was adjusted for CDM at the rate class level would be compared to the actual DCM results verified by an independent third party for each year of the CDM program (i.e., 2011 to 2014) in accordance with the IESO’s EM&V Protocols as set out in Section 6.1 of the CDM Code. The variance calculated from this comparison result in a credit or a debit to the ratepayers at the customer rate class level in the LRAMVA. The LRAM amount is determined by applying, by customer class, the distributor’s Board-approved variable distribution charge applicable to the class to the volumetric variance (positive or negative) described in the paragraph above. The calculated lost revenues will be recorded in the LRAMVA. Distributors will be expected to report the balance in the LRAMVA as part of the reporting and record-keeping requirements on an annual basis.

This summary is extracted from the "Guidelines for Electricity Distributor Conservation and Demand Management" (EB-2012-0003). This document can be found at:
http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2012-0003/CDM_Guidelines_Electricity_Distributor.pdf

Summary Of Lost Revenue Adjustments

LRAMVA Summary

Burman Energy Consultants Group Inc. (Burman Energy) has prepared the following LRAMVA tables, representing the variance amount to be recorded in the LRAM Variance Account. The amount is the calculated result of the lost revenues by customer class based on the volumetric impact of the load reductions arising from the CDM measures implemented, multiplied by Brantford Power's Board-approved variable distribution changes applicable to the customer rate class in which the volumetric variance occurred. The calculations provided by Burman Energy do not include carrying charges or adjustments based on CDM reductions as included in any CDM Load reduction forecast.

Results Year	Lost Revenue Adjustment Mechanism Year					
	2013	2014				
2014	$ -	$ 161,302				
2013	$ 49,886	$ 52,858				
2012	$ 39,376	$ 41,899				
2011	$ 35,292	$ 35,834				
Total	$ 124,554	$ 291,893				
Forecast	$ 125,662	$ 132,172				
Net	$ (1,108)	$ 159,721				
Variance			$ 158,612			

Results Year	Lost Revenue Adjustment Mechanism Summary By Rate Class					
	Residential	GS <= 50 kW	GS > 50 kW			Total
2014	$ 67,300	$ 43,794	$ 180,799			$ 291,893
2013	$ 40,546	$ 32,017	$ 51,990			$ 124,554
Total	$ 107,846	$ 75,811	$ 232,789			$ 416,447
Forecast	$ 109,726	$ 69,495	$ 78,614			$ 257,835
Net	$ (1,880)	$ 6,317	$ 154,175			$ 158,612

LRAM Summary

Burman Energy recommends an LRAM claim of $118,295.06 as none of the requested LRAM has been subject to any previous approvals and were not included in Brantford Power's last load forecast. This is consistent with Brantford Power's OEB decision EB-2011-0147 dated April 19, 2012. The below table represents LRAM calculations for persistence of 2006-2010 programs for 2013 only.

Results Year	Lost Revenue Adjustment Mechanism Year					
	2013					
2010	$ 27,772					
2009	$ 41,887					
2008	$ 24,584					
2007	$ 18,208					
2006	$ 5,845					
Total	$ 118,295					

OEB decision EB-2011-0147 dated April 19, 2012:

> The Board will approve an LRAM claim of $515,439.19, comprised of the effect of programs launched in 2005 to 2010 and persistence thereof in 2006 to 2010. Although the CDM Guideline states that lost revenues are only accruable until new rates (based on a new revenue requirement and load forecast) are set by the Board, as the savings would be assumed to be incorporated in the load forecast at that time, the Board has acknowledged (PowerStream decision EB-2011-0005 and PUC decision EB-2011-0101) that the 2004 NAC based load forecast underpinning Brantford's cost of service rates does not include the impact of Brantford's CDM programs. The Board also notes that with the exception of 2008, Brantford was under IRM during the subject time period and did not otherwise receive compensation for lost revenues from these programs. The Board will not approve lost revenues arising from these programs in 2011, as it is premature to do so and inconsistent with the CDM Guidelines.

Reference Material

The following IESO documents were used to prepare the LRAMVA calculations:

i. [2006-2014]_RATES_DATABASE_FROM TARIFFS.xls
ii. 2011-2014 Brantford Power Results with Persistence.xls
iii. Brantford Power [2013-2014] Retrofit Project Lists
iv. 2006-2010 Brantford Power Results with Persistence.xls

Methodology

Burman Energy would like to present a summary of the methodology used to calculate the LRAMVA figures in this report for the purposes of auditing.

Burman Energy collects the following information as the sources for the values calculated in this report:

- Rate Database documents from the Ontario Energy Board (OEB) website for all years that are being calculated.
- Final CDM results and their persistence into future years received directly from the IESO or from the Local Distributor.
- Retrofit & High Performance New Construction (HPNC) project data with kW, kWh and Rate Class information for each project.
- The forecasted CDM results from the distributors most recently approved Cost of Service application (COS).

Burman Energy takes the results of each initiative where the savings for the LRAMVA report period are not equal to zero and enters the figures into the report. The values entered into the report are organized by results year, rate class, and then initiative. The rate classes outlined here are examples and may not be actual customer classes for this local distribution company.

Results from 2014
Residential
HVAC Incentives
RESIDIENTIAL TOTAL
GS Less Than 50 kW
Retrofit
GS LESS THAN 50 KW TOTAL
GS Greater Than 50 kW
Retrofit
GS GREATER THAN 50 KW TOTAL
Large Use
Retrofit
LARGE USE TOTAL
RESULTS FROM 2014 TOTAL

The results for Retrofit and HPNC items are initially collected for all rate classes then using verified project savings the result savings are divided into the appropriate rate classes.

Year	Application Type	LDC	Demand Savings	Energy Savings	Rate Class	Sector
2014	Retrofit	ntford Power	491.37	3,212,976	GS>50	Industrial
2014	Retrofit	ntford Power	98.43	713,220	GS<50	Business

kW	GS>50	83.31%	GS<50	16.69%	Large Use	0.00%
kWh		81.83%		18.17%		0.00%

Volumetric distribution rates are derived by using the rate database provided on the OEB website directly as they appear. These volumetric distribution rates are collected for each rate class for the years during the LRAMVA reporting period and one year prior are entered into the report along with their effective date. Burman Energy uses the effective date to create a weighted volumetric rate for each of the calendar years (Jan1st through Dec 31st) years in the reporting period. A summary of the calculation is presented below:

$$Weighted\ Rate = \left(Rate_{old} * \left(\frac{Months\ at\ Old}{12}\right)\right) + \left(Rate_{new} * \left(\frac{Months\ at\ New}{12}\right)\right)$$

The weighted volumetric rate is multiplied by the savings metric selected by rate class (the Residential and GS<50 metric is kWh and the GS>50 and Large Use metric is kW). The resulting figure is then subject to global modifiers based on initiative (eg. Demand Response 3 is taken at a factor of 0% due to the type of savings it provides).

$$LRAM(kW) = Weighted\ Rate * Modifier\%_{If\ Applicable} * \left((kW_{Per\ Month} * Months\ at\ old\ Rate) + (kW_{Per\ Month} * Months\ at\ New\ Rate)\right)$$

$$LRAM\ (kWh) = Weighted\ Rate * Modifier\%_{If\ Applicable} * kWh_{Annual}$$

The totals are outlined at the bottom of each section with a summary by rate class presented near the bottom of the table for comparison to the forecasted figures.

If the distributor had forecasted CDM savings Burman Energy takes the values and applies same methods outlined for the savings results to calculate the total lost revenue that has already been recovered for the reporting period.

The recovered lost revenue is subtracted from the calculated LRAM resulting in the net figures or Variance. These figures are outlined by reporting period year and as an overall.

Supporting Attachments

Brantford Power Inc. LRAMVA CALCULATIONS
OPA Conservation & Demand Management Programs
Initiative Results at End-User Level

Initiative Name	2012	2013				2014			
	Volumetric Rate	Net Summer Peak Demand Savings (kW)	Net Energy Savings (kWh)	Distribution Volumetric Rate (Effective Date: May 1)	2013 LRAMVA	Net Summer Peak Demand Savings (kW)	Net Energy Savings (kWh)	Distribution Volumetric Rate (Effective Date: Mar 1)	2014 LRAMVA
LRAM CDM Results and Persistence									
Results from 2014									
Residential									
Appliance Exchange	0.0138			0.0138		24.24	43,224.47	0.0142	$ 610.91
Appliance Retirement	0.0138			0.0138		15.39	96,339.67	0.0142	$ 1,361.60
Bi-Annual Retailer Event	0.0138			0.0138		58.36	891,691.62	0.0142	$ 12,602.57
Conservation Instant Coupon Booklet	0.0138			0.0138		20.01	242,189.62	0.0142	$ 3,422.95
Home Assistance Program	0.0138			0.0138		15.49	193,418.54	0.0142	$ 2,733.65
HVAC Incentives	0.0138			0.0138		197.14	363,072.12	0.0142	$ 5,131.42
Residential Demand Response	0.0138			0.0138		351.52	0.00	0.0142	$ -
RESIDENTIAL TOTAL		**0.00**	**0**		**$ -**	**682.15**	**1,829,936**		**$ 25,863.10**
GS Less Than 50 kW									
Commercial Demand Response	0.0065			0.0065		2.79	0.00	0.0067	$ -
Demand Response 3	0.0065			0.0065		63.26	0.00	0.0067	$ -
Direct Install Lighting	0.0065			0.0065		117.41	431,458.36	0.0067	$ 2,876.39
Energy Audit	0.0065			0.0065		13.37	65,273.57	0.0067	$ 435.16
High Performance New Construction	0.0065			0.0065		1.80	16,137.95	0.0067	$ 107.59
LDC Pilots	0.0065			0.0065		29.41	266,087.85	0.0067	$ 1,773.92
LDC Program Enabled Savings	0.0065			0.0065		31.90	256,700.00	0.0067	$ 1,711.33
Retrofit	0.0065			0.0065		98.85	717,914.13	0.0067	$ 4,786.09
Time-of-Use Savings	0.0065			0.0065		468.84	0.00	0.0067	$ -
GS LESS THAN 50 KW TOTAL		**0.00**	**0**		**$ -**	**827.61**	**1,753,572**		**$ 11,690.48**
GS Greater Than 50 kW									
Demand Response 3	2.6043			2.6043		286.22	0.00	2.9678	$ -
PSUI	2.6043			2.6043		3,053.70	27,003,930.00	2.9678	$ 106,533.21
Retrofit	2.6043			2.6043		493.45	3,234,122.19	2.9678	$ 17,214.94
GS GREATER THAN 50 KW TOTAL		**0.00**	**0**		**$ -**	**3,833.38**	**30,238,052**		**$ 123,748.15**
RESULTS FROM 2014 TOTAL		**0.00**	**0**		**$ -**	**5,343.15**	**33,821,560**		**$ 161,301.73**
Results from 2013									
Residential									
Annual Coupons	0.0138	3.75	55,920.45	0.0138	$ 771.70	3.75	55,920.45	0.0142	$ 790.34
Appliance Exchange	0.0138	25.48	45,441.10	0.0138	$ 627.09	25.48	45,441.10	0.0142	$ 642.23
Appliance Retirement	0.0138	15.65	102,323.89	0.0138	$ 1,412.07	15.65	102,323.89	0.0142	$ 1,446.18
Bi-Annual Retailer Events	0.0138	8.59	124,644.22	0.0138	$ 1,720.09	8.59	124,644.22	0.0142	$ 1,761.64
Conservation Instant Coupon Booklet	0.0138	0.01	171.00	0.0138	$ 2.36	0.01	171.00	0.0142	$ 2.42
Home Assistance Program	0.0138	27.38	227,870.60	0.0138	$ 3,144.61	27.28	225,921.43	0.0142	$ 3,193.02
HVAC	0.0138	167.70	281,617.98	0.0138	$ 3,886.33	167.70	281,617.98	0.0142	$ 3,980.20
HVAC Incentives	0.0138	8.94	15,705.91	0.0138	$ 216.74	8.94	15,705.91	0.0142	$ 221.98
peaksaverPLUS	0.0138	149.67	0.00	0.0138	$ -	0.00	0.00	0.0142	$ -
RESIDENTIAL TOTAL		**407.17**	**853,695**		**$ 11,780.99**	**257.40**	**851,746**		**$ 12,038.01**
GS Less Than 50 kW									
DR-3	0.0065	68.66	916.83	0.0065	$ -	0.00	0.00	0.0067	$ -
Energy Audit	0.0065	44.10	242,478.78	0.0065	$ 1,576.11	44.10	242,478.78	0.0067	$ 1,616.53
Energy Audit Funding	0.0065	17.63	96,901.54	0.0065	$ 629.86	17.63	96,901.54	0.0067	$ 646.01
LDC Program Enabled Savings	0.0065	418.50	591,166.00	0.0065	$ 3,842.58	418.50	591,166.00	0.0067	$ 3,941.11
Retrofit	0.0065	63.73	356,583.17	0.0065	$ 2,317.79	61.93	350,405.00	0.0067	$ 2,336.03
Small Business Lighting	0.0065	72.66	236,782.49	0.0065	$ 1,539.09	72.66	236,782.49	0.0067	$ 1,578.55
GS LESS THAN 50 KW TOTAL		**685.28**	**1,524,829**		**$ 9,905.43**	**614.82**	**1,517,734**		**$ 10,118.23**
GS Greater Than 50 kW									
DR-3	2.6043	346.66	7,893.72	2.6043	$ -	0.00	0.00	2.9678	$ -
High Performance New Construction	2.6043	113.30	642,162.32	2.6043	$ 3,540.73	113.30	642,162.32	2.9678	$ 3,952.56
Retrofit	2.6043	789.04	3,965,997.80	2.6043	$ 24,658.76	766.75	3,897,282.80	2.9678	$ 26,749.25
GS GREATER THAN 50 KW TOTAL		**1,249.00**	**4,616,054**		**$ 28,199.48**	**880.05**	**4,539,445**		**$ 30,701.81**
RESULTS FROM 2013 TOTAL		**2,341.46**	**6,994,578**		**$ 49,885.90**	**1,752.27**	**6,908,925**		**$ 52,858.05**
Results from 2012									
Residential									
Appliance Exchange	0.0138	0.55	968.49	0.0138	$ 13.37	0.55	968.49	0.0142	$ 13.69
Appliance Retirement	0.0138	23.53	159,035.39	0.0138	$ 2,194.69	23.53	159,035.39	0.0142	$ 2,247.70
Bi-Annual Retailer Event	0.0138	10.74	194,308.03	0.0138	$ 2,681.45	10.74	194,308.03	0.0142	$ 2,746.22
Conservation Instant Coupon Booklet	0.0138	1.67	10,144.32	0.0138	$ 139.99	1.67	10,144.32	0.0142	$ 143.37
Home Assistance Program	0.0138	31.85	284,039.90	0.0138	$ 3,919.75	31.84	283,716.50	0.0142	$ 4,009.86
HVAC	0.0138	4.78	9,321.60	0.0138	$ 128.64	4.78	9,321.60	0.0142	$ 131.75
HVAC Incentives	0.0138	194.28	330,910.08	0.0138	$ 4,566.56	194.28	330,910.08	0.0142	$ 4,676.86
RESIDENTIAL TOTAL		**267.40**	**988,728**		**$ 13,644.44**	**267.38**	**988,404**		**$ 13,969.45**
GS Less Than 50 kW									
Direct Install Lighting	0.0065	68.80	269,847.78	0.0065	$ 1,754.01	68.80	269,847.78	0.0067	$ 1,798.99
Retrofit	0.0065	84.65	685,735.97	0.0065	$ 4,457.28	83.84	682,391.11	0.0067	$ 4,549.27
GS LESS THAN 50 KW TOTAL		**153.46**	**955,584**		**$ 6,211.29**	**152.64**	**952,239**		**$ 6,348.26**
GS Greater Than 50 kW									
High Performance New Construction	2.6043	0.82	794.30	2.6043	$ 25.62	0.82	794.30	2.9678	$ 28.60
Retrofit	2.6043	623.78	3,856,221.20	2.6043	$ 19,494.27	617.79	3,837,411.44	2.9678	$ 21,552.73
GS GREATER THAN 50 KW TOTAL		**624.60**	**3,857,015**		**$ 19,519.90**	**618.61**	**3,838,206**		**$ 21,581.33**
RESULTS FROM 2012 TOTAL		**1,045.46**	**5,801,327**		**$ 39,375.63**	**1,038.64**	**5,778,849**		**$ 41,899.04**
Results from 2011									
Residential									
Appliance Exchange	0.0138	9.14	12,869.39	0.0138	$ 177.60	5.28	9,418.08	0.0142	$ 133.11
Appliance Retirement	0.0138	34.52	250,242.24	0.0138	$ 3,453.34	33.84	249,635.50	0.0142	$ 3,528.18
Bi-Annual Retailer Event	0.0138	12.98	229,054.81	0.0138	$ 3,160.96	12.98	229,054.81	0.0142	$ 3,237.31
Conservation Instant Coupon Booklet	0.0138	9.53	151,983.30	0.0138	$ 2,097.37	9.53	151,983.30	0.0142	$ 2,148.03
HVAC Incentives	0.0138	244.29	451,579.31	0.0138	$ 6,231.79	244.29	451,579.31	0.0142	$ 6,382.32
peaksaverPLUS	0.0138	84.21	142.13	0.0138	$ -	0.00	0.00	0.0142	$ -
RESIDENTIAL TOTAL		**394.68**	**1,095,871**		**$ 15,121.06**	**305.92**	**1,091,671**		**$ 15,428.95**
GS Less Than 50 kW									
Direct Install Lighting	0.0065	157.67	408,272.04	0.0065	$ 2,653.77	123.18	307,652.26	0.0067	$ 2,051.02
Electricity Retrofit Incentive Program	0.0065	141.34	842,904.60	0.0065	$ 5,478.88	141.34	842,904.60	0.0067	$ 5,619.36
peaksaverPLUS	0.0065	3.20	5.10	0.0065	$ -	0.00	0.00	0.0067	$ -
Retrofit	0.0065	179.33	1,195,030.56	0.0065	$ 7,767.70	179.33	1,195,030.56	0.0067	$ 7,966.87
GS LESS THAN 50 KW TOTAL		**481.54**	**2,446,212**		**$ 15,900.35**	**443.85**	**2,345,587**		**$ 15,637.25**
GS Greater Than 50 kW									
High Performance New Construction	2.6043	46.50	113,316.50	2.6043	$ 1,453.20	46.50	113,316.50	2.9678	$ 1,622.23
Retrofit	2.6043	90.17	614,079.80	2.6043	$ 2,817.81	90.17	614,079.80	2.9678	$ 3,145.56
GS GREATER THAN 50 KW TOTAL		**136.67**	**727,396**		**$ 4,271.01**	**136.67**	**727,396**		**$ 4,767.79**
RESULTS FROM 2011 TOTAL		**1,012.88**	**4,269,480**		**$ 35,292.42**	**886.44**	**4,164,655**		**$ 35,833.99**
Results from 2010									
Residential									
Cool Savings Rebate	0.0138	208.41	317,554.64	0.0138	$ 4,382.25			0.0142	
Every Kilowatt Counts Power Savings Event	0.0138	11.26	115,869.09	0.0138	$ 1,598.99			0.0142	
Great Refrigerator Roundup	0.0138	76.96	486,030.86	0.0138	$ 6,707.23			0.0142	
Multi-Family Energy Efficiency Rebates	0.0138	15.31	180,733.39	0.0138	$ 2,494.12			0.0142	
peaksaverPLUS	0.0138	251.48	841.09	0.0138	$ -			0.0142	
RESIDENTIAL TOTAL		**563.42**	**1,101,029**		**$ 15,182.59**	**0.00**	**0**		**$ -**
GS Less Than 50 kW									
peaksaverPLUS	0.0065	12.16	19.40	0.0065	$ -			0.0067	
Power Savings Blitz	0.0065	65.57	201,230.70	0.0065	$ 1,308.00			0.0067	
GS LESS THAN 50 KW TOTAL		**77.73**	**201,250**		**$ 1,308.00**	**0.00**	**0**		**$ -**
GS Greater Than 50 kW									
High Performance New Construction	2.6043	103.87	236,826.47	2.6043	$ 3,246.14			2.9678	
Retrofit	2.6043	257.11	1,450,436.37	2.6043	$ 8,034.95			2.9678	
GS GREATER THAN 50 KW TOTAL		**360.98**	**1,687,263**		**$ 11,281.09**	**0.00**	**0**		**$ -**
RESULTS FROM 2010 TOTAL		**1,002.13**	**2,989,542**		**$ 27,771.68**	**0.00**	**0**		**$ -**
Results from 2009									
Residential									
Cool Savings Rebate	0.0138	138.02	208,879.50	0.0138	$ 2,882.54			0.0142	
Every Kilowatt Counts Power Savings Event	0.0138	36.33	348,825.11	0.0138	$ 4,813.79			0.0142	
Great Refrigerator Roundup	0.0138	40.26	288,827.48	0.0138	$ 3,985.82			0.0142	
peaksaverPLUS	0.0138	445.09	778.70	0.0138	$ -			0.0142	
RESIDENTIAL TOTAL		**659.70**	**847,311**		**$ 11,682.14**	**0.00**	**0**		**$ -**
GS Less Than 50 kW									

	2012	2013				2014			
Initiative Name	Volumetric Rate	Net Summer Peak Demand Savings (kW)	Net Energy Savings (kWh)	Distribution Volumetric Rate (Effective Date: May 1)	2013 LRAMVA	Net Summer Peak Demand Savings (kW)	Net Energy Savings (kWh)	Distribution Volumetric Rate (Effective Date: Mar 1)	2014 LRAMVA
peaksaverPLUS	0.0065	4.48	7.15	0.0065	$ -			0.0067	
Power Savings Blitz	0.0065	704.42	2,748,182.91	0.0065	$ 17,863.19			0.0067	
GS LESS THAN 50 KW TOTAL		**708.90**	**2,748,190**		**$ 17,863.19**	**0.00**	**0**		**$ -**
GS Greater Than 50 kW									
High Performance New Construction	2.6043	32.86	74,907.86	2.6043	$ 1,026.80			2.9678	
Retrofit	2.6043	362.05	2,440,227.27	2.6043	$ 11,314.50			2.9678	
GS GREATER THAN 50 KW TOTAL		**394.90**	**2,515,135**		**$ 12,341.30**	**0.00**	**0**		**$ -**
RESULTS FROM 2009 TOTAL		**1,763.50**	**6,110,636**		**$ 41,886.63**	**0.00**	**0**		**$ -**
Results from 2008									
Residential									
Cool Savings Rebate	0.0138	106.45	168,039.34	0.0138	$ 2,318.94			0.0142	
Every Kilowatt Counts Power Savings Event	0.0138	40.40	720,856.67	0.0138	$ 9,947.82			0.0142	
Great Refrigerator Roundup	0.0138	42.34	404,195.65	0.0138	$ 5,577.90			0.0142	
peaksaverPLUS	0.0138	286.12	4,567.22	0.0138	$ -			0.0142	
Summer Sweepstakes	0.0138	138.39	344,216.73	0.0138	$ 4,750.19			0.0142	
RESIDENTIAL TOTAL		**613.70**	**1,641,876**		**$ 22,594.86**	**0.00**	**0**		**$ -**
GS Less Than 50 kW									
peaksaverPLUS	0.0065	3.20	5.10	0.0065	$ -			0.0067	
GS LESS THAN 50 KW TOTAL		**3.20**	**5**		**$ -**	**0.00**	**0**		**$ -**
GS Greater Than 50 kW									
High Performance New Construction	2.6043	3.02	2,551.18	2.6043	$ 94.45			2.9678	
Retrofit	2.6043	60.62	308,271.10	2.6043	$ 1,894.53			2.9678	
GS GREATER THAN 50 KW TOTAL		**63.64**	**310,822**		**$ 1,988.98**	**0.00**	**0**		**$ -**
RESULTS FROM 2008 TOTAL		**680.54**	**1,952,703**		**$ 24,583.84**	**0.00**	**0**		**$ -**
Results from 2007									
Residential									
Cool & Hot Savings Rebate	0.0138	97.56	151,023.21	0.0138	$ 2,084.12			0.0142	
Every Kilowatt Counts	0.0138	33.35	906,674.06	0.0138	$ 12,512.10			0.0142	
Great Refrigerator Roundup	0.0138	20.14	175,333.48	0.0138	$ 2,419.60			0.0142	
peaksaverPLUS	0.0138	29.64	39.22	0.0138	$ -			0.0142	
Social Housing Pilot	0.0138	10.16	86,375.11	0.0138	$ 1,191.98			0.0142	
RESIDENTIAL TOTAL		**190.84**	**1,319,445**		**$ 18,207.80**	**0.00**	**0**		**$ -**
GS Less Than 50 kW									
peaksaverPLUS	0.0065	2.56	4.08	0.0065	$ -			0.0067	
GS LESS THAN 50 KW TOTAL		**2.56**	**4**		**$ -**	**0.00**	**0**		**$ -**
RESULTS FROM 2007 TOTAL		**193.40**	**1,319,449**		**$ 18,207.80**	**0.00**	**0**		**$ -**
Results from 2006									
Residential									
Cool & Hot Savings Rebate	0.0138	90.33	97,471.27	0.0138	$ 1,345.10			0.0142	
Every Kilowatt Counts	0.0138	29.83	326,087.39	0.0138	$ 4,500.01			0.0142	
RESIDENTIAL TOTAL		**120.16**	**423,559**		**$ 5,845.11**	**0.00**	**0**		**$ -**
RESULTS FROM 2006 TOTAL		**120.16**	**423,559**		**$ 5,845.11**	**0.00**	**0**		**$ -**
Summary By Rate Class (2011 - 2014)									
Residential	0.0138	1,069.25	2,938,294.14	0.0138	$ 40,546.50	1,512.86	4,761,757.42	0.0142	$ 67,299.50
General Service Less Than 50 kW	0.0065	1,320.28	4,926,624.87	0.0065	$ 32,017.07	2,038.93	6,569,131.98	0.0067	$ 43,794.21
General Service Greater Than 50 kW	2.6043	2,010.27	9,200,465.63	2.6043	$ 51,990.39	5,468.70	39,343,099.34	2.9678	$ 180,799.09
SUMMARY BY RATE CLASS (2011 - 2014) TOTAL		**4,399.80**	**17,065,385**		**$ 124,553.95**	**9,020.50**	**50,673,989**		**$ 291,892.81**
Summary By Rate Class (2005 - 2010)									
Residential	0.0138	2,147.82	5,333,219.24	0.0138	$ 73,512.50	0.00	0.00	0.0142	$ -
General Service Less Than 50 kW	0.0065	792.39	2,949,449.34	0.0065	$ 19,171.19	0.00	0.00	0.0067	$ -
General Service Greater Than 50 kW	2.6043	819.52	4,513,220.25	2.6043	$ 25,611.37	0.00	0.00	2.9678	$ -
SUMMARY BY RATE CLASS (2005 - 2010) TOTAL		**3,759.74**	**12,795,889**		**$ 118,295.06**	**0.00**	**0**		**$ -**
LRAM CDM RESULTS AND PERSISTENCE TOTAL		**8,159.54**	**29,861,273.46**		**$ 242,849.02**	**9,020.50**	**50,673,988.74**		**$ 291,892.81**
Load Forecast CDM Component									
Residential	0.0138	0.00	3,928,130.30	0.0138	**$ 54,208.20**	0.00	3,928,130.30	0.0142	**$ 55,517.57**
General Service Less Than 50 kW	0.0065	0.00	5,278,065.33	0.0065	**$ 34,307.42**	0.00	5,278,065.33	0.0067	**$ 35,187.10**
General Service Greater Than 50 kW	2.6043	14,263.65	5,602,979.85	2.6043	**$ 37,146.81**	14,263.65	5,602,979.85	2.9678	**$ 41,467.51**
LOAD FORECAST CDM COMPONENT TOTAL		**14,263.65**	**14,809,175.48**		**$ 125,662.44**	**14,263.65**	**14,809,175.48**		**$ 132,172.19**
BRANTFORD POWER INC. NET LRAMVA TOTAL (LRAM [2011 - 2014] MINUS FORECAS		**-9,863.84**	**2,256,209.16**		**-$ 1,108.48**	**-5,243.15**	**35,864,813.26**		**$ 159,720.62**
Lost Revenue Adjustment Mechanism Variance									$158,612.14
Lost Revenue Adjustment Mechanism									$118,295.06

METHODOLOGY

All results are at the end-user level (not including transmission and distribution losses)

EQUATIONS:

PRESCRIPTIVE MEASURES/PROJECTS:

Gross Savings = Activity * Per Unit Assumption

Net Savings = Gross Savings * Net-to-Gross Ratio

All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)

ENGINEERED/CUSTOM PROJECTS:

Gross Savings = Reported Savings * Realization Rate

Net Savings = Gross Savings * Net-to-Gross Ratio

All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)

DEMAND RESPONSE:

Peak Demand: Gross Savings = Net Savings = contracted MW at contributor level * Provincial contracted to ex ante ratio

Energy: Gross Savings = Net Savings = provincial ex post energy savings * LDC proportion of total provincial contracted MW

All savings are annualized (i.e. the savings are the same regardless of the time of year a participant began offering DR)

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Consumer Program				
1	Appliance Retirement	Includes both retail and home pickup stream; Retail stream allocated based on average of residential throughput; Home pickup stream directly attributed by postal code or customer selection	Savings are considered to begin in the year the appliance is picked up.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
2	Appliance Exchange	When postal code information is provided by customer, results are directly attributed to the LDC. When postal code is not available, results allocated based on average of residential throughput	Savings are considered to begin in the year that the exchange event occurred	
3	HVAC Incentives	Results directly attributed to LDC based on customer postal code	Savings are considered to begin in the year that the installation occurred	
4	Conservation Instant Coupon Booklet	LDC-coded coupons directly attributed to LDC; Otherwise results are allocated based on average of residential throughput	Savings are considered to begin in the year in which the coupon was redeemed.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level. Reported results are presented with verified per unit assumptions and net-to-gross ratio from Bi-Annual Retailer Event and Conservation Instant Coupon Booklet initiatives.
5	Bi-Annual Retailer Event	Results are allocated based on average of residential throughput	Savings are considered to begin in the year in which the event occurs.	
6	Retailer Co-op	When postal code information is provided by the customer, results are directly attributed. If postal code information is not available, results are allocated based on average of residential throughput.	Savings are considered to begin in the year of the home visit and installation date.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level. Reported results are presented with verified per unit assumptions and net-to-gross ratio from Bi-Annual Retailer Event and Conservation Instant Coupon Booklet initiatives.
7	Residential Demand Response	Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists	Savings are considered to begin in the year the device was installed and/or when a customer signed a ***peaksaver*** PLUS™ participant agreement.	**Peak demand savings** are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. **Energy savings** are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year and accounts for any "snapback" in energy consumption experienced after the event. Savings are assumed to **persist** for only 1 year, reflecting that savings will only occur if the resource is activated.

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
8	Residential New Construction	Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system; Reported results are presented with forecast assumptions as per the business case.	Savings are considered to begin in the year of the project completion date.	**Peak demand and energy savings** are determined using a measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Business Program				
9	Efficiency: Equipment Replacement	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping	Savings are considered to begin in the year of the actual project completion date on the iCON CRM system.	**Peak demand and energy savings** are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
10	Direct Installed Lighting	Results are directly attributed to LDC based on the LDC specified on the work order	Savings are considered to begin in the year of the actual project completion date.	**Peak demand and energy savings** are determined using the verified measure level per unit assumptions multiplied by the uptake of each measure accounting for the realization rate for both peak demand and energy to reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings take into account net-to-gross factors such as free-ridership and spillover for both peak demand and energy savings at the program level (net).
11	Existing Building Commissioning Incentive	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year of the actual project completion date.	**Peak demand and energy savings** are determined by the total savings for a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
12	New Construction and Major Renovation Incentive	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, reported results are presented with reported assumptions.	Savings are considered to begin in the year of the actual project completion date.	
13	Energy Audit	Projects are directly attributed to LDC based on LDC identified in the application	Savings are considered to begin in the year of the audit date.	**Peak demand and energy savings** are determined by the total savings resulting from an audit as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
14	Commercial Demand Response (part of the Residential program schedule)	Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists	Savings are considered to begin in the year the device was installed and/or when a customer signed a ***peaksaver*** PLUS™ participant agreement.	**Peak demand savings** are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. **Energy savings** are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year. Savings are assumed to **persist** for only 1 year, reflecting that savings will only occur if the resource is activated.
15	Demand Response 3 (part of the Industrial program schedule)	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st of the relevant year, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year in which the contributor signed up to participate in demand response.	**Peak demand savings** are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. **Energy savings** are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.
Industrial Program				
16	Process & System Upgrades	Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system.	Savings are considered to begin in the year in which the incentive project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
17	Monitoring & Targeting	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the incentive project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
18	Energy Manager	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the project was completed by the energy manager. If no date is specified the savings will begin the year of the Quarterly Report submitted by the energy manager.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping	Savings are considered to begin in the year of the actual project completion date on the iCON CRM system.	**Peak demand and energy savings** are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
20	Demand Response 3	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st of the relevant year, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year in which the contributor signed up to participate in demand response.	**Peak demand savings** are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. **Energy savings** are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.
Home Assistance Program				
21	Home Assistance Program	Results are directly attributed to LDC based on LDC identified in the application; reported results are presented with forecast assumptions as per the business case.	Savings are considered to begin in the year in which the measures were installed.	**Peak demand and energy savings** are determined using the measure level per unit assumption multiplied by the uptake of each measure (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Legacy Programs Completed in Current Year				
22	Electricity Retrofit Incentive Program	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which a project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). **If energy savings are not available,** an estimate is made based on the kWh to kW ratio in the provincial results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
23	High Performance New Construction	Results are directly attributed to LDC based on customer data provided to the OPA from the gas utility.	Savings are considered to begin in the year in which a project was completed.	
24	Toronto Comprehensive	Program run exclusively in Toronto Hydro-Electric System Limited service territory		

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
25	Multifamily Energy Efficiency Rebates	Results are directly attributed to LDC based on LDC identified in the application	Savings are considered to begin in the year in which a project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). **If energy savings are not available,** an estimate is made based on the kWh to kW ratio in the provincial results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
26	Data Centre Incentive Program	Program run exclusively in PowerStream Inc. service territory		
27	EnWin Green Suites	Program run exclusively in ENWIN Utilities Ltd. service territory		

Attachment 3-VECC-23-A: Results with Persistence

Filed in excel

Attachment 3-VECC-23-B: Results with Persistence (2014)

Filed in live excel

Attachment 3-VECC-26: CDM Template

Filed in Live Excel

Attachment 4-EP-44: 2015 Tax Return

200

Canada Revenue Agency / Agence du revenu du Canada

T2 Corporation Income Tax Return

055 Do not use this area

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal *Income Tax Act* and *Income Tax Regulations*. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or Guide T4012, *T2 Corporation – Income Tax Guide*.

Identification

Business number (BN) **001** 86585 8773 RC0001

Corporation's name
002 Brantford Power Inc.

Address of head office
Has this address changed since the last time we were notified? .... **010** 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 011 to 018.)
011 84 MARKET SQUARE
012 PO BOX 308
City: **015** BRANTFORD
Province, territory, or state: **016** ON
Country (other than Canada): **017** CA
Postal code/Zip code: **018** N3T 5N8

Mailing address (if different from head office address)
Has this address changed since the last time we were notified? .... **020** 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 021 to 028.)
021 c/o
022
023
City: **025**
Province, territory, or state: **026**
Country (other than Canada): **027**
Postal code/Zip code: **028**

Location of books and records (if different from head office address)
Has the location of books and records changed since the last time we were notified? .... **030** 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 031 to 038.)
031 84 MARKET SQUARE
032 PO BOX 308
City: **035** BRANTFORD
Province, territory, or state: **036** ON
Country (other than Canada): **037** CA
Postal code/Zip code: **038** N3T 5N8

040 **Type of corporation at the end of the tax year**
1 [X] Canadian-controlled private corporation (CCPC)
2 [ ] Other private corporation
3 [ ] Public corporation
4 [ ] Corporation controlled by a public corporation
5 [ ] Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change .... **043** ________ YYYY MM DD

To which tax year does this return apply?
Tax year start **060** 2015-01-01 (YYYY MM DD)
Tax year-end **061** 2015-12-31 (YYYY MM DD)

Has there been an acquisition of control to which subsection 249(4) applies since the tax year start on line 060? .. **063** 1 Yes [ ] 2 No [X]
If **yes**, provide the date control was acquired .... **065** ________ YYYY MM DD

Is the date on line 061 a deemed tax year-end according to subsection 249(3.1)? .... **066** 1 Yes [ ] 2 No [X]

Is the corporation a professional corporation that is a member of a partnership? .... **067** 1 Yes [ ] 2 No [X]

Is this the first year of filing after:
Incorporation? .... **070** 1 Yes [ ] 2 No [X]
Amalgamation? .... **071** 1 Yes [ ] 2 No [X]
If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? .... **072** 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? .... **076** 1 Yes [ ] 2 No [X]

Is this the final return up to dissolution? .... **078** 1 Yes [ ] 2 No [X]

If an election was made under section 261, state the functional currency used .... **079** ________

Is the corporation a resident of Canada?
080 1 Yes [X] 2 No [ ] If **no**, give the country of residence on line 081 and complete and attach Schedule 97.
081 ________

Is the non-resident corporation claiming an exemption under an income tax treaty? .... **082** 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:
085
1 [ ] Exempt under paragraph 149(1)(e) or (l)
2 [ ] Exempt under paragraph 149(1)(j)
3 [ ] Exempt under paragraph 149(1)(t)
4 [ ] Exempt under other paragraphs of section 149

Do not use this area
095 **096** **898**

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

		Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160	X	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders who own voting shares?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164	X	14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165	X	15
Is the corporation claiming a loss or deduction from a tax shelter?	166		T5004
Is the corporation a member of a partnership for which a partnership account number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)?	168		22
Did the corporation own any shares in one or more foreign affiliates in the tax year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the *Income Tax Regulations*?	170		29
Did the corporation have a total amount over $1 million of reportable transactions with non-arm's length non-residents?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		———
Does the corporation earn income from one or more Internet webpages or websites?	180		88
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202	X	2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203	X	3
Is the corporation claiming any type of losses?	204	X	4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205	X	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) does the corporation have aggregate investment income at line 440?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210	X	10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming deductible reserves (other than transitional reserves under section 34.2)?	213	X	13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal, provincial, or territorial foreign tax credits, or any federal logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231	X	31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232		T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	33/34/35
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	———
Is the corporation claiming a surtax credit?	237		37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

Attachments – continued from page 2

	Line	Yes	Schedule
Did the corporation have any foreign affiliates in the tax year?	271		T1134
Did the corporation own or hold specified foreign property where the total cost amount of all such property, at any time in the year, was more than CAN$100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265	X	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268		53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54

Additional information

	Line	1 Yes	2 No
Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270	X	
Is the corporation inactive?	280		X

What is the corporation's main revenue-generating business activity? 221122 Electric Power Distribution

Specify the principal products mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

Line	Product or service	Line	%
284	ELECTRICITY DISTRIBUTION	285	100.000 %
286		287	%
288		289	%

	Line	1 Yes	2 No
Did the corporation immigrate to Canada during the tax year?	291		X
Did the corporation emigrate from Canada during the tax year?	292		X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293		

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible 294 ____ YYYY MM DD

If the corporation's major business activity is construction, did you have any subcontractors during the tax year? 295 1 Yes ☐ 2 No ☐

Taxable income

	Line			
Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.	300		3,274,219	A
Deduct: Charitable donations from Schedule 2	311	2,600		
Gifts to Canada, a province, or a territory from Schedule 2	312			
Cultural gifts from Schedule 2	313			
Ecological gifts from Schedule 2	314			
Gifts of medicine from Schedule 2	315			
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320			
Part VI.1 tax deduction*	325			
Non-capital losses of previous tax years from Schedule 4	331	3,271,619		
Net capital losses of previous tax years from Schedule 4	332			
Restricted farm losses of previous tax years from Schedule 4	333			
Farm losses of previous tax years from Schedule 4	334			
Limited partnership losses of previous tax years from Schedule 4	335			
Taxable capital gains or taxable dividends allocated from a central credit union	340			
Prospector's and grubstaker's shares	350			
Subtotal		3,274,219 ►	3,274,219	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")				C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355			D
Taxable income (amount C **plus** amount D)	360			
Income exempt under paragraph 149(1)(t)	370			
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)				Z
Taxable income for the year from a personal services business**				Z.1

* This amount is equal to 3.5 times the Part VI.1 tax payable at line 724 on page 8.

** For a taxation year that ends after 2015.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7 . . . . **400** 3,274,219 A

Taxable income from line 360 on page 3, **minus** 100/28 3.57143 of the amount on line 632* on page 7, **minus** 4 times the amount on line 636** on page 7, and **minus** any amount that, because of federal law, is exempt from Part I tax . . . . **405** B

Business limit (see notes 1 and 2 below) C.1

Corporation's business limit amount assigned to related CPCCs by virtue of the rules proposed in the March 22, 2016 Federal Budget (For more information, consult the Help (F1).) C.2

Business limit after assignment (amount C.1 **minus** amount C.2) . . . . ▶ **410** C

Notes:

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year divided by 365, and enter the result on line 410.

2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C ______ x **415** *** 88,142 / 11,250 D = ... E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") . . . . **425** F

Small business deduction

Amount A, B, C, or F, whichever is the least ______ x (Number of days in the tax year before January 1, 2016 / Number of days in the tax year) 365 / 365 x 17 % = ______ 1

Amount A, B, C, or F, whichever is the least ______ x (Number of days in the tax year after December 31, 2015, and before January 1, 2017 / Number of days in the tax year) ______ / 365 x 17.5 % = ______ 2

Total of amounts 1 and 2 (enter amount G on line I on page 7) **430** G

* Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

***** Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from page 3 (line 360 or amount Z, whichever applies)				A
Lesser of amounts B9 and H9 from Part 9 of Schedule 27			B	
Amount K13 from Part 13 of Schedule 27			C	
Personal service business income	432		D	
Amount used to calculate the credit union deduction (amount F from Schedule 17)			E	
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least			F	
Aggregate investment income from line 440 on page 6*			G	
Subtotal (**add** amounts B to G)			►	H
Amount A **minus** amount H (if negative, enter "0")				I
General tax reduction for Canadian-controlled private corporations – Amount I **multiplied** by	13 %			J

Enter amount J on line 638 on page 7.

* Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from page 3 (line 360 or amount Z, whichever applies)				K
Lesser of amounts B9 and H9 from Part 9 of Schedule 27			L	
Amount K13 from Part 13 of Schedule 27			M	
Personal service business income	434		N	
Amount used to calculate the credit union deduction (amount F from Schedule 17)			O	
Subtotal (**add** amounts L to O)			►	P
Amount K **minus** amount P (if negative, enter "0")				Q
General tax reduction – Amount Q **multiplied** by	13 %			R

Enter amount R on line 639 on page 7.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7 . . . . **440** ______ x (26 2 / 3 + 4 x (Number of days in the tax year after 2015) ______ / 365 (Number of days in the tax year)) % = ______ A

Foreign non-business income tax credit from line 632 on page 7 . . . . . . ______ B

Deduct:
Foreign investment income from Schedule 7 . . . . . **445** ______ x (9 1 / 3 − 1 1 / 3 x (Number of days in the tax year after 2015) ______ / 365 (Number of days in the tax year)) % = ______ C

(if negative, enter "0") ______ ▶ ______ D

Amount A **minus** amount D (if negative, enter "0") . . . . . . ______ E

Taxable income from line 360 on page 3 . . . . . . ______ F

Deduct:

Amount from line 400, 405, 410, or 425 on page 4, whichever is the least . . . . . . ______ G

Foreign non-business income tax credit from line 632 on page 7 . . . . ______ x 100 / 35 = ______ H

Foreign business income tax credit from line 636 on page 7 . . . . . . ______ x 4 = ______ I

Subtotal ______ ▶ ______ J

______ K

K x (26 2 / 3 + 4 x Number of days in the tax year after 2015 ______ / Number of days in the tax year 365) % = ______ L

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8) . . . . . . ______ M

Refundable portion of Part I tax – Amount E, L, or M, whichever is the least . . . . . . **450** ______ N

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year . . . . . . **460** ______

Deduct: Dividend refund for the previous tax year . . . . . . **465** ______

______ ▶ ______ O

Add the total of:

Refundable portion of Part I tax from line 450 above . . . . . . ______ P

Total Part IV tax payable from Schedule 3 . . . . . . ______ Q

Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation . . . . . . **480** ______

______ ▶ ______ R

Refundable dividend tax on hand at the end of the tax year – Amount O **plus** amount R . . . . . . **485** ______

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 on page 2 of Schedule 3 . . . . . . 1,000,000 x [(1 / 3) + (5 x (Number of days in the tax year after 2015) ______ / 365 (Number of days in the tax year)) %] = 333,333 S

Refundable dividend tax on hand at the end of the tax year from line 485 above . . . . . . ______ T

Dividend refund – Amount S or T, whichever is less . . . . . . ______ U

Enter amount U on line 784 on page 8.

Part I tax

Base amount Part I tax – Taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38 %* . . **550** ______ A

* If an amount of taxable income for the year from a personal services business has been entered on line Z.1, the result of the following calculation will be added to the amount on line 550:

Amount Z.1 ______ x (Number of days in the taxation year that are after 2015 / Number of days in the taxation year 365) x 5 % = ______ A.1

Recapture of investment tax credit from Schedule 31 . . . . **602** ______ B

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6 . . . . ______ C

Taxable income from line 360 on page 3 . . . . ______ D

Deduct:

Amount from line 400, 405, 410, or 425 on page 4, whichever is the least . . . . ______ E

Net amount (amount D **minus** amount E) . . . . ______ ► ______ F

Refundable tax on CCPC's investment income –

(6 2 / 3 + 4 x (Number of days in the tax year after 2015 ______ / 365 Number of days in the tax year)) % of whichever is less: amount C or amount F . . . . **604** ______ G

Subtotal (**add** amounts A, B, and G) ______ H

Deduct:

Small business deduction from line 430 on page 4		______	I
Federal tax abatement	608	______	
Manufacturing and processing profits deduction from Schedule 27	616	______	
Investment corporation deduction	620	______	
Taxed capital gains **624** ______			
Additional deduction – credit unions from Schedule 17	628	______	
Federal foreign non-business income tax credit from Schedule 21	632	______	
Federal foreign business income tax credit from Schedule 21	636	______	
General tax reduction for CCPCs from amount J on page 5	638	______	
General tax reduction from amount R on page 5	639	______	
Federal logging tax credit from Schedule 21	640	______	
Eligible Canadian bank deduction under section 125.21	641	______	
Federal qualifying environmental trust tax credit	648	______	
Investment tax credit from Schedule 31	652	______	
Subtotal		______ ► ______	J

Part I tax payable – Amount H **minus** amount J . . . . ______ K

Enter amount K on line 700 on page 8.

Privacy statement

Personal information is collected under the *Income Tax Act* to administer tax, benefits, and related programs. It may also be used for any purpose related to the administration or enforcement of the Act such as audit, compliance and the payment of debts owed to the Crown. It may be shared or verified with other federal, provincial/territorial government institutions to the extent authorized by law. Failure to provide this information may result in interest payable, penalties or other actions. Under the *Privacy Act*, individuals have the right to access their personal information and request correction if there are errors or omissions. Refer to Info Source **http://www.cra-arc.gc.ca/gncy/tp/nfsrc/nfsrc-eng.html**, personal information bank CRA PPU 047.

Summary of tax and credits

Federal tax

Part I tax payable from amount K on page 7	700		
Part II surtax payable from Schedule 46	708		
Part III.1 tax payable from Schedule 55	710		
Part IV tax payable from Schedule 3	712		
Part IV.1 tax payable from Schedule 43	716		
Part VI tax payable from Schedule 38	720		
Part VI.1 tax payable from Schedule 43	724		
Part XIII.1 tax payable from Schedule 92	727		
Part XIV tax payable from Schedule 20	728		
Total federal tax			

Add provincial or territorial tax:

Provincial or territorial jurisdiction . . . 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec and Alberta)	760		
Total tax payable	770		A

Deduct other credits:

Investment tax credit refund from Schedule 31	780		
Dividend refund from amount U on page 6	784		
Federal capital gains refund from Schedule 18	788		
Federal qualifying environmental trust tax credit refund	792		
Canadian film or video production tax credit refund (Form T1131)	796		
Film or video production services tax credit refund (Form T1177)	797		
Tax withheld at source	800		
Total payments on which tax has been withheld	801		
Provincial and territorial capital gains refund from Schedule 18	808		
Provincial and territorial refundable tax credits from Schedule 5	812	20,000	
Tax instalments paid	840	99,504	
Total credits	890	119,504	119,504 B

Refund code 894 1 Overpayment 119,504

Balance (amount A **minus** amount B) -119,504

If the result is positive, you have a **balance unpaid**. If the result is negative, you have an **overpayment**. Enter the amount on whichever line applies. Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid . . . . . .

For information on how to make your payment, go to **www.cra-arc.gc.ca/payments**.

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information

910 ______ Branch number

914 ______ Institution number

918 ______ Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? . . . 896 1 Yes ☐ 2 No X

If this return was prepared by a tax preparer for a fee, provide their EFILE number . . . 920

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Certification

I, 950 D'AMBOISE (Last name (print)) 951 BRIAN (First name (print)) 954 CFO & VP Corporate Services (Position, office, or rank),

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 2016-06-09 Date (yyyy/mm/dd) ______ Signature of the authorized signing officer of the corporation 956 (519) 751-3522 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below . . . 957 1 Yes X 2 No ☐

958 ______ Name (print) 959 ______ Telephone number

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français. 990 1

Schedule of Instalment Remittances

Name of corporation contact

Telephone number

Effective interest date	Description (instalment remittance, split payment, assessed credit)	Amount of credit
	Instalment	99,504

Total amount of instalments claimed (carry the result to line 840 of the T2 Return) 99,504 **A**

Total instalments credited to the taxation year per T9 99,504 **B**

Transfer

	Account number	Taxation year end	Amount	Effective interest date	Description
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					

Canada Revenue Agency | Agence du revenu du Canada

SCHEDULE 100

Form identifier 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Corporation's name	Business number	Tax year end Year Month Day
Brantford Power Inc.	86585 8773 RC0001	2015-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
	Assets				
	Total current assets	1599	+	36,695,253	33,641,108
	Total tangible capital assets	2008	+	71,046,079	101,567,323
	Total accumulated amortization of tangible capital assets	2009	–	5,990,842	37,964,718
	Total intangible capital assets	2178	+	1,165,571	641,038
	Total accumulated amortization of intangible capital assets	2179	–	325,552	
	Total long-term assets	2589	+	6,897,781	7,421,346
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	109,488,290	105,306,097
	Liabilities				
	Total current liabilities	3139	+	19,551,962	18,355,823
	Total long-term liabilities	3450	+	48,139,324	47,881,035
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	67,691,286	66,236,858
	Shareholder equity				
	Total shareholder equity (mandatory field)	3620	+	41,797,004	39,069,239
	Total liabilities and shareholder equity	3640	=	109,488,290	105,306,097
	Retained earnings				
	Retained earnings/deficit – end (mandatory field)	3849	=	18,639,595	16,724,891

* Generic item

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SCHEDULE 125

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Corporation's name	Business number	Tax year end Year Month Day
Brantford Power Inc.	86585 8773 RC0001	2015-12-31

Income statement information

Description	GIFI	
Operating name	0001	
Description of the operation	0002	
Sequence number	0003	01

Account	Description	GIFI		Current year	Prior year
	Income statement information				
	Total sales of goods and services	8089	+	21,222,171	20,012,065
	Cost of sales	8518	–		
	Gross profit/loss	8519	=	21,222,171	20,012,065
	Cost of sales	8518	+		
	Total operating expenses	9367	+	17,361,794	18,131,101
	Total expenses (mandatory field)	9368	=	17,361,794	18,131,101
	Total revenue (mandatory field)	8299	+	22,752,929	20,744,651
	Total expenses (mandatory field)	9368	–	17,361,794	18,131,101
	Net non-farming income	9369	=	5,391,135	2,613,550
	Farming income statement information				
	Total farm revenue (mandatory field)	9659	+		
	Total farm expenses (mandatory field)	9898	–		
	Net farm income	9899	=		
	Net income/loss before taxes and extraordinary items	9970	=	5,391,135	2,613,550
	Total other comprehensive income	9998	=	23,312	26,347
	Extraordinary items and income (linked to Schedule 140)				
	Extraordinary item(s)	9975	–		
	Legal settlements	9976	–		
	Unrealized gains/losses	9980	+		
	Unusual items	9985	–	1,148,177	
	Current income taxes	9990	–	263,594	
	Future (deferred) income tax provision	9995	–	875,508	23,920
	Total – Other comprehensive income	9998	+	23,312	26,347
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	3,127,168	2,615,977

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Canada Revenue Agency / Agence du revenu du Canada

Schedule 141

Notes Checklist

Corporation's name	Business number	Tax year-end Year Month Day
Brantford Power Inc.	86585 8773 RC0001	2015-12-31

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the **accountant**) who prepared or reported on the financial statements. If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI)* and T4012, *T2 Corporation – Income Tax Guide.*
- Complete this schedule and include it with your T2 return along with the other GIFI schedules.

Part 1 – Information on the accountant who prepared or reported on the financial statements

Does the accountant have a professional designation? . . . . . **095** 1 Yes [X] 2 No [ ]

Is the accountant connected* with the corporation? . . . . . **097** 1 Yes [ ] 2 No [X]

Note
If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you **do have** to complete Part 4, as applicable.

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant: **198**

Completed an auditor's report . . . . . 1 [X]

Completed a review engagement report . . . . . 2 [ ]

Conducted a compilation engagement . . . . . 3 [ ]

Part 3 – Reservations

If you selected option 1 or 2 under **Type of involvement with the financial statements** above, answer the following question:

Has the accountant expressed a reservation? . . . . . **099** 1 Yes [ ] 2 No [X]

Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options: **110**

Prepared the tax return (financial statements prepared by client) . . . . . 1 [X]

Prepared the tax return and the financial information contained therein (financial statements have not been prepared) . . . . . 2 [ ]

Were notes to the financial statements prepared? . . . . . **101** 1 Yes [X] 2 No [ ]

If **yes**, complete lines 104 to 107 below:

Are subsequent events mentioned in the notes? . . . . . **104** 1 Yes [ ] 2 No [X]

Is re-evaluation of asset information mentioned in the notes? . . . . . **105** 1 Yes [ ] 2 No [X]

Is contingent liability information mentioned in the notes? . . . . . **106** 1 Yes [X] 2 No [ ]

Is information regarding commitments mentioned in the notes? . . . . . **107** 1 Yes [X] 2 No [ ]

Does the corporation have investments in joint venture(s) or partnership(s)? . . . . . **108** 1 Yes [ ] 2 No [X]

Part 4 – Other information (continued)

Impairment and fair value changes

In any of the following assets, was an amount recognized in net income or other comprehensive income (OCI) as a result of an impairment loss in the tax year, a reversal of an impairment loss recognized in a previous tax year, or a change in fair value during the tax year? . . . . . 200 1 Yes [ ] 2 No [X]

If **yes**, enter the amount recognized:

		In net income Increase (decrease)		In OCI Increase (decrease)
Property, plant, and equipment	210		211	
Intangible assets	215		216	
Investment property	220			
Biological assets	225			
Financial instruments	230		231	
Other	235		236	

Financial instruments

Did the corporation derecognize any financial instrument(s) during the tax year (other than trade receivables)? . . . . . 250 1 Yes [ ] 2 No [X]

Did the corporation apply hedge accounting during the tax year? . . . . . 255 1 Yes [X] 2 No [ ]

Did the corporation discontinue hedge accounting during the tax year? . . . . . 260 1 Yes [ ] 2 No [X]

Adjustments to opening equity

Was an amount included in the opening balance of retained earnings or equity, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current tax year? . . . . . 265 1 Yes [X] 2 No [ ]

If **yes**, you have to maintain a separate reconciliation.

T2 BAR CODE RETURN

Name: Brantford Power Inc.

BN: 86585 8773 RC 0001

Tax Year Start: 2015-01-01

Tax Year End: 2015-12-31

attached.

SCHEDULE 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 100

Name of corporation	Business Number	Tax year-end Year Month Day
Brantford Power Inc.	86585 8773 RC0001	2015-12-31

Assets – lines 1000 to 2599

1000	12,891,079	1060	10,092,566	1066	99,504
1120	1,130,595	1125	12,149,878	1484	331,631
1599	36,695,253	1600	181,960	1900	70,864,119
1901	-5,990,842	2008	71,046,079	2009	-5,990,842
2010	1,165,571	2011	-325,552	2178	1,165,571
2179	-325,552	2420	6,897,781	2589	6,897,781
2599	109,488,290				

Liabilities – lines 2600 to 3499

2620	14,875,483	2622	449,725	2860	59,351
2862	1,419,904	2920	1,141,430	2961	1,606,069
3139	19,551,962	3140	40,919,717	3220	837,901
3240	459,557	3320	5,922,149	3450	48,139,324
3499	67,691,286				

Shareholder equity – lines 3500 to 3640

3500	22,437,505	3580	719,904	3600	18,639,595
3620	41,797,004	3640	109,488,290		

Retained earnings – lines 3660 to 3849

3660	16,724,891	3680	3,103,856	3700	-1,000,000
3740	-189,152	3849	18,639,595		

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

SCHEDULE 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 125

Name of corporation	Business Number	Tax year-end Year Month Day
Brantford Power Inc.	86585 8773 RC0001	2015-12-31

Description

Sequence number 0003 01

Other comprehensive income – lines 7000 to 7020

7008	31,717	7010	8,405

Revenue – lines 8000 to 8299

8000	21,222,171	8089	21,222,171	8100	352,260
8230	768,268	8239	410,230	8299	22,752,929

Cost of sales – lines 8300 to 8519

8519	21,222,171

Operating expenses – lines 8520 to 9369

8670	3,171,722	8714	2,245,461	8715	34,528
8960	3,252,215	9270	5,270,689	9284	3,387,179
9367	17,361,794	9368	17,361,794	9369	5,391,135

Extraordinary items and taxes – lines 9970 to 9999

9970	5,391,135	9985	1,148,177	9990	263,594
9995	875,508	9998	23,312	9999	3,127,168

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Canada Revenue Agency / Agence du revenu du Canada

Net Income (Loss) for Income Tax Purposes

Schedule 1

Corporation's name	Business Number	Tax year end Year Month Day
Brantford Power Inc.	86585 8773 RC0001	2015-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- All legislative references are to the *Income Tax Act*.

Amount calculated on line 9999 from Schedule 125			3,127,168	A
Add:				
Provision for income taxes – current	101	263,594		
Provision for income taxes – deferred	102	875,508		
Amortization of tangible assets	104	3,171,722		
Loss on disposal of assets	111	70,245		
Non-deductible meals and entertainment expenses	121	7,696		
Other reserves on lines 270 and 275 from Schedule 13	125	1,455,091		
Reserves from financial statements – balance at the end of the year	126	4,028,110		
Subtotal of additions		9,871,966 ▶	9,871,966	
Other additions:				
Miscellaneous other additions:				
600 CY cumulative adjusted regulatory asset	290	1,606,408		
601 Change in EFB's re IFRS not in P&L	291	926,001		
604				
Total	294			
Subtotal of other additions	199	2,532,409 ▶	2,532,409	
Total (lines 101 to 199)	500	12,404,375 ▶	12,404,375	B
Amount A **plus** amount B			15,531,543	C
Deduct:				
Capital cost allowance from Schedule 8	403	3,938,253		
Cumulative eligible capital deduction from Schedule 10	405	60,727		
Other reserves on line 280 from Schedule 13	413	1,606,069		
Reserves from financial statements – balance at the beginning of the year	414	4,544,466		
Subtotal of deductions		10,149,515 ▶	10,149,515	
Other deductions:				
Non-taxable/deductible other comprehensive income items	347	23,312		
Miscellaneous other deductions:				
700 Change in Sick Leave re IFRS not in P&L	390	16,380		
701 PY cumulative adjusted regulatory assets	391	1,080,944		
702 tax recovery included in net movement in regulatory balances	392	894,460		
703 Amortization of deferred revenue 14,241				
Total 14,241	393	14,241		
704 prepaid expense written off for IFRS 78,472				
Total 78,472	394	78,472		
Subtotal of other deductions	499	2,107,809 ▶	2,107,809	
Total (lines 401 to 499)	510	12,257,324 ▶	12,257,324	D
Net income (loss) for income tax purposes (amount C **minus** amount D)			3,274,219	E

Enter amount E on line 300 of the T2 return.

Attached Schedule with Total

Line 291 – Amount for line 601

Title Line 291 – Amount for line 601

Explanatory note

Balance per prior year was adjusted through RE and OCI due to IFRS conversion. The net adjustments was to change the IFRS EFB liability at December 31, 2014 to $1,205,061. The old CGAAP number was $2,099,345. The entire change was booked through RE or OCI in 2014's restated FS. As such, the impact of this needs to be factored into Schedule 1, since otherwise the change in EFB will be considered to have gone through the current year's P&L. There is also a secondary adjustment below for the change that occurred in 2015. The 2015 revised opening balance was $1,205,061 and it changed to $1,236,004. Of this change, 31,717 was booked to other comprehensive income and as such is adjusted below.

Description	Amount	
IFRS impact of change in EFB	894,284	00
2015 change in EFB booked to OCI	31,717	00
Total	926,001	00

Attached Schedule with Total

Line 390 – Amount for line 700

Title Line 390 – Amount for line 700

Explanatory note

The vested sick leave liability was $90,030 under CGAAP at December 31, 2014. It was then adjusted to 106,410 under IFRS at December 31, 2014. This change of $16,380 needs to be factored into the current year Schedule 1. In 2015 S13 shows a net change of $111,037 - 90,030 = 21,007 addback on the FS. However, $16,380 of this is not part of the current year P&L so this should be adjusted.

Description	Amount
sick Leave adj re IFRS	16,380 00
Total	16,380 00

Canada Revenue Agency / Agence du revenu du Canada

Schedule 2

Charitable Donations and Gifts

Corporation's name	Business number	Tax year-end Year Month Day
Brantford Power Inc.	86585 8773 RC0001	2015-12-31

- For use by corporations to claim any of the following:
  - the eligible amount of charitable donations to qualified donees;
  - the Ontario community food program donation tax credit for farmers;
  - the eligible amount of gifts to Canada, a province, or a territory;
  - the eligible amount of gifts of certified cultural property;
  - the eligible amount of gifts of certified ecologically sensitive land; or
  - the additional deduction for gifts of medicine.
- All legislative references are to the federal *Income Tax Act*, unless otherwise specified.
- The eligible amount of a gift is the amount by which the fair market value of the gifted property exceeds the amount of an advantage, if any, for the gift.
- The donations and gifts are eligible for a 5-year carryforward except for gifts of certified ecologically sensitive land made after February 10, 2014, which are eligible for a 10-year carryforward.
- Use this schedule to show a transfer of unused amounts from previous years following an amalgamation or the wind-up of a subsidiary as described under subsections 87(1) and 88(1) of the federal *Act*.
- Subsection 110.1(1.2) of the federal Act provides as follows:
  - Where a particular corporation has undergone an acquisition of control, for tax years that end on or after the acquisition of control, no corporation can claim a deduction for a gift made by the particular corporation to a qualified donee before the acquisition of control.
  - If a particular corporation makes a gift to a qualified donee pursuant to an arrangement under which both the gift and the acquisition of control is expected, no corporation can claim a deduction for the gift unless the person acquiring control of the particular corporation is the qualified donee.
- An eligible medical gift to a qualifying organization for activities outside of Canada may be eligible for an additional deduction. Calculate the additional deduction in Part 6.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- For more information, see the *T2 Corporation - Income Tax Guide*.

Part 1 – Charitable donations

Charity/Recipient	Amount ($100 or more only)
Subtotal	
Add: Total donations of less than $100 each	
Total donations in current tax year	

Part 1 – Charitable donations

	Line	Federal		Québec	Alberta
Charitable donations at the end of the previous tax year		2,600	A	2,600	2,600
Deduct: Charitable donations expired after five tax years*	239				
Charitable donations at the beginning of the current tax year	240	2,600	B	2,600	2,600
Add:					
Charitable donations transferred on an amalgamation or the wind-up of a subsidiary	250				
Total charitable donations made in the current year (include this amount on line 112 of Schedule 1)	210				
Subtotal (line 250 **plus** line 210)			C		
Subtotal (amount B **plus** amount C)		2,600	D	2,600	2,600
Deduct: Adjustment for an acquisition of control	255				
Total charitable donations available (amount D **minus** amount on line 255)		2,600	E	2,600	2,600
Deduct: Amount applied in the current year against taxable income (cannot be more than amount O in Part 2) (enter this amount on line 311 of the T2 return)	260	2,600		2,600	2,600
Charitable donations closing balance (amount E **minus** amount on line 260)	280				
Ontario community food program donation for farmers included in the amount on line 260 (for donations made after December 31, 2013)	262				
Ontario community food program donation tax credit for farmers (amount on line 262 **multiplied** by 25 %)			1		

Enter the amount from line 1 on line 420 of Schedule 5, *Tax Calculation Supplementary – Corporations*. The maximum amount you can claim in the current year is whichever is less; the Ontario income tax otherwise payable or the amount on line 1. For more information, see section 103.1.2 of the *Taxation Act, 2007* (Ontario).

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Amounts carried forward – Charitable donations

Year of origin:		Federal	Québec	Alberta
1st prior year	2014-12-31			
2nd prior year	2013-12-31	2,600	2,600	2,600
3rd prior year	2012-12-31			
4th prior year	2011-12-31			
5th prior year	2010-12-31			
6th prior year*	2009-12-31			
7th prior year	2008-12-31			
8th prior year	2007-12-31			
9th prior year	2006-12-31			
10th prior year	2005-12-31			
11th prior year	2004-12-31			
12th prior year	2003-12-31			
13th prior year	2002-12-31			
14th prior year	2001-12-31			
15th prior year	2000-12-31			
16th prior year				
17th prior year				
18th prior year				
19th prior year				
20th prior year				
21st prior year*				
Total (to line A)		2,600	2,600	2,600

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

Part 2 – Maximum allowable deduction for charitable donations

Net income for tax purposes* **multiplied** by 75 %			2,455,664	F
Taxable capital gains arising in respect of gifts of capital property included in Part 1 **	225	G		
Taxable capital gain in respect of a disposition of a non-qualifying security under subsection 40(1.01)	227	H		
The amount of the recapture of capital cost allowance in respect of charitable donations	230			
Proceeds of disposition, **less** outlays and expenses**		I		
Capital cost**		J		
Amount I or J, whichever is less	235			
Amount on line 230 or 235, whichever is less		K		
Subtotal (**add** amounts G, H, and K)		L		
Amount L **multiplied** by 25 %				M
Subtotal (amount F **plus** amount M)			2,455,664	N
Maximum allowable deduction for charitable donations (enter amount E from Part 1, amount N, or net income for tax purposes, whichever is less)			2,600	O

* For credit unions, subsection 137(2) states that this amount is before the deduction of payments pursuant to allocations in proportion to borrowing and bonus interest.

** This amount must be prorated by the following calculation: eligible amount of the gift **divided by** the proceeds of disposition of the gift.

Part 3 – Gifts to Canada, a province, or a territory

Gifts to Canada, a province, or a territory at the end of the previous tax year				A
Deduct: Gifts to Canada, a province, or a territory expired after five tax years		339		
Gifts to Canada, a province, or a territory at the beginning of the current tax year		340		B
Add:				
Gifts to Canada, a province, or a territory transferred on an amalgamation or the wind-up of a subsidiary	350			
Total gifts made to Canada, a province, or a territory in the current year*	310			
Subtotal (line 350 **plus** line 310)		►		C
Subtotal (amount B **plus** amount C)				D
Deduct:				
Adjustment for an acquisition of control	355			
Amount applied in the current year against taxable income (enter this amount on line 312 of the T2 return)	360			
Subtotal (line 355 **plus** line 360)		►		E
Gifts to Canada, a province, or a territory closing balance (amount D **minus** amount E)		380		

* Not applicable for gifts made after February 18, 1997, unless a written agreement was made before this date. If no written agreement exists, enter the amount on line 210 and complete Part 2.

Part 4 – Gifts of certified cultural property

	Line	Federal		Québec	Alberta
Gifts of certified cultural property at the end of the previous tax year			F		
Deduct: Gifts of certified cultural property expired after five tax years*	439				
Gifts of certified cultural property at the beginning of the current tax year	440		G		
Add:					
Gifts of certified cultural property transferred on an amalgamation or the wind-up of a subsidiary	450				
Total gifts of certified cultural property in the current year (include this amount on line 112 of Schedule 1)	410				
Subtotal (line 450 **plus** line 410)			H		
Subtotal (amount G **plus** amount H)			I		
Deduct:					
Adjustment for an acquisition of control	455				
Amount applied in the current year against taxable income (enter this amount on line 313 of the T2 return)	460				
Subtotal (line 455 **plus** line 460)			J		
Gifts of certified cultural property closing balance (amount I **minus** amount J)	480				

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Amount carried forward – Gifts of certified cultural property

Year of origin:		Federal	Québec	Alberta
1st prior year	2014-12-31			
2nd prior year	2013-12-31			
3rd prior year	2012-12-31			
4th prior year	2011-12-31			
5th prior year	2010-12-31			
6th prior year*	2009-12-31			
7th prior year	2008-12-31			
8th prior year	2007-12-31			
9th prior year	2006-12-31			
10th prior year	2005-12-31			
11th prior year	2004-12-31			
12th prior year	2003-12-31			
13th prior year	2002-12-31			
14th prior year	2001-12-31			
15th prior year	2000-12-31			
16th prior year				
17th prior year				
18th prior year				
19th prior year				
20th prior year				
21st prior year*				
Total				

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

Part 5 – Gifts of certified ecologically sensitive land

	Line	Federal		Québec	Alberta
Gifts of certified ecologically sensitive land at the end of the previous tax year			K		
Deduct: Gifts of certified ecologically sensitive land expired after 5 tax years, or after 10 tax years for gifts made after February 10, 2014*	539				
Gifts of certified ecologically sensitive land at the beginning of the current tax year	540		L		
Add:					
Gifts of certified ecologically sensitive land transferred on an amalgamation or the wind-up of a subsidiary	550				
Total current-year gifts of certified ecologically sensitive land made before February 11, 2014 (include this amount on line 112 of Schedule 1)	510				
Total current-year gifts of certified ecologically sensitive land made after February 10, 2014 (include this amount on line 112 of Schedule 1)	520				
Subtotal (**add** lines 550, 510, and 520)			M		
Subtotal (amount L **plus** amount M)			N		
Deduct:					
Adjustment for an acquisition of control	555				
Amount applied in the current year against taxable income (enter this amount on line 314 of the T2 return)	560				
Subtotal (line 555 **plus** line 560)			O		
Gifts of certified ecologically sensitive land closing balance (amount N **minus** amount O)	580				

* For the federal and Alberta, gifts made before February 11, 2014 , expire after five tax years and gifts made after February 10, 2014, expire after ten tax years. For Québec, gifts made during a tax year that ended before March 24, 2006, expire after five tax years and gifts made during a tax year that ended after March 23, 2006 expire after twenty tax years.

Amounts carried forward – Gifts of certified ecologically sensitive land

Amount of carried forward gifts made on or after February 11, 2014, in the tax year including this date . . . .

Year of origin:		Federal	Québec	Alberta
1st prior year	2014-12-31			
2nd prior year	2013-12-31			
3rd prior year	2012-12-31			
4th prior year	2011-12-31			
5th prior year	2010-12-31			
6th prior year*	2009-12-31			
7th prior year	2008-12-31			
8th prior year	2007-12-31			
9th prior year	2006-12-31			
10th prior year	2005-12-31			
11th prior year*	2004-12-31			
12th prior year	2003-12-31			
13th prior year	2002-12-31			
14th prior year	2001-12-31			
15th prior year	2000-12-31			
16th prior year				
17th prior year				
18th prior year				
19th prior year				
20th prior year				
21st prior year*				
Total				

* For the federal and Alberta, gifts made before February 11, 2014, expire after five tax years and gifts made after February 10, 2014, expire after ten tax years. The field "Amount of carried forward gifts made on or after February 11, 2014, in the tax year including this date" is used to determine the portion of the gifts made in the tax year straddling February 11, 2014, that expires after ten tax years.
For Québec, gifts made during a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Part 6 – Additional deduction for gifts of medicine

		Federal		Québec		Alberta	
Additional deduction for gifts of medicine at the end of the previous tax year			P				
Deduct: Additional deduction for gifts of medicine expired after five tax years	639						
Additional deduction for gifts of medicine at the beginning of the current tax year	640		Q				
Add:							
Additional deduction for gifts of medicine transferred on an amalgamation or the wind-up of a subsidiary	650						
Additional deduction for gifts of medicine for the current year:							
Proceeds of disposition	602		1		1		1
Cost of gifts of medicine	601		2		2		2
Subtotal (line 1 **minus** line 2)			3		3		3
Line 3 **multiplied** by 50 %			4		4		4
Eligible amount of gifts	600		5		5		5

Federal

a ______ x (b ______ / c) = Additional deduction for gifts of medicine for the current year . . . . **610** ______

Québec

a ______ x (b ______ / c) = Additional deduction for gifts of medicine for the current year . . . . ______

Alberta

a ______ x (b ______ / c) = Additional deduction for gifts of medicine for the current year . . . . ______

where:

a is the **lesser** of line 2 and line 4

b is the eligible amount of gifts (line 600)

c is the proceeds of disposition (line 602)

		Federal		Québec	Alberta
Subtotal (line 650 **plus** line 610)			R		
Subtotal (amount Q **plus** amount R)			S		
Deduct:					
Adjustment for an acquisition of control	655				
Amount applied in the current year against taxable income (enter this amount on line 315 of the T2 return)	660				
Subtotal (line 655 **plus** line 660)			T		
Additional deduction for gifts of medicine closing balance (amount S **minus** amount T)	680				

Amounts carried forward – Additional deduction for gifts of medicine

Year of origin:		Federal	Québec	Alberta
1st prior year	2014-12-31			
2nd prior year	2013-12-31			
3rd prior year	2012-12-31			
4th prior year	2011-12-31			
5th prior year	2010-12-31			
6th prior year*	2009-12-31			
Total				

***** These donations expired in the current year.

Québec – Gifts of musical instruments

Gifts of musical instruments at the end of the previous tax year		A
Deduct: Gifts of musical instruments expired after twenty tax years		B
Gifts of musical instruments at the beginning of the tax year		C
Add:		
Gifts of musical instruments transferred on an amalgamation or the wind-up of a subsidiary		D
Total current-year gifts of musical instruments		E
Subtotal (line D **plus** line E)		F
Deduct: Adjustment for an acquisition of control		G
Total gifts of musical instruments available		H
Deduct: Amount applied against taxable income		I
Gifts of musical instruments closing balance		J

Amounts carried forward – Gifts of musical instruments

Year of origin:		Québec
1st prior year	2014-12-31	
2nd prior year	2013-12-31	
3rd prior year	2012-12-31	
4th prior year	2011-12-31	
5th prior year	2010-12-31	
6th prior year*	2009-12-31	
7th prior year	2008-12-31	
8th prior year	2007-12-31	
9th prior year	2006-12-31	
10th prior year	2005-12-31	
11th prior year	2004-12-31	
12th prior year	2003-12-31	
13th prior year	2002-12-31	
14th prior year	2001-12-31	
15th prior year	2000-12-31	
16th prior year		
17th prior year		
18th prior year		
19th prior year		
20th prior year		
21st prior year*		
Total		

* These gifts expired in the current year.

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DIVIDENDS RECEIVED, TAXABLE DIVIDENDS PAID, AND PART IV TAX CALCULATION

SCHEDULE 3

Name of corporation	Business Number	Tax year-end Year Month Day
Brantford Power Inc.	86585 8773 RC0001	2015-12-31

- This schedule is for the use of any corporation to report:
  - non-taxable dividends under section 83;
  - deductible dividends under subsection 138(6);
  - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a), (b) or (d); or
  - taxable dividends paid in the tax year that qualify for a dividend refund.
- The calculations in this schedule apply only to private or subject corporations.
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the federal *Income Tax Act.*
- A recipient corporation is connected with a payer corporation at any time in a tax year, if at that time the recipient corporation:
  - controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b); or
  - owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- Column A – Enter "X" if dividends received from a foreign source (connected corporation only).
- Column F1 – Enter the amount of dividends received reported in column 240 that are eligible.
- Column F2 – Enter the code that applies to the deductible taxable dividend.
- Column FF – Indicate if the dividends have been received before January 1, 2016, or after December 31, 2015. This information is required to determine the appropriate rate for the Part IV tax calculation.

Part 1 – Dividends received in the tax year

Do not include dividends received from foreign non-affiliates.

		Complete if payer corporation is connected			
Name of payer corporation (from which the corporation received the dividend) 200	A	B Enter 1 if payer corporation is connected 205	C Business Number of connected corporation 210	D Tax year-end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends in column F were paid YYYY/MM/DD (See note) 220	E Non-taxable dividend under section 83 230
				Total (enter on line 402 of Schedule 1)	

Note: If your corporation's tax year-end is different than that of the connected payer corporation, your corporation could have received dividends from more than one tax year of the payer corporation. If so, use a separate line to provide the information for each tax year of the payer corporation.
For more details, consult the Help.

				Complete if payer corporation is connected		
F Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (b), or (d)* 240	F1 Eligible dividends (included in column F)	F2	FF	G Total taxable dividends paid by connected payer corporation (for tax year in column D) 250	H Dividend refund of the connected payer corporation (for tax year in column D)** 260	I Part IV tax before deductions F x rate *** 270
						J

Total (enter the amount from column F on line 320 of the T2 return and amount J in Part 2)

* If taxable dividends are received, enter the amount in column 240, but if the corporation is not subject to Part IV tax (such as a public corporation other than a subject corporation as defined in subsection 186(3)), enter “0” in column 270. Life insurers are not subject to Part IV tax on subsection 138(6) dividends.

** If the connected payer corporation’s tax year ends after the corporation’s balance-due day for the tax year (two or three months, as applicable), you have to estimate the payer’s dividend refund when you calculate the corporation’s Part IV tax payable.

*** For dividends received from connected corporations: Part IV tax = $\frac{\text{Column F x Column H}}{\text{Column G}}$

Rate: The Part IV tax rate is 38 1/3% for dividends received after December 31, 2015, and 33 1/3% for dividends received before January 1, 2016.

Part 2 – Calculation of Part IV tax payable

Part IV tax before deductions (amount J in Part 1)			
Deduct:			
Part IV.I tax payable on dividends subject to Part IV tax		320	
		Subtotal	
Deduct:			
Current-year non-capital loss claimed to reduce Part IV tax	330		
Non-capital losses from previous years claimed to reduce Part IV tax	335		
Current-year farm loss claimed to reduce Part IV tax	340		
Farm losses from previous years claimed to reduce Part IV tax	345		
Total losses applied against Part IV tax		x 1 / 3 =	
Part IV tax payable (enter amount on line 712 of the T2 return)		360	

Part 3 – Taxable dividends paid in the tax year that qualify for a dividend refund

	A Name of connected recipient corporation 400	B Business Number 410	C Tax year end of connected recipient corporation in which the dividends in column D were received YYYY/MM/DD (See note) 420	D Taxable dividends paid to connected corporations 430	D1 Eligible dividends (included in column D)
1	Brantford Energy Corporation	87504 1329 RC0001	2015-12-31	1,000,000	

Note

If your corporation's tax year-end is different than that of the connected recipient corporation, your corporation could have paid dividends in more than one tax year of the recipient corporation. If so, use a separate line to provide the information for each tax year of the recipient corporation. For more details, consult the Help.

Total 1,000,000

Total taxable dividends paid in the tax year to other than connected corporations		450	
Eligible dividends (included in line 450)	450a		
Total taxable dividends paid in the tax year that qualify for a dividend refund (total of column D above **plus** line 450)		460	1,000,000

Part 4 – Total dividends paid in the tax year

Complete this part if the total taxable dividends paid in the tax year that qualify for a dividend refund (line 460 above) is different from the total dividends paid in the tax year.

Total taxable dividends paid in the tax year for the purposes of a dividend refund (from above)			1,000,000
Other dividends paid in the tax year (total of 510 to 540)			
Total dividends paid in the tax year		500	1,000,000
Deduct:			
Dividends paid out of capital dividend account	510		
Capital gains dividends	520		
Dividends paid on shares described in subsection 129(1.2)	530		
Taxable dividends paid to a controlling corporation that was bankrupt at any time in the year	540		
Subtotal		▶	
Total taxable dividends paid in the tax year that qualify for a dividend refund			1,000,000

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Schedule 4

Corporation Loss Continuity and Application

Corporation's name	Business number	Tax year-end Year Month Day
Brantford Power Inc.	86585 8773 RC0001	2015-12-31

- Use this form to determine the continuity and use of available losses; to determine a current-year non-capital loss, farm loss, restricted farm loss, or limited partnership loss; to determine the amount of restricted farm loss and limited partnership loss that can be applied in a year; and to ask for a loss carryback to previous years.
- A corporation can choose whether or not to deduct an available loss from income in a tax year. The corporation can deduct losses in any order. However, for each type of loss, deduct the oldest loss first.
- According to subsection 111(4) of the *Income Tax Act*, when control has been acquired, no amount of capital loss incurred for a tax year ending before that time is deductible in computing taxable income in a tax year ending after that time. Also, no amount of capital loss incurred in a tax year ending after that time is deductible in computing taxable income of a tax year ending before that time.
- When control has been acquired, subsection 111(5) provides for similar treatment of non-capital and farm losses, except as listed in paragraphs 111(5)(a) and (b).
- For information on these losses, see the *T2 Corporation – Income Tax Guide.*
- File one completed copy of this schedule with the T2 return, or send the schedule by itself to the tax centre where the return is filed.
- All legislative references are to the *Income Tax Act*.

Part 1 – Non-capital losses

Determination of current-year non-capital loss

Net income (loss) for income tax purposes				3,274,219	A
Deduct: (increase a loss)					
Net capital losses deducted in the year (enter as a positive amount)			a		
Taxable dividends deductible under section 112 or subsections 113(1) or 138(6)			b		
Amount of Part VI.1 tax deductible under paragraph 110(1)(k)			c		
Amount deductible as prospector's and grubstaker's shares – Paragraph 110(1)(d.2)			d		
Subtotal (total of amounts a to d)			▶		B
Subtotal (amount A **minus** amount B; if positive, enter "0")					C
Deduct: (increase a loss)					
Section 110.5 or subparagraph 115(1)(a)(vii) – Addition for foreign tax deductions					D
Subtotal (amount C **minus** amount D)					E
Add: (decrease a loss)					
Current-year farm loss (the lesser of: the net loss from farming or fishing included in income and the non-capital loss before deducting the farm loss)					F
Current-year non-capital loss (amount E **plus** amount F; if positive, enter "0")					G

If amount G is negative, enter it on line 110 as a positive.

Continuity of non-capital losses and request for a carryback

Non-capital loss at the end of the previous tax year		3,430,783	e		
Deduct: Non-capital loss expired (note 1)	100		f		
Non-capital losses at the beginning of the tax year (amount e **minus** amount f)	102	3,430,783	▶	3,430,783	H
Add:					
Non-capital losses transferred on an amalgamation or on the wind-up of a subsidiary (note 2) corporation	105		g		
Current-year non-capital loss (from amount G)	110		h		
Subtotal (amount g **plus** amount h)			▶		I
Subtotal (amount H **plus** amount I)				3,430,783	J

Note 1: A non-capital loss expires as follows:
- after **10** tax years if it arose in a tax year ending after March 22, 2004, and before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

An allowable business investment loss becomes a net capital loss after **10** tax years if it arose in a tax year ending after March 22, 2004.

Note 2: Subsidiary is defined in subsection 88(1) as a taxable Canadian corporation of which 90% or more of each class of issued shares are owned by its parent corporation and the remaining shares are owned by persons that deal at arm's length with the parent corporation.

Part 1 – Non-capital losses (continued)

Deduct:

Other adjustments (includes adjustments for an acquisition of control)	150		i
Section 80 – Adjustments for forgiven amounts	140		j
Subsection 111(10) – Adjustments for fuel tax rebate			j.1
Non-capital losses of previous tax years applied in the current tax year Enter amount k on line 331 of the T2 Return.	130	3,271,619	k
Current and previous year non-capital losses applied against current-year taxable dividends subject to Part IV tax (note 3)	135		l
Subtotal (total of amounts i to l)		3,271,619 ▶	3,271,619 K
Non-capital losses before any request for a carryback (amount J **minus** amount K)			159,164 L

Deduct – **Request to carry back non-capital loss to:**

First previous tax year to reduce taxable income	901		m
Second previous tax year to reduce taxable income	902		n
Third previous tax year to reduce taxable income	903		o
First previous tax year to reduce taxable dividends subject to Part IV tax	911		p
Second previous tax year to reduce taxable dividends subject to Part IV tax	912		q
Third previous tax year to reduce taxable dividends subject to Part IV tax	913		r
Total of requests to carry back non-capital losses to previous tax years (total of amounts m to r)		▶	M
Closing balance of non-capital losses to be carried forward to future tax years (amount L **minus** amount M)	180		159,164 N

Note 3: Amount l is the total of lines 330 and 335 from Schedule 3, *Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculation*.

Part 2 – Capital losses

Continuity of capital losses and request for a carryback

Capital losses at the end of the previous tax year	200		a
Capital losses transferred on an amalgamation or on the wind-up of a subsidiary corporation	205		b
Subtotal (amount a **plus** amount b)		▶	A

Deduct:

Other adjustments (includes adjustments for an acquisition of control)	250		c
Section 80 – Adjustments for forgiven amounts	240		d
Subtotal (amount c **plus** amount d)		▶	B
Subtotal (amount A **minus** amount B)			C
Add: Current-year capital loss (from the calculation on Schedule 6, *Summary of Dispositions of Capital Property*)	210		D
Unused non-capital losses that expired in the tax year (note 4)			e
Allowable business investment losses (ABILs) that expired as non-capital losses at the end of the previous tax year (note 5)			f
Enter amount e or f, whichever is less	215		g
ABILs expired as non-capital losses: line 215 **multiplied** by 2.000000	220		E
Subtotal (total of amounts C to E)			F

Note

If there has been an amalgamation or a wind–up of a subsidiary, do a separate calculation of the ABIL expired as non-capital loss for each predecessor or subsidiary corporation. Add all these amounts and enter the total on line 220 above.

Note 4: If the loss was incurred in a tax year ending after March 22, 2004, determine the amount of the loss from the 11th previous tax year and enter the part of that loss that was not used in previous years and the current year on line e.

Note 5: If the ABILs were incurred in a tax year ending after March 22, 2004, enter the amount of the ABILs from the 11th previous tax year. Enter the full amount on line f.

Part 2 – Capital losses (continued)

Deduct: Capital losses from previous tax years applied against the current-year net capital gain (note 6)			225		G
Capital losses before any request for a carryback (amount F **minus** amount G)					H

Deduct – **Request to carry back capital loss to** (note 7):

	Capital gain (100%)		Amount carried back (100%)			
First previous tax year		951		h		
Second previous tax year		952		i		
Third previous tax year		953		j		
Subtotal (total of amounts h to j)				▶		I
Closing balance of capital losses to be carried forward to future tax years (amount H **minus** amount I)					280	J

Note 6: To get the net capital losses required to reduce the taxable capital gain included in the net income (loss) for the current-year tax, enter the amount from line 225 **divided** by 2 at line 332 of the T2 return.

Note 7: On line 225, 951, 952, or 953, whichever applies, enter the actual amount of the loss. When the loss is applied, divide this amount by 2. The result represents the 50% inclusion rate.

Part 3 – Farm losses

Continuity of farm losses and request for a carryback

Farm losses at the end of the previous tax year			a		
Deduct: Farm loss expired (note 8)	300		b		
Farm losses at the beginning of the tax year (amount a **minus** amount b)	302		▶		A
Add:					
Farm losses transferred on an amalgamation or on the wind–up of a subsidiary corporation	305		c		
Current-year farm loss (amount F in Part 1)	310		d		
Subtotal (amount c **plus** amount d)			▶		B
Subtotal (amount A **plus** amount B)					C
Deduct:					
Other adjustments (includes adjustments for an acquisition of control)	350		e		
Section 80 – Adjustments for forgiven amounts	340		f		
Farm losses of previous tax years applied in the current tax year Enter amount g on line 334 of the T2 Return.	330		g		
Current and previous year farm losses applied against current-year taxable dividends subject to Part IV tax (note 9)	335		h		
Subtotal (total of amounts e to h)			▶		D
Farm losses before any request for a carryback (amount C **minus** amount D)					E
Deduct – **Request to carry back farm loss to:**					
First previous tax year to reduce taxable income	921		i		
Second previous tax year to reduce taxable income	922		j		
Third previous tax year to reduce taxable income	923		k		
First previous tax year to reduce taxable dividends subject to Part IV tax	931		l		
Second previous tax year to reduce taxable dividends subject to Part IV tax	932		m		
Third previous tax year to reduce taxable dividends subject to Part IV tax	933		n		
Subtotal (total of amounts i to n)			▶		F
Closing balance of farm losses to be carried forward to future tax years (amount E **minus** amount F)				380	G

Note 8: A farm loss expires as follows:

- after **10** tax years if it arose in a tax year ending before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

Note 9: Amount h is the total of lines 340 and 345 from Schedule 3.

Part 4 – Restricted farm losses

Current-year restricted farm loss

Total losses for the year from farming business			485		A
Minus the deductible farm loss:					
(amount A above ______ – $2,500) **divided** by 2 =		a			
Amount a or $ 15,000 (note 10), whichever is less		b			
	2,500	c			
Subtotal (amount b **plus** amount c)	2,500	▶		2,500	B
Current-year restricted farm loss (amount A **minus** amount B)					C

Continuity of restricted farm losses and request for a carryback

Restricted farm losses at the end of the previous tax year			d		
Deduct: Restricted farm loss expired (note 11)	400		e		
Restricted farm losses at the beginning of the tax year (amount d **minus** amount e)	402		▶		D
Add:					
Restricted farm losses transferred on an amalgamation or on the wind-up of a subsidiary corporation	405		f		
Current-year restricted farm loss (from amount C) Enter amount g on line 233 of Schedule 1, *Net Income (Loss) for Income Tax Purposes*.	410		g		
Subtotal (amount f **plus** amount g)			▶		E
Subtotal (amount D **plus** amount E)					F
Deduct:					
Restricted farm losses from previous tax years applied against current farming income Enter amount h on line 333 of the T2 return.	430		h		
Section 80 – Adjustments for forgiven amounts	440		i		
Other adjustments	450		j		
Subtotal (total of amounts h to j)			▶		G
Restricted farm losses before any request for a carryback (amount F **minus** amount G)					H
Deduct – Request to carry back restricted farm loss to:					
First previous tax year to reduce farming income	941		k		
Second previous tax year to reduce farming income	942		l		
Third previous tax year to reduce farming income	943		m		
Subtotal (total of amounts k to m)			▶		I
Closing balance of restricted farm losses to be carried forward to future tax years (amount H **minus** amount I)	480				J

Note

The total losses for the year from all farming businesses are calculated without including scientific research expenses.

Note 10: For tax years that end before March 21, 2013, use $6,250 instead of $15,000.

Note 11: A restricted farm loss expires as follows:
- after **10** tax years if it arose in a tax year ending before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

Part 5 – Listed personal property losses

Continuity of listed personal property loss and request for a carryback

Listed personal property losses at the end of the previous tax year			a		
Deduct: Listed personal property loss expired after 7 tax years	500		b		
Listed personal property losses at the beginning of the tax year (amount a **minus** amount b)	502		▶		A
Add: Current-year listed personal property loss (from Schedule 6)			510		B
Subtotal (amount A **plus** amount B)					C
Deduct:					
Listed personal property losses from previous tax years applied against listed personal property gains	530		c		
Enter amount c on line 655 of Schedule 6.					
Other adjustments	550		d		
Subtotal (amount c **plus** amount d)			▶		D
Listed personal property losses remaining before any request for a carryback (amount C **minus** amount D)					E
Deduct – Request to carry back listed personal property loss to:					
First previous tax year to reduce listed personal property gains	961		e		
Second previous tax year to reduce listed personal property gains	962		f		
Third previous tax year to reduce listed personal property gains	963		g		
Subtotal (total of amounts e to g)			▶		F
Closing balance of listed personal property losses to be carried forward to future tax years (amount E **minus** amount F)			580		G

Part 7 – Limited partnership losses

Current-year limited partnership losses

	1	2	3	4	5	6	7
	Partnership account number **600**	Tax year ending yyyy/mm/dd **602**	Corporation's share of limited partnership loss **604**	Corporation's at-risk amount **606**	Total of corporation's share of partnership investment tax credit, farming losses, and resource expenses **608**	Column 4 **minus** column 5 (if negative, enter "0")	Current-year limited partnership losses (column 3 **minus** column 6) **620**
1.							
						Total (enter this amount on line 222 of Schedule 1)	

Limited partnership losses from previous tax years that may be applied in the current year

	1	2	3	4	5	6	7
	Partnership account number **630**	Tax year ending yyyy/mm/dd **632**	Limited partnership losses at the end of the previous tax year and amounts transferred on an amalgamation or on the wind-up of a subsidiary **634**	Corporation's at-risk amount **636**	Total of corporation's share of partnership investment tax credit, business or property losses, and resource expenses **638**	Column 4 **minus** column 5 (if negative, enter "0")	Limited partnership losses that may be applied in the year (the lesser of columns 3 and 6) **650**
1.							

Continuity of limited partnership losses that can be carried forward to future tax years

	1	2	3	4	5	6
	Partnership account number **660**	Limited partnership losses at the end of the previous tax year **662**	Limited partnership losses transferred in the year on an amalgamation or on the wind-up of a subsidiary **664**	Current-year limited partnership losses (from line 620) **670**	Limited partnership losses applied in the current year (must be equal to or less than line 650) **675**	Current year limited partnership losses closing balance to be carried forward to future years (column 2 **plus** column 3 **plus** column 4 **minus** column 5) **680**
1.						
				Total (enter this amount on line 335 of the T2 return)		

Note

If you need more space, you can attach more schedules.

Part 8 – Election under paragraph 88(1.1)(f)

If you are making an election under paragraph 88(1.1)(f), check the box . . . . **190** Yes ☐

In the case of the wind-up of a subsidiary, if the election is made, the non-capital loss, restricted farm loss, farm loss, or limited partnership loss of the subsidiary—that otherwise would become the loss of the parent corporation for a particular tax year starting after the wind–up began—will be considered as the loss of the parent corporation for its immediately preceding tax year and not for the particular year.

Note

This election is only applicable for wind-ups under subsection 88(1) that are reported on Schedule 24, *First-Time Filer after Incorporation, Amalgamation, or Winding-up of a Subsidiary into a Parent*.

Non-Capital Loss Continuity Workchart

Part 6 – Analysis of balance of losses by year of origin

Non-capital losses – losses that can be carried forward over 20 years

Year of origin	Balance at beginning of year	Loss incurred in current year	Adjustments and transfers	Loss carried back Parts I & IV	Applied to reduce Taxable income	Applied to reduce Part IV tax	Balance at end of year
Current	N/A				N/A		
1st preceding taxation year 2014-12-31	3,430,783	N/A		N/A	3,271,619		159,164
2nd preceding taxation year 2013-12-31		N/A		N/A			
3rd preceding taxation year 2012-12-31		N/A		N/A			
4th preceding taxation year 2011-12-31		N/A		N/A			
5th preceding taxation year 2010-12-31		N/A		N/A			
6th preceding taxation year 2009-12-31		N/A		N/A			
7th preceding taxation year 2008-12-31		N/A		N/A			
8th preceding taxation year 2007-12-31		N/A		N/A			
9th preceding taxation year 2006-12-31		N/A		N/A			
10th preceding taxation year 2005-12-31		N/A		N/A			
11th preceding taxation year 2004-12-31		N/A		N/A			
12th preceding taxation year 2003-12-31		N/A		N/A			
13th preceding taxation year 2002-12-31		N/A		N/A			
14th preceding taxation year 2001-12-31		N/A		N/A			
15th preceding taxation year 2000-12-31		N/A		N/A			
16th preceding taxation year		N/A		N/A			
17th preceding taxation year		N/A		N/A			
18th preceding taxation year		N/A		N/A			
19th preceding taxation year		N/A		N/A			
20th preceding taxation year		N/A		N/A			*
Total	3,430,783				3,271,619		159,164

*** This balance expires this year and will not be available next year.**

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Schedule 5

Tax Calculation Supplementary – Corporations

Corporation's name	Business Number	Tax year-end Year Month Day
Brantford Power Inc.	86585 8773 RC0001	2015-12-31

- Use this schedule if, during the tax year, the corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B and D in Part 1);
  - is claiming provincial or territorial tax credits or rebates (see Part 2); or
  - has to pay taxes, other than income tax, for Newfoundland and Labrador, or Ontario (see Part 2).
- Regulations mentioned in this schedule are from the *Income Tax Regulations.*
- For more information, see the *T2 Corporation – Income Tax Guide.*
- Enter the regulation number in field 100 of Part 1.

Part 1 – Allocation of taxable income

100 ______ Enter the Regulation that applies (402 to 413).

A Jurisdiction Tick yes if the corporation had a permanent establishment in the jurisdiction during the tax year. *		B Total salaries and wages paid in jurisdiction	C (B x taxable income) / G	D Gross revenue	E (D x taxable income) / H	F Allocation of taxable income (C + E) x 1/2** (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	003 1 Yes	103		143		
Newfoundland and Labrador Offshore	004 1 Yes	104		144		
Prince Edward Island	005 1 Yes	105		145		
Nova Scotia	007 1 Yes	107		147		
Nova Scotia Offshore	008 1 Yes	108		148		
New Brunswick	009 1 Yes	109		149		
Quebec	011 1 Yes	111		151		
Ontario	013 1 Yes	113		153		
Manitoba	015 1 Yes	115		155		
Saskatchewan	017 1 Yes	117		157		
Alberta	019 1 Yes	119		159		
British Columbia	021 1 Yes	121		161		
Yukon	023 1 Yes	123		163		
Northwest Territories	025 1 Yes	125		165		
Nunavut	026 1 Yes	126		166		
Outside Canada	027 1 Yes	127		167		
Total		129 G		169 H		

* "Permanent establishment" is defined in Regulation 400(2).
** For corporations other than those described under Regulation 402, use the appropriate calculation described in the Regulations to allocate taxable income.

Notes:
1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the *T2 Corporation – Income Tax Guide*.
2. If the corporation has provincial or territorial tax payable, complete Part 2.
3. Special rules for establishing a corporation's gross revenue and salaries and wages attributable to a jurisdiction are provided in cases where the corporation operates in a partnership and the partnership had permanent establishments in more than one jurisdiction. See Guide T4068, *Guide for the Partnership Information Return* and prescribed Form T5013 Sch 5, *Allocation of Salaries and Wages, and Gross Revenue for Multiple Jurisdictions*.

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits

	Line	Amount		Total	
Ontario basic income tax (from Schedule 500)	270				
Deduct: Ontario small business deduction (from Schedule 500)	402				
Subtotal			►		A6
Add:					
Ontario additional tax re Crown royalties (from Schedule 504)	274				
Ontario transitional tax debits (from Schedule 506)	276				
Recapture of Ontario research and development tax credit (from Schedule 508)	277				
Subtotal			►		B6
Subtotal (amount A6 **plus** amount B6)					C6
Deduct:					
Ontario resource tax credit (from Schedule 504)	404				
Ontario tax credit for manufacturing and processing (from Schedule 502)	406				
Ontario foreign tax credit (from Schedule 21)	408				
Ontario credit union tax reduction (from Schedule 500)	410				
Ontario political contributions tax credit (from Schedule 525)	415				
Subtotal			►		D6
Subtotal (amount C6 **minus** amount D6) (if negative, enter "0")					E6
Deduct: Ontario research and development tax credit (from Schedule 508)			416		
Ontario corporate income tax payable before Ontario corporate minimum tax credit and Ontario community food program donation tax credit for farmers (amount E6 **minus** amount on line 416) (if negative, enter "0")					F6
Deduct:					
Ontario corporate minimum tax credit (from Schedule 510)			418		
Ontario community food program donation tax credit for farmers (from Schedule 2)			420		
Ontario corporate income tax payable (amount F6 **minus** amounts on line 418 and line 420) (if negative, enter "0")					G6
Add:					
Ontario corporate minimum tax (from Schedule 510)	278				
Ontario special additional tax on life insurance corporations (from Schedule 512)	280				
Subtotal			►		H6
Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6)					I6
Deduct:					
Ontario qualifying environmental trust tax credit	450				
Ontario co-operative education tax credit (from Schedule 550)	452				
Ontario apprenticeship training tax credit (from Schedule 552)	454	20,000			
Ontario computer animation and special effects tax credit (from Schedule 554)	456				
Ontario film and television tax credit (from Schedule 556)	458				
Ontario production services tax credit (from Schedule 558)	460				
Ontario interactive digital media tax credit (from Schedule 560)	462				
Ontario sound recording tax credit (from Schedule 562)	464				
Ontario book publishing tax credit (from Schedule 564)	466				
Ontario innovation tax credit (from Schedule 566)	468				
Ontario business-research institute tax credit (from Schedule 568)	470				
Subtotal		20,000	►	20,000	J6
Net Ontario tax payable or refundable credit (amount I6 **minus** amount J6) (if a credit, enter a negative amount) Include this amount on line 255.			290	-20,000	K6

Summary

Enter the total net tax payable or refundable credits for all provinces and territories on line 255.

Net provincial and territorial tax payable or refundable credits . . . . **255** -20,000

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

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Schedule 8

Capital Cost Allowance (CCA)

Corporation's name	Business Number	Tax year end Year Month Day
Brantford Power Inc.	86585 8773 RC0001	2015-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under *Regulation* 1101(5q)? **101** 1 Yes [ ] 2 No [X]

	1 Class number (See Note) **200**	Description	2 Undepreciated capital cost at the beginning of the year (amount from column 12 of last year's schedule 8) **201**	3 Cost of acquisitions during the year (new property must be available for use)* **203**	4 Adjustments and transfers** **205**	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) **207**	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** **211**	7 Reduced undepreciated capital cost	8 CCA rate % **** **212**	9 Recapture of capital cost allowance***** (line 107 of Schedule 1) **213**	10 Terminal loss (line 404 of Schedule 1) **215**	11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) ****** **217**	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) **220**
1.	1		958,730			0		958,730	4	0	0	38,349	920,381
2.	8		480,769	202,461		0	101,231	581,999	20	0	0	116,400	566,830
3.	10		493,238	399,909		23,000	188,455	681,692	30	0	0	204,508	665,639
4.	1		27,792,835			0		27,792,835	4	0	0	1,111,713	26,681,122
5.	47		27,712,451	3,120,274		719,752	1,200,261	28,912,712	8	0	0	2,313,017	27,799,956
6.	50		48,829	9,465		0	4,733	53,561	55	0	0	29,459	28,835
7.	12		59,313	112,925		0	56,463	115,775	100	0	0	115,775	56,463
8.	13		17,893	12,050		0	1,205	28,738	NA	0	0	6,317	23,626
9.	13		10,858			0		10,858	NA	0	0	2,715	8,143
		Totals	57,574,916	3,857,084		742,752	1,552,348	59,136,900				3,938,253	56,750,995

Note: Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed.
Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see *Regulation* 1100(2) and (2.2).

** Enter in column 4, "Adjustments and transfers", amounts that increase or reduce the undepreciated capital cost.
Items that **increase** the undepreciated capital cost include amounts transferred under section 85, or transferred on amalgamation or winding-up of a subsidiary. Items that **reduce** the undepreciated capital cost include government assistance received or entitled to be received in the year, or a reduction of capital cost after the application of section 80. See the *T2 Corporation Income Tax Guide* for other examples of adjustments and transfers to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) **plus** or **minus** certain adjustments and transfers from column 4. For information on the exceptions to the 50% rule, as well as how to calculate the amounts to enter in column 6 in those cases, see Interpretation Bulletin IT-285, *Capital Cost Allowance - General Comments*.

**** Enter a rate only if you are using the declining balance method. For any other method (for example the straight-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 11.

***** For every entry in column 9, the "Recapture of capital cost allowance" there must be a corresponding entry in column 5, "Proceeds of dispositions during the year". The recapture and terminal loss rules do not apply to passenger vehicles in Class 10.1.

****** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

T2 SCH 8 (14)

Canada

Fixed Assets Reconciliation

Reconciliation of change in fixed assets per financial statements to amounts used per tax return.

Tax return

Additions for tax purposes – Schedule 8 regular classes		3,845,034		
Additions for tax purposes – Schedule 8 leasehold improvements	+	12,050		
Operating leases capitalized for book purposes	+			
Capital gain deferred	+			
Recapture deferred	+			
Deductible expenses capitalized for book purposes – Schedule 1	+			
Other (specify):				
Change in WIP	+	42,464		
Land rights added to S10	+	254,227		
Capital contributions received classified separate on BS	+	308,810		
Total additions per books	=	4,462,585	▶	4,462,585
Proceeds up to original cost – Schedule 8 regular classes		742,752		
Proceeds up to original cost – Schedule 8 leasehold improvements	+			
Proceeds in excess of original cost – capital gain	+			
Recapture deferred – as above	+			
Capital gain deferred – as above	+			
Pre V-day appreciation	+			
Other (specify):				
rounding	+	-1,923		
amortization of intangible assets included in total amortization	+	180,221		
stranded meter proceeds including as reduction of reg assets	+	-719,752		
deferred contributions from 2014 reclassified under IFRS	+	-439,812		
disposals of plant held for future use	+	6,500		
Total proceeds per books	=	-232,014	▶ –	-232,014
Depreciation and amortization per accounts – Schedule 1			–	3,171,722
Loss on disposal of fixed assets per accounts			–	70,245
Gain on disposal of fixed assets per accounts			+	
Net change per tax return			=	1,452,632

Financial statements

Fixed assets (excluding land) per financial statements

Closing net book value		64,873,277
Opening net book value	–	63,420,645
Net change per financial statements	=	1,452,632

If the amounts from the tax return and the financial statements differ, explain why below.

Attached Schedule with Total

Financial statements – Fixed assets (excluding land) per financial statements – Opening net book value

Title Financial statements – Fixed assets (excluding land) per financial statemen

Description	Amount	
opening NBV	63,602,605	00
less: land	-181,960	00
Total	63,420,645	00

Attached Schedule with Total

Other – Amount

Title Other – Amount

Description	Amount
	8,475 00
	245,752 00
Total	254,227 00

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SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
Brantford Power Inc.	86585 8773 RC0001	2015-12-31

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

	Name 100	Country of residence (other than Canada) 200	Business number (see note 1) 300	Relationship code (see note 2) 400	Number of common shares you own 500	% of common shares you own 550	Number of preferred shares you own 600	% of preferred shares you own 650	Book value of capital stock 700
1.	Brantford Energy Corporation		87504 1329 RC0001	1					
2.	Brantford Generation Inc		83941 2814 RC0001	3					
3.	Brantford Hydro Inc.		87504 1121 RC0001	3					
4.	The Corporation of the City of Brant		12268 6793 RC0001	3					

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.
Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

T2 SCH 9 (11) Canada

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SCHEDULE 10

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year-end Year Month Day
Brantford Power Inc.	86585 8773 RC0001	2015-12-31

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide*.
- A separate cumulative eligible capital account must be kept for each business.

Part 1 – Calculation of current year deduction and carry-forward

	Line	Amount		Line	Amount	
Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter "0")				200	676,857	A
Add: Cost of eligible capital property acquired during the taxation year	222	254,227				
Other adjustments	226					
Subtotal (line 222 plus line 226)		254,227	x 3 / 4 = 190,670 B			
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002	228		x 1 / 2 = C			
amount B minus amount C (if negative, enter "0")			190,670 ▶		190,670	D
Amount transferred on amalgamation or wind-up of subsidiary				224		E
Subtotal (add amounts A, D, and E)				230	867,527	F
Deduct: Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year	242		G			
The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7)	244		H			
Other adjustments	246		I			
(add amounts G,H, and I)			x 3 / 4 =	248		J
Cumulative eligible capital balance (amount F minus amount J)					867,527	K
(if amount K is negative, enter "0" at line M and proceed to Part 2)						
Cumulative eligible capital for a property no longer owned after ceasing to carry on that business			249			
amount K		867,527				
less amount from line 249						
Current year deduction		867,527	x 7.00 % = 250	60,727 *		
(line 249 plus line 250) (enter this amount at line 405 of Schedule 1)			60,727 ▶		60,727	L
Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0")				300	806,800	M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

Amount from line K (show as positive amount)						N
Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988			400		1	
Total of all amounts which reduced CEC in the current or prior years under subsection 80(7)			401		2	
Total of CEC deductions claimed for taxation years beginning before July 1, 1988	402		3			
Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988	408		4			
Line 3 minus line 4 (if negative, enter "0")			►		5	
Total of lines 1, 2 and 5					6	
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400			7			
Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000			8			
Subtotal (line 7 plus line 8)	409		►		9	
Line 6 minus line 9 (if negative, enter "0")					►	O
Line N minus line O (if negative, enter "0")						P
			Line 5	x 1 / 2 =		Q
Line P minus line Q (if negative, enter "0")						R
			Amount R	x 2 / 3 =		S
Amount N or amount O, whichever is less						T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)				410		

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SCHEDULE 13

CONTINUITY OF RESERVES

Name of corporation	Business number	Tax year end Year Month Day
Brantford Power Inc.	86585 8773 RC0001	2015-12-31

- For use by corporations to provide a continuity of all reserves claimed which are allowed for tax purposes.
- File one completed copy of this schedule with the corporation's *T2 Corporation Income Tax Return*.
- For more information, see the *T2 Corporation Income Tax Guide*.

Part 1 – Capital gains reserves

	Description of property 001	Balance at the beginning of the year $ 002	Transfer on an amalgamation or the wind-up of a subsidiary $ 003	Add $	Deduct $	Balance at the end of the year $ 004
1						
	Totals	008	009			010

The amount from line 008 **plus** the amount from line 009 should be entered on line 880 of Schedule 6, *Summary of Dispositions of Capital Property*. The amount from line 010 should be entered on line 885 of Schedule 6.

Part 2 – Other reserves

Description		Balance at the beginning of the year $	Transfer on an amalgamation or the wind-up of a subsidiary $	Add $	Deduct $	Balance at the end of the year $
Reserve for doubtful debts	☐	110	115			120
Reserve for undelivered goods and services not rendered	X	130 1,455,091	135	1,606,069	1,455,091	140 1,606,069
Reserve for prepaid rent	☐	150	155			160
Reserve for refundable containers . .	☐	190	195			200
Reserve for unpaid amounts	☐	210	215			220
Other tax reserves	☐	230	235			240
Totals		270 1,455,091	275	1,606,069	1,455,091	280 1,606,069

Enter "X" in the column above if the tax reserve has also been reported on the corporation's financial statements. This allows offsetting entries on Schedule 1, resulting in a zero effect on net income for tax purposes.

The amount from line 270 **plus** the amount from line 275 should be entered on line 125 of Schedule 1, *Net Income (Loss) for Income Tax Purposes*, as an addition. The amount from line 280 should be entered on line 413 of Schedule 1 as a deduction.

Continuity of financial statement reserves (not deductible)

Financial statement reserves (not deductible)

	Description	Balance at the beginning of the year	Transfer on an amalgamation or the wind-up of a subsidiary	Add	Deduct	Balance at the end of the year
1	Employee Future Benefits	2,099,345		1,236,004	2,099,345	1,236,004
2	Allowance for Doubtful Account	900,000		750,000	900,000	750,000
3	Vested Sick Leave	90,030		111,037	90,030	111,037
4	General accrual			325,000		325,000
5						
	Reserves from Part 2 of Schedule 13	1,455,091		1,606,069	1,455,091	1,606,069
	Totals	4,544,466		4,028,110	4,544,466	4,028,110

The total opening balance plus the total transfers should be entered on line 414 of Schedule 1 as a deduction.
The total closing balance should be entered on line 126 of Schedule 1 as an addition.

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SCHEDULE 14

MISCELLANEOUS PAYMENTS TO RESIDENTS

Name of corporation	Business Number	Tax year end Year Month Day
Brantford Power Inc.	86585 8773 RC0001	2015-12-31

- This schedule must be completed by all corporations who made the following payments to residents of Canada: royalties for which the corporation has not filed a T5 slip; research and development fees; management fees; technical assistance fees; and similar payments.
- Please enter the name and address of the recipient and the amount of the payment in the applicable column. If several payments of the same type (i.e., management fees) were made to the same person, enter the total amount paid. If similar types of payments have been made, but do not fit into any of the categories, enter these amounts in the column entitled "Similar payments".

	Name of recipient 100	Address of recipient 200	Royalties 300	Research and development fees 400	Management fees 500	Technical assistance fees 600	Similar payments 700
1	Brantford Energy Corp	84 Market Square PO Box 308 Brantford ON CA N3T 5N8			160,728		

T2 SCH 14 (99)

Canada

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Schedule 15

Deferred Income Plans

Corporation's name	Business number	Tax year end Year Month Day
Brantford Power Inc.	86585 8773 RC0001	2015-12-31

- Complete the information below if the corporation deducted payments from its income made to a registered pension plan (RPP), a registered supplementary unemployment benefit plan (RSUBP), a deferred profit sharing plan (DPSP), a pooled registered pension plan (PRPP), or an employee profit sharing plan (EPSP).
- If the trust that governs an employee profit sharing plan is **not resident** in Canada, please indicate if the T4PS, *Statement of Employees Profit Sharing Plan Allocations and Payments*, Supplementary slip(s) were filed for the last calendar year, and whether they were filed by the trustee or the employer.

	Type of plan (see note 1) 100	Amount of contribution $ (see note 2) 200	Registration number (RPP, RSUBP, PRPP, and DPSP only) 300	Name of EPSP trust 400	Address of EPSP trust 500	T4PS slip(s) (see note 3) 600
1	1	467,702	0345983			

Note 1

Enter the applicable code number:

1 – RPP
2 – RSUBP
3 – DPSP
4 – EPSP
5 – PRPP

Note 2

You do not need to add to Schedule 1 any payments you made to deferred income plans.
To reconcile such payments, calculate the following amount:

Total of all amounts indicated in column 200 of this schedule . . . . 467,702 A

Less:

Total of all amounts for deferred income plans deducted in your financial statements . . . . . 467,702 B

Deductible amount for contributions to deferred income plans
(amount A **minus** amount B) (if negative, enter "0") C

Enter amount C on line 417 of Schedule 1

Note 3

T4PS slip(s) filed by: 1 – Trustee
2 – Employer (EPSP only)

T2 SCH 15 (13)

Canada

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Schedule 23

Agreement Among Associated Canadian-Controlled Private Corporations to Allocate the Business Limit

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group. Include non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* not to be associated for purposes of the small business deduction.

Column 2: Provide the business number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code from the list below that applies to each corporation:

1 – Associated for purposes of allocating the business limit (unless code 5 applies)
2 – CCPC that is a "third corporation" that has elected under subsection 256(2) not to be associated for purposes of the small business deduction
3 – Non-CCPC that is a "third corporation" as defined in subsection 256(2)
4 – Associated non-CCPC
5 – Associated CCPC to which code 1 does not apply because of a subsection 256(2) election made by a "third corporation"

Column 4: Enter the business limit for the year of each corporation in the associated group.

Column 5: Assign a percentage to allocate the business limit to each corporation that has an association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A.

Ensure that the total at line A does not exceed $500,000.

Allocating the business limit

Date filed (do not use this area) . . . . . **025** Year Month Day

Enter the calendar year to which the agreement applies . . . . . **050** Year 2015

Is this an amended agreement for the above calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . . **075** 1 Yes [ ] 2 No [X]

	1 Names of associated corporations **100**	2 Business number of associated corporations **200**	3 Association code **300**	4 Business limit for the year before the allocation $	5 Percentage of the business limit % **350**	6 Business limit allocated* $ **400**
1	Brantford Power Inc.	86585 8773 RC0001	1	500,000		
2	Brantford Energy Corporation	87504 1329 RC0001	1	500,000		
3	Brantford Generation Inc	83941 2814 RC0001	1	500,000		
4	Brantford Hydro Inc.	87504 1121 RC0001	1	500,000	100.0000	500,000
5	The Corporation of the City of Brantford	12268 6793 RC0001	4			
				Total	100.0000	500,000 A

Business limit reduction under subsection 125(5.1) of the Act

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "large corporation amount" at line 415 of the T2 return. The amount at line 415 is determined using the formula 0.225% x (D - $10,000,000). Details of this formula and variable D are in subsection 125(5.1) of the Act.

* Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules for business limit

Special rules apply under subsection 125(5) if a CCPC has more than one tax year ending in the same calendar year and it is associated in more than one of those tax years with another CCPC that has a tax year ending in that calendar year. The business limit for the second or later tax year will be equal to the business limit determined for the first tax year ending in the calendar year or the business limit determined for the second or later tax year ending in the same calendar year, whichever is less.

Canada Revenue Agency / Agence du revenu du Canada

Schedule 31

Investment Tax Credit – Corporations

General information

- Use this schedule:
  - to calculate an investment tax credit (ITC) earned during the tax year;
  - to claim a deduction against Part I tax payable;
  - to claim a refund of credit earned during the current tax year;
  - to claim a carryforward of credit from previous tax years;
  - to transfer a credit following an amalgamation or wind-up of a subsidiary, as described under subsections 87(1) and 88(1) of the *Income Tax Act*;
  - to request a credit carryback to one or more previous years; or
  - if you are subject to a recapture of ITC.
- The ITC is eligible for a three-year carryback (if not deductible in the year earned). It is also eligible for a twenty-year carryforward.
- All legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- Investments or expenditures, described in subsection 127(9) of the Act and Part XLVI of the Regulations, that earn an ITC are:
  - qualified property and qualified resource property (Parts 4 to 7 of this schedule);
  - expenditures that are part of the SR&ED qualified expenditure pool (Parts 8 to 17). File Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim;*
  - pre-production mining expenditures (Parts 18 to 20);
  - apprenticeship job creation expenditures (Parts 21 to 23); and
  - child care spaces expenditures (Parts 24 to 28).
- Include a completed copy of this schedule with the *T2 Corporation Income Tax Return*. If you need more space, attach additional schedules.
- For more information on ITCs, see "Investment Tax Credit" in Guide T4012, *T2 Corporation – Income Tax Guide*, Information Circular IC78-4, *Investment Tax Credit Rates*, and its related Special Release.
- For more information on SR&ED, see T4088, *Guide to Form T661 – Scientific Research and Experimental Development (SR&ED) Expenditures Claim*. Also see the *Eligibility of Work for SR&ED Investment Tax Credits Policy* at **www.cra.gc.ca/txcrdt/sred-rsde/clmng/lgbltywrkfrsrdnvstmnttxcrdts-eng.html**.

Detailed information

- For the purpose of this schedule, **investment** means the capital cost of the property (excluding amounts added by an election under section 21), determined without reference to subsections 13(7.1) and 13(7.4), minus the amount of any government or non-government assistance that the corporation has received, is entitled to receive, or can reasonably be expected to receive for that property when it files the income tax return for the year in which the property was acquired.
- An ITC deducted or refunded in a tax year for a depreciable property, other than a depreciable property deductible under paragraph 37(1)(b), reduces the capital cost of that property in the next tax year. It also reduces the undepreciated capital cost of that class in the next tax year. An ITC for SR&ED deducted or refunded in a tax year will reduce the balance in the pool of deductible SR&ED expenditures and the adjusted cost base (ACB) of an interest in a partnership in the next tax year. An ITC from pre-production mining expenditures deducted in a tax year reduces the balance in the pool of deductible cumulative Canadian exploration expenses in the next tax year.
- Property acquired has to be **available for use** before a claim for an ITC can be made. See subsections 127(11.2) and 248(19) for more information.
- Expenditures for SR&ED and capital costs for a property qualifying for an ITC must be identified by the claimant on Form T661 and Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which it incurred the expenditures or capital costs.
- Expenditures for pre-production mining, apprenticeship, or child care space for an ITC must be identified by the claimant on Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which it incurred the expenditures or capital costs.
- Partnership allocations – Subsection 127(8) provides for the allocation of the amount that may reasonably be considered to be a partner's share of the ITCs of the partnership at the end of the fiscal period of the partnership. An allocation of ITCs is generally considered to be the partner's reasonable share of the ITCs if it is made in the same proportion in which the partners have agreed to share any income or loss and if section 103 is not applicable for the agreement to share any income or loss. Special rules apply to specified and limited partners. For more information, see Guide T4068, *Guide for the Partnership Information Return*.
- For SR&ED expenditures, the expression **in Canada** includes the "exclusive economic zone" (as defined in the *Oceans Act* to generally consist of an area that is within 200 nautical miles from the Canadian coastline), including the airspace, seabed and subsoil for that zone.
- For the purpose of this schedule, the expression **Atlantic Canada** includes the Gaspé Peninsula and the provinces of Newfoundland and Labrador, Prince Edward Island, Nova Scotia, and New Brunswick, as well as their respective offshore regions (prescribed in Regulation 4609).
- For the purpose of this schedule, **qualified property** means property in Atlantic Canada that is used primarily for manufacturing and processing, farming or fishing, logging, storing grain, or harvesting peat. Property in Atlantic Canada that is used primarily for oil and gas, and mining activities is considered qualified property only if acquired by the taxpayer **before** March 29, 2012. Qualified property includes new buildings and new machinery and equipment (prescribed in Regulation 4600), and if acquired by the taxpayer **after** March 28, 2012, new energy generation and conservation property (prescribed in Regulation 4600). Qualified property can also be used primarily to produce or process electrical energy or steam in a prescribed area (as described in Regulation 4610). See the definition of **qualified property** in subsection 127(9) for more information.

Detailed information (continued)

- For the purpose of this schedule, **qualified resource property** means property in Atlantic Canada that is used primarily for oil and gas, and mining activities, if acquired by the taxpayer **after** March 28, 2012, and **before** January 1, 2016. Qualified resource property includes new buildings and new machinery and equipment (prescribed in Regulation 4600). See the definition of **qualified resource property** in subsection 127(9) for more information.
- For the purpose of this schedule, **pre-production mining exploration expenditures** are pre-production mining expenditures incurred **after** March 28, 2012, by the taxpayer to determine the existence, location, extent, or quality of certain mineral resources in Canada, excluding expenses incurred in the exploration of an oil or gas well. See subparagraph (a)(i) of the definition of **pre-production mining expenditure** in subsection 127(9) for more information.
- For the purpose of this schedule, **pre-production mining development expenditures** are pre-production mining expenditures incurred **after** March 28, 2012, by the taxpayer to bring a new mineral resource mine in Canada into production, excluding expenses in the development of a bituminous sands deposit or an oil shale deposit. See subparagraph (a)(ii) of the definition of **pre-production mining expenditure** in subsection 127(9) for more information.

Part 1 – Investments, expenditures, and percentages

	Specified percentage
Investments	
Qualified property acquired primarily for use in Atlantic Canada	10 %
Qualified resource property acquired primarily for use in Atlantic Canada and acquired:	
– after March 28, 2012, and before 2014	10 %
– after 2013 and before 2016	5 %
– after 2015*	0 %
Expenditures	
If you are a Canadian-controlled private corporation (CCPC), this percentage may apply to the portion that you claim of the SR&ED qualified expenditure pool that does not exceed your expenditure limit (see Part 10)	35 %
Note: If your current year's qualified expenditures are more than the corporation's expenditure limit (see Part 10), the excess is eligible for an ITC calculated at the 20 % rate**.	
If you are a corporation that is not a CCPC and have incurred qualified expenditures for SR&ED in any area in Canada:	
– before 2014**	20 %
– after 2013**	15 %
If you are a taxable Canadian corporation that incurred pre-production mining expenditures before March 29, 2012	10 %
If you are a taxable Canadian corporation that incurred pre-production mining exploration expenditures***:	
– after March 28, 2012, and before 2013	10 %
– in 2013	5 %
– after 2013***	0 %
If you are a taxable Canadian corporation that incurred pre-production mining development expenditures****:	
– after March 28, 2012, and before 2014****	10 %
– in 2014	7 %
– in 2015	4 %
– after 2015****	0 %
If you paid salary and wages to apprentices in the first 24 months of their apprenticeship contract for employment	10 %
If you incurred eligible expenditures after March 18, 2007, for the creation of licensed child care spaces for the children of your employees and, potentially, for other children	25 %

* A transitional relief rate of 10% may apply to property acquired after 2013 and before 2017, if the property is acquired under a written agreement entered into before March 29, 2012, or the property is acquired as part of a **phase** of a project where the construction or the engineering and design work for the construction started before March 29, 2012. See paragraph (a.1) of the definition of **specified percentage** in subsection 127(9) for more information.

** The reduction of the rate from 20% to 15% applies to 2014 and later tax years, except that, for 2014 tax years that start before 2014, the reduction is pro-rated based on the number of days in the tax year that are after 2013.

*** Pre-production mining exploration expenditures are described in subparagraph (a)(i) of the definition of **pre-production mining expenditure** in subsection 127(9).

**** A transitional relief rate of 10% may apply to expenditures incurred after 2013 and before 2016, if the expenditure is incurred under a written agreement entered into before March 29, 2012, or the expenditure is incurred as part of the development of a new mine where the construction or the engineering and design work for the construction of the new mine started before March 29, 2012. See subparagraph (k)(ii) of the definition of **specified percentage** in subsection 127(9) for more information. Pre-production mining development expenditures are described in subparagraph (a)(ii) of the definition of **pre-production mining expenditure** in subsection 127(9).

Corporation's name	Business number	Tax year-end Year Month Day
Brantford Power Inc.	86585 8773 RC0001	2015-12-31

Part 2 – Determination of a qualifying corporation

Is the corporation a qualifying corporation? . . . . 101 1 Yes [X] 2 No [ ]

For the purpose of a refundable ITC, a **qualifying corporation** is defined under subsection 127.1(2). The corporation has to be a CCPC and its taxable income (before any loss carrybacks) for its previous tax year cannot be more than its **qualifying income limit** for the particular tax year. If the corporation is associated with any other corporations during the tax year, the total of the taxable incomes of the corporation and the associated corporations (before any loss carrybacks), for their last tax year ending in the previous calendar year, cannot be more than their qualifying income limit for the particular tax year.

Note: A CCPC calculating a refundable ITC is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of both corporations; and
- one of the corporations has at least one shareholder who is not common to both corporations.

If you are a **qualifying** corporation, you will earn a **100%** refund on your share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund*.

Some CCPCs that are **not qualifying** corporations may also earn a **100%** refund on their share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The expenditure limit can be determined in Part 10. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund*.

The 100% refund will not be available to a corporation that is an **excluded corporation** as defined under subsection 127.1(2). A corporation is an excluded corporation if, at any time during the year, it is a corporation that is either controlled by (directly or indirectly, in any manner whatever) or is related to:

a) one or more persons exempt from Part I tax under section 149;

b) Her Majesty in right of a province, a Canadian municipality, or any other public authority; or

c) any combination of persons referred to in a) or b) above.

* Capital expenditures incurred after December 31, 2013, including lease payments for property that would have been a capital expenditure if purchased directly, are **not** qualified SR&ED expenditures and are **not** eligible for an ITC on SR&ED expenditures.

Part 3 – Corporations in the farming industry

Complete this area if the corporation is making SR&ED contributions.

Is the corporation claiming a contribution in the current year to an agricultural organization whose goal is to finance SR&ED work (for example, check-off dues)? . . . . 102 1 Yes [ ] 2 No [X]

Contributions to agricultural organizations for SR&ED* . . . . 103 ________

If **yes**, complete Schedule 125, *Income Statement Information*, to identify the type of farming industry the corporation is involved in. For more information on Schedule 125, see Guide RC4088, *General Index of Financial Information (GIFI)*. Enter contributions on line 350 of Part 8.

* Enter only contributions not already included on Form T661.
Include 80% of the contributions made **after** 2012; for contributions made **before** 2013, include all of the contributions.

Qualified Property and Qualified Resource Property

Part 4 – Eligible investments for qualified property and qualified resource property from the current tax year

Capital cost allowance class number 105	Description of investment 110	Date available for use 115	Location used (province or territory) 120	Amount of investment 125

Total of investments for qualified property and qualified resource property ________ A1

Part 5 – Current-year credit and account balances – ITC from investments in qualified property and qualified resource property

ITC at the end of the previous tax year				B1
Deduct:				
Credit deemed as a remittance of co-op corporations	210			
Credit expired	215			
Subtotal (line 210 **plus** line 215)			▶	C1
ITC at the beginning of the tax year (amount B1 **minus** amount C1)			220	
Add:				
Credit transferred on amalgamation or wind-up of subsidiary	230			
ITC from repayment of assistance	235			
Qualified property; and qualified resource property acquired after March 28, 2012, and before January 1, 2014* (applicable part from amount A1 in Part 4) ____ x 10 % =	240			
Qualified resource property acquired after December 31, 2013, and before January 1, 2016 (applicable part from amount A1 in Part 4) ____ x 5 % =	242			
Credit allocated from a partnership	250			
Subtotal (total of lines 230 to 250)			▶	D1
Total credit available (line 220 **plus** amount D1)				E1
Deduct:				
Credit deducted from Part I tax (enter at amount D8 in Part 30)	260			
Credit carried back to the previous year(s) (from amount H1 in Part 6)			a	
Credit transferred to offset Part VII tax liability	280			
Subtotal (total of line 260, amount a, and line 280)			▶	F1
Credit balance before refund (amount E1 **minus** amount F1)				G1
Deduct:				
Refund of credit claimed on investments from qualified property and qualified resource property (from Part 7)			310	
ITC closing balance of investments from qualified property and qualified resource property (amount G1 **minus** line 310)			320	

* Include investments acquired after 2013 and before 2017 that are eligible for transitional relief.

Part 6 – Request for carryback of credit from investments in qualified property and qualified resource property

	Year	Month	Day			
1st previous tax year				Credit to be applied	901	
2nd previous tax year				Credit to be applied	902	
3rd previous tax year				Credit to be applied	903	
				Total of lines 901 to 903 (enter amount H1 on line a in Part 5)		H1

Part 7 – Refund of ITC for qualifying corporations on investments from qualified property and qualified resource property

Current-year ITCs (total of lines 240, 242, and 250 in Part 5)		I1
Credit balance before refund (from amount G1 in Part 5)		J1
Refund (40 % of amount I1 or J1, whichever is less)		K1

Enter amount K1 or a lesser amount on line 310 in Part 5 (also enter it on line 780 of the T2 return if the corporation does not claim an SR&ED ITC refund).

SR&ED

Part 8 – Qualified SR&ED expenditures

Current expenditures (from line 557 on Form T661)				
Contributions to agricultural organizations for SR&ED				
Deduct: Government assistance, non-government assistance, or contract payment				
Contributions to agricultural organizations for SR&ED for the federal ITC (this amount is updated to line 103 of Part 3. For more details, consult the Help.)*		+		
Current expenditures (line 557 on Form T661 **plus** line 103 in Part 3)*			350	
Capital expenditures incurred **before** 2014 (from line 558 on Form T661)**			360	
Repayments made in the year (from line 560 on Form T661)			370	
Qualified SR&ED expenditures (total of lines 350 to 370)			380	

* If you are claiming only contributions made to agricultural organizations for SR&ED, line 350 should equal line 103 in Part 3. Do not file Form T661.

** Capital expenditures incurred after December 31, 2013, are not qualified SR&ED expenditures. Capital cost allowance can be claimed for depreciable property acquired for use in SR&ED after 2013.

Part 9 – Components of the SR&ED expenditure limit calculation

Part 9 only applies if the corporation is a CCPC.

Note: A CCPC that calculates an SR&ED expenditure limit is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of the corporation; and
- one of the corporations has at least one shareholder who is not common to both corporations.

Is the corporation associated with another CCPC for the purpose of calculating the SR&ED expenditure limit? 385 1 Yes [ ] 2 No [X]

Complete lines 390 and 398 if you answered **no** to the question on line 385 above or if the corporation is not associated with any other corporations (the amounts for associated corporations will be determined on Schedule 49).

Enter your taxable income for the previous tax year* (prior to any loss carry-backs applied)		390	
Enter your taxable capital employed in Canada for the previous tax year minus $10 million. If this amount is nil or negative, enter "0". If this amount is over $40 million, enter $40 million	44,092,266	398	34,092,266

* If either of the tax years referred to on line 390 is less than 51 weeks, **multiply** the taxable income by the following result: 365 **divided** by the number of days in these tax years.

Part 10 – SR&ED expenditure limit for a CCPC

For a stand-alone corporation:		$ 8,000,000	
Deduct: Taxable income for the previous tax year (from line 390 in Part 9) or $500,000, whichever is more	500,000 x 10 =	5,000,000	A2
Excess ($8,000,000 **minus** amount A2; if negative, enter "0")		3,000,000	B2
$ 40,000,000 **minus** line 398 in Part 9	5,907,734 a		
Amount a **divided** by $ 40,000,000		0.14769	C2
Expenditure limit for the stand-alone corporation (amount B2 **multiplied** by amount C2)*		443,070	D2
For an associated corporation: If associated, the allocation of the SR&ED expenditure limit as provided on Schedule 49*	400		E2
Where the tax year of the corporation is less than 51 weeks, calculate the amount of the expenditure limit as follows:			
Amount D2 or E2 ____ x Number of days in the tax year / 365	365 =		F2
Your SR&ED expenditure limit for the year (enter the amount from amount D2, E2, or F2, whichever applies)	410	443,070	

* Amount D2 or E2 cannot be more than $3,000,000.

Part 11 – Investment tax credits on SR&ED expenditures

Current expenditures (from line 350 in Part 8) or the expenditure limit (from line 410 in Part 10), whichever is less*	420		x	35 %	=	G2
Line 350 **minus** line 410 (if negative, enter "0")	430		x	15 **%	=	H2
Line 410 **minus** line 350 (if negative, enter "0")		443,070 b				
Capital expenditures (from line 360 in Part 8) or amount b above, whichever is less*	440		x	35 %	=	I2
Line 360 **minus** amount b above (if negative, enter "0")	450		x	15 **%	=	J2

Repayments (amount from line 370 in Part 8) . . . . ______

If a corporation makes a repayment of any government or non-government assistance, or contract payments that reduced the amount of qualified expenditures for ITC purposes, the amount of the repayment is eligible for a credit.***

460		x	35 %	=	c
480		x	15 %	=	d

Subtotal (amount c **plus** amount d) ______ ▶ ______ K2

Current-year SR&ED ITC (total of amounts G2 to K2; enter on line 540 in Part 12) . . . . . . ______ L2

* For corporations that are not CCPCs, enter "0" for amounts G2 and I2.

** For tax years that end after 2013, the general SR&ED ITC rate is reduced from 20% to 15%, except that, for 2014 tax years that start before 2014, the reduction is pro-rated based on the number of days in the tax year that are after 2013. If your rate is different than 15%, enter the amounts at lines 430 or 450 and use the appropriate rate instead of 15%.

*** The ITC on the repayment (the credit) is calculated using the ITC rate that you used to determine your ITC at the time your qualified expenditures for ITC purposes were reduced because of the government or non-government assistance, or contract payments. Enter the amount of the repayment on the line that corresponds to the appropriate rate. If the rate is different than 20% or 35%, enter the amount at line 480 and use the appropriate rate instead of 20%.

Part 12 – Current-year credit and account balances – ITC from SR&ED expenditures

ITC at the end of the previous tax year . . . . . . ______ M2

Deduct:

Credit deemed as a remittance of co-op corporations	510	
Credit expired	515	

Subtotal (line 510 **plus** line 515) ______ ▶ ______ N2

ITC at the beginning of the tax year (amount M2 **minus** amount N2) . . . . . . 520 ______

Add:

Credit transferred on amalgamation or wind-up of subsidiary	530	
Total current-year credit (from amount L2 in Part 11)	540	
Credit allocated from a partnership	550	

Subtotal (total of lines 530 to 550) ______ ▶ ______ O2

Total credit available (line 520 **plus** amount O2) . . . . . . ______ P2

Deduct:

Credit deducted from Part I tax (enter at amount E8 in Part 30)	560	
Credit carried back to the previous year(s) (from amount S2 in Part 13)		e
Credit transferred to offset Part VII tax liability	580	

Subtotal (total of line 560, amount e, and line 580) ______ ▶ ______ Q2

Credit balance before refund (amount P2 **minus** amount Q2) . . . . . . ______ R2

Deduct:

Refund of credit claimed on SR&ED expenditures (from Part 14 or 15, whichever applies) . . . . . . 610 ______

ITC closing balance on SR&ED (amount R2 **minus** line 610) . . . . . . 620 ______

Part 13 – Request for carryback of credit from SR&ED expenditures

	Year	Month	Day			
1st previous tax year				Credit to be applied	911	
2nd previous tax year				Credit to be applied	912	
3rd previous tax year				Credit to be applied	913	

Total of lines 911 to 913 (enter amount S2 at line e in Part 12) ______ S2

Part 14 – Refund of ITC for qualifying corporations – SR&ED

Complete this part only if you are a qualifying corporation as determined on line 101 in Part 2.

Is the corporation an excluded corporation as defined under subsection 127.1(2)? . . . . 650 1 Yes [ ] 2 No [X]

Current-year ITC (lines 540 **plus** 550 in Part 12 **minus** amount K2 in Part 11) . . . . . . ______ f

Refundable credits (amount f or amount R2 in Part 12, whichever is less)* . . . . . . ______ T2

Deduct:

Amount T2 or amount G2 in Part 11, whichever is less . . . . . . ______ U2

Net amount (amount T2 **minus** amount U2; if negative, enter "0") . . . . . . ______ V2

Amount V2 **multiplied** by 40 % . . . . . . ______ W2

Add:

Amount U2 . . . . . . ______ X2

Refund of ITC (amount W2 **plus** amount X2 – enter this, or a lesser amount, on line 610 in Part 12) . . . . . . ______ Y2

Enter the total of line 310 in Part 5 and line 610 in Part 12 on line 780 of the T2 return.

* If you are also an excluded corporation, as defined in subsection 127.1(2), this amount must be multiplied by 40%. Claim this, or a lesser amount, as your refund of ITC for amount Y2.

Part 15 – Refund of ITC for CCPCs that are not qualifying or excluded corporations – SR&ED

Complete this box only if you are a CCPC that is not a qualifying or excluded corporation as determined on line 101 in Part 2.

Credit balance before refund (from amount R2 in Part 12) . . . . . . ______ Z2

Deduct:

Amount Z2 or amount G2 in Part 11, whichever is less . . . . . . ______ AA2

Net amount (amount Z2 **minus** amount AA2; if negative, enter "0") . . . . . . ______ BB2

Amount BB2 or amount I2 in Part 11, whichever is less . . . . . . ______ CC2

Amount CC2 **multiplied** by 40 % . . . . . . ______ DD2

Add :

Amount AA2 . . . . . . ______ EE2

Refund of ITC (amount DD2 **plus** amount EE2) . . . . . . ______ FF2

Enter FF2, or a lesser amount, on line 610 in Part 12 and also on line 780 of the T2 return.

Recapture – SR&ED

Part 16 – Recapture of ITC for corporations and corporate partnerships – SR&ED

You will have a recapture of ITC in a year when **all** of the following conditions are met:

- you acquired a particular property in the current year or in any of the 20 previous tax years, if the credit was earned in a tax year ending after 1997 and did not expire before 2008;
- you claimed the cost of the property as a qualified expenditure for SR&ED on Form T661;
- the cost of the property was included in calculating your ITC or was the subject of an agreement made under subsection 127(13) to transfer qualified expenditures; and
- you disposed of the property or converted it to commercial use after February 23, 1998. This condition is also met if you disposed of or converted to commercial use a property that incorporates the particular property previously referred to.

Note:

The recapture **does not apply** if you disposed of the property to a non-arm's-length purchaser who intended to use it all or substantially all for SR&ED. When the non-arm's-length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical ITC rate of the original user.

You will report a recapture on the T2 return for the year in which you disposed of the property or converted it to commercial use. In the following tax year, add the amount of the ITC recapture to the SR&ED expenditure pool.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

Calculation 1 – If you meet all of the above conditions

Amount of ITC you originally calculated for the property you acquired, or the original user's ITC where you acquired the property from a non-arm's length party, as described in the **note** above 700	Amount calculated using ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) 710	Amount from column 700 or 710, whichever is less

Subtotal (enter amount A3 on line C3 in Part 17) ______ A3

Calculation 2 – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil on line B3.

A Rate that the transferee used in determining its ITC for qualified expenditures under a subsection 127(13) agreement 720	B Proceeds of disposition of the property if you dispose of it to an arm's length person; or, in any other case, enter the fair market value of the property at conversion or disposition 730	C Amount, if any, already provided for in Calculation 1 (This allows for the situation where only part of the cost of a property is transferred under a subsection 127(13) agreement.) 740	D Amount determined by the formula (A x B) – C	E ITC earned by the transferee for the qualified expenditures that were transferred 750	F Amount from column D or E, whichever is less

Subtotal (total of column F) (enter amount B3 on line D3 in Part 17) ______ B3

Part 16 – Recapture of ITC for corporations and corporate partnerships – SR&ED (continued)

Calculation 3

As a member of the partnership, you will report your share of the SR&ED ITC of the partnership after the SR&ED ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 550 in Part 12. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line 760.

Corporate partner's share of the excess of SR&ED ITC (amount to be reported on line E3 in Part 17) **760** ____________

Part 17 – Total recapture of SR&ED investment tax credit

Recaptured ITC from calculation 1, amount A3 in Part 16		C3
Recaptured ITC from calculation 2, amount B3 in Part 16		D3
Recaptured ITC from calculation 3, line 760 in Part 16		E3
Total recapture of SR&ED investment tax credit (total of amounts C3 to E3)		F3

Enter amount F3 on line A8 in Part 29.

Pre-Production Mining

Part 18 – Pre-production mining expenditures

Exploration information

A mineral resource that qualifies for the credit means a mineral deposit from which the principal mineral to be extracted is diamond, a base or precious metal deposit, or a mineral deposit from which the principal mineral to be extracted is an industrial mineral that, when refined, results in a base or precious metal.

In column 800, list all minerals for which pre-production mining expenditures have taken place in the tax year.

For each of the minerals reported in column 800, identify each project (in column 805), mineral title (in column 806), and mining division (in column 807) where title is registered. If there is no mineral title, identify only the project and mining division.

List of minerals 800	Project name 805

Mineral title 806	Mining division 807

Pre-production mining expenditures*

Exploration:

Pre-production mining expenditures that the corporation incurred in the tax year for the purpose of determining the existence, location, extent, or quality of a mineral resource in Canada:

Prospecting 810

Geological, geophysical, or geochemical surveys 811

Drilling by rotary, diamond, percussion, or other methods 812

Trenching, digging test pits, and preliminary sampling 813

Development:

Pre-production mining expenditures incurred in the tax year for bringing a new mine in a mineral resource in Canada into production in reasonable commercial quantities and incurred before the new mine comes into production in such quantities:

Clearing, removing overburden, and stripping 820

Sinking a mine shaft, constructing an adit, or other underground entry 821

Other pre-production mining expenditures incurred in the tax year:

Description 825	Amount 826

Total of column 826 ► A4

Total pre-production mining expenditures (total of lines 810 to 821 and amount A4) 830

Deduct:

Total of all assistance (grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to on line 830 above 832

Excess (line 830 **minus** line 832) (if negative, enter "0") B4

Add:

Repayments of government and non-government assistance 835

Pre-production mining expenditures (amount B4 **plus** line 835) C4

* A pre-production mining expenditure is defined under subsection 127(9).

Part 19 – Current-year credit and account balances – ITC from pre-production mining expenditures

ITC at the end of the previous tax year D4

Deduct:

Credit deemed as a remittance of co-op corporations 841

Credit expired 845

Subtotal (line 841 **plus** line 845) ► E4

ITC at the beginning of the tax year (amount D4 **minus** amount E4) 850

Add:

Credit transferred on amalgamation or wind-up of subsidiary 860

Pre-production mining expenditures* incurred before January 1, 2013 (applicable part from amount C4 in Part 18)	870	x	10 %	=	a
Pre-production mining exploration expenditures incurred in 2013 (applicable part from amount C4 in Part 18)	872	x	5 %	=	b
Pre-production mining development expenditures incurred in 2014 (applicable part from amount C4 in Part 18)	874	x	7 %	=	c
Pre-production mining development expenditures incurred in 2015 (applicable part from amount C4 in Part 18)	876	x	4 %	=	d

Current year credit (total of amounts a to d) 880 ► F4

Total credit available (total of lines 850, 860, and amount F4) G4

Deduct:

Credit deducted from Part I tax (enter at amount F8 in Part 30) 885

Credit carried back to the previous year(s) (from amount I4 in Part 20) . . . . e

Subtotal (line 885 **plus** amount e) ► H4

ITC closing balance from pre-production mining expenditures (amount G4 **minus** amount H4) 890

* Also include pre-production mining development expenditures incurred before 2014 and pre-production mining development expenditures incurred after 2013 and before 2016 that are eligible for transitional relief.

Part 20 – Request for carryback of credit from pre-production mining expenditures

	Year	Month	Day		
1st previous tax year				Credit to be applied	921
2nd previous tax year				Credit to be applied	922
3rd previous tax year				Credit to be applied	923

Total of lines 921 to 923 (enter amount I4 on line e in Part 19) I4

Apprenticeship Job Creation

Part 21 – Total current-year credit – ITC from apprenticeship job creation expenditures

If you are a related person as defined under subsection 251(2), has it been agreed in writing that you are the only employer who will be claiming the apprenticeship job creation tax credit for this tax year for each apprentice whose contract number (or social insurance number or name) appears below? (If not, you cannot claim the tax credit.) . . . . 611 1 Yes [ ] 2 No [ ]

For each apprentice in their first 24 months of the apprenticeship, enter the apprenticeship contract number registered with Canada, or a province or territory, under an apprenticeship program designed to certify or license individuals in the trade. For the province, the trade must be a Red Seal trade. If there is no contract number, enter the social insurance number (SIN) or the name of the eligible apprentice.

	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605	
1.	110955a	Powerline technician	13,169	1,317	1,317	
			Total current-year credit (total of column E) (enter amount A5 on line 640 in Part 22)		1,317	A5

* Other than qualified expenditure incurred, and net of any other government or non-government assistance received or to be received.

Part 22 – Current-year credit and account balances – ITC from apprenticeship job creation expenditures

ITC at the end of the previous tax year				B5
Deduct:				
Credit deemed as a remittance of co-op corporations	612			
Credit expired after 20 tax years	615			
Subtotal (line 612 **plus** line 615)			►	C5
ITC at the beginning of the tax year (amount B5 **minus** amount C5)			625	
Add:				
Credit transferred on amalgamation or wind-up of subsidiary	630			
ITC from repayment of assistance	635			
Total current-year credit (from amount A5 in Part 21)	640	1,317		
Credit allocated from a partnership	655			
Subtotal (total of lines 630 to 655)		1,317	► 1,317	D5
Total credit available (line 625 **plus** amount D5)			1,317	E5
Deduct:				
Credit deducted from Part I tax (enter on line G8 in Part 30)	660			
Credit carried back to the previous year(s) (from amount G5 in Part 23)			a	
Subtotal (line 660 **plus** amount a)			►	F5
ITC closing balance from apprenticeship job creation expenditures (amount E5 **minus** amount F5)			690 1,317	

Part 23 – Request for carryback of credit from apprenticeship job creation expenditures

	Year	Month	Day			
1st previous tax year				Credit to be applied	931	
2nd previous tax year				Credit to be applied	932	
3rd previous tax year				Credit to be applied	933	
				Total of lines 931 to 933 (enter amount G5 on line a in Part 22)		G5

Child Care Spaces

Part 24 – Eligible child care spaces expenditures

Enter the eligible expenditures that the corporation incurred to create licensed child care spaces for the children of the employees and, potentially, for other children. The corporation cannot be carrying on a child care services business. The eligible expenditures include:

- the cost of depreciable property (other than specified property); and
- the specified child care start-up expenditures;

acquired or incurred only to create new child care spaces at a licensed child care facility.

Cost of depreciable property from the current tax year

	Capital cost allowance class number 665	Description of investment 675	Date available for use 685	Amount of investment 695
1.				

Total cost of depreciable property from the current tax year (total of column 695) 715 ______

Add:

Specified child care start-up expenditures from the current tax year . . . . 705 ______

Total gross eligible expenditures for child care spaces (line 715 **plus** line 705) . . . . ______ A6

Deduct:

Total of all assistance (including grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to in amount A6 . . . . 725 ______

Excess (amount A6 **minus** line 725) (if negative, enter "0") . . . . ______ B6

Add:

Repayments by the corporation of government and non-government assistance . . . . 735 ______

Total eligible expenditures for child care spaces (amount B6 **plus** line 735) . . . . 745 ______

Part 25 – Current-year credit – ITC from child care spaces expenditures

The credit is equal to 25% of eligible child care spaces expenditures incurred to a maximum of $10,000 per child care space created in a licensed child care facility.

Eligible expenditures (from line 745 in Part 24) . . . . ______ x 25 % = ______ C6

Number of child care spaces . . . . 755 ______ x $ 10,000 = ______ D6

ITC from child care spaces expenditures (amount C6 or D6, whichever is less) . . . . ______ E6

Part 26 – Current-year credit and account balances – ITC from child care spaces expenditures

ITC at the end of the previous tax year				F6
Deduct:				
Credit deemed as a remittance of co-op corporations	765			
Credit expired after 20 tax years	770			
Subtotal (line 765 **plus** line 770)			▶	G6
ITC at the beginning of the tax year (amount F6 **minus** amount G6)		775		
Add:				
Credit transferred on amalgamation or wind-up of subsidiary	777			
Total current-year credit (from amount E6 in Part 25)	780			
Credit allocated from a partnership	782			
Subtotal (total of lines 777 to 782)			▶	H6
Total credit available (line 775 **plus** amount H6)				I6
Deduct:				
Credit deducted from Part I tax (enter on line H8 in Part 30)	785			
Credit carried back to the previous year(s) (from amount K6 in Part 27)		a		
Subtotal (line 785 **plus** amount a)			▶	J6
ITC closing balance from child care spaces expenditures (amount I6 **minus** amount J6)		790		

Part 27 – Request for carryback of credit from child care space expenditures

	Year / Month / Day			
1st previous tax year	2014-12-31	Credit to be applied	941	
2nd previous tax year	2013-12-31	Credit to be applied	942	
3rd previous tax year	2012-12-31	Credit to be applied	943	
		Total of lines 941 to 943 (enter amount K6 on line a in Part 26)		K6

Recapture – Child Care Spaces

Part 28 – Recapture of ITC for corporations and corporate partnerships – Child care spaces

The ITC will be recovered against the taxpayer's tax otherwise payable under Part I of the Act if, at any time within 60 months of the day on which the taxpayer acquired the property:

- the new child care space is no longer available; or
- property that was an eligible expenditure for the child care space is:
  - disposed of or leased to a lessee; or
  - converted to another use.

If the property disposed of is a child care space, the amount that can reasonably be considered to have been included in the original ITC (paragraph 127(27.12)(a)) . . . . **792** ______

In the case of eligible expenditures (paragraph 127(27.12)(b)), the lesser of:

The amount that can reasonably be considered to have been included in the original ITC . . . . **795** ______

25% of either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value (in any other case) of the property . . . . **797** ______

Amount from line 795 or line 797, whichever is less . . . . ______ A7

Corporate partnerships

As a member of the partnership, you will report your share of the child care spaces ITC of the partnership after the child care spaces ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 782 in Part 26. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line 799 below.

Corporate partner's share of the excess of ITC **799** ______

Total recapture of child care spaces investment tax credit (total of line 792, amount A7, and line 799) . . . . ______ B7
Enter amount B7 on line B8 in Part 29.

Summary of Investment Tax Credits

Part 29 – Total recapture of investment tax credit

Recaptured SR&ED ITC (from amount F3 in Part 17) . . . . ______ A8

Recaptured child care spaces ITC (from amount B7 in Part 28) . . . . ______ B8

Total recapture of investment tax credit (amount A8 **plus** amount B8) . . . . ______ C8
Enter amount C8 on line 602 of the T2 return.

Part 30 – Total ITC deducted from Part I tax

ITC from investments in qualified property deducted from Part I tax (from line 260 in Part 5) . . . . ______ D8

ITC from SR&ED expenditures deducted from Part I tax (from line 560 in Part 12) . . . . ______ E8

ITC from pre-production mining expenditures deducted from Part I tax (from line 885 in Part 19) . . . . ______ F8

ITC from apprenticeship job creation expenditures deducted from Part I tax (from line 660 in Part 22) . . . . ______ G8

ITC from child care space expenditures deducted from Part I tax (from line 785 in Part 26) . . . . ______ H8

Total ITC deducted from Part I tax (total of amounts D8 to H8) . . . . ______ I8
Enter amount I8 on line 652 of the T2 return.

Attached Schedule with Total

C – Eligible salary and wages

Title C – Eligible salary and wages

Explanatory note

Total wages paid = $49,698 - can claim from 2013-04-08 to 2015-04-07, therefore claim $49,698 * (97/365)

Description	Amount
per formula - wages up to April 7, 2015	13,169 00
Total	13,169 00

Summary of Investment Tax Credit Carryovers

Continuity of investment tax credit carryovers

CCA class number 97 Apprenticeship job creation ITC

Current year

Addition current year (A)	Applied current year (B)	Claimed as a refund (C)	Carried back (D)	ITC end of year (A-B-C-D)
1,317				1,317

Prior years

Taxation year	ITC beginning of year (E)	Adjustments (F)	Applied current year (G)	ITC end of year (E-F-G)
2014-12-31				
2013-12-31				
2012-12-31				
2011-12-31				
2010-12-31				
2009-12-31				
2008-12-31				
2007-12-31				
2006-12-31				
2005-12-31				*
2004-12-31				
2003-12-31				
2002-12-31				
2001-12-31				
2000-12-31				
				*
Total				

B+C+D+G **Total ITC utilized**

* The **ITC end of year** includes the amount of ITC expired from the 10th preceding year if it is before January 1, 1998, or the amount of ITC expired from the 20th preceding year if it is after December 31, 1997. Note that this credit expires at the end of the tax year and any expired credit will be posted to line 215, 515, 615, 770 or 845, as applicable, in Schedule 31 the following year.

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Schedule 33

Taxable Capital Employed in Canada – Large Corporations

Corporation's name	Business number	Tax year-end Year Month Day
Brantford Power Inc.	86585 8773 RC0001	2015-12-31

- Use this schedule in determining if the total taxable capital employed in Canada of the corporation (other than a financial institution or an insurance corporation) and its related corporations is greater than $10,000,000.
- If the total taxable capital employed in Canada of the corporation and its related corporations is greater than $10,000,000, file a completed Schedule 33 with your T2 *Corporation Income Tax Return* no later than six months from the end of the tax year.
- Unless otherwise noted, all legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 181(1) defines the terms **financial institution**, **long-term debt**, and **reserves**.
- Subsection 181(3) provides the basis to determine the carrying value of a corporation's assets or any other amount under Part I.3 for its capital, investment allowance, taxable capital, or taxable capital employed in Canada, or for a partnership in which it has an interest.
- If the corporation was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada, go to Part 4, **Taxable capital employed in Canada**.

Part 1 – Capital

Add the following year-end amounts:

	Line	Amount		
Reserves that have not been deducted in calculating income for the year under Part I	101			
Capital stock (or members' contributions if incorporated without share capital)	103	22,437,505		
Retained earnings	104	18,639,595		
Contributed surplus	105			
Any other surpluses	106			
Deferred unrealized foreign exchange gains	107			
All loans and advances to the corporation	108	43,726,567		
All indebtedness of the corporation represented by bonds, debentures, notes, mortgages, hypothecary claims, bankers' acceptances, or similar obligations	109			
Any dividends declared but not paid by the corporation before the end of the year	110			
All other indebtedness of the corporation (other than any indebtedness for a lease) that has been outstanding for more than 365 days before the end of the year	111			
The total of all amounts, each of which is the amount, if any, in respect of a partnership in which the corporation held a membership interest at the end of the year, either directly or indirectly through another partnership (see note below)	112			
Subtotal (**add** lines 101 to 112)		84,803,667	84,803,667	A

Note:

Line 112 is determined by the formula (A – B) x C/D (as per paragraph 181.2(3)(g)) where:

A is the total of all amounts that would be determined for lines 101, 107, 108, 109, and 111 in respect of the partnership for its last fiscal period that ends at or before the end of the year if
- a) those lines applied to partnerships in the same manner that they apply to corporations, and
- b) those amounts were computed without reference to amounts owing by the partnership
  - (i) to any corporation that held a membership interest in the partnership either directly or indirectly through another partnership, or
  - (ii) to any partnership in which a corporation described in subparagraph (i) held a membership interest either directly or indirectly through another partnership.

B is the partnership's deferred unrealized foreign exchange losses at the end of the period,

C is the share of the partnership's income or loss for the period to which the corporation is entitled either directly or indirectly through another partnership, and

D is the partnership's income or loss for the period.

Part 1 – Capital (continued)

Subtotal A (from page 1)			84,803,667 A
Deduct the following amounts:			
Deferred tax debit balance at the end of the year	121		
Any deficit deducted in calculating its shareholders' equity (including, for this purpose, the amount of any provision for the redemption of preferred shares) at the end of the year	122		
To the extent that the amount may reasonably be regarded as being included in any of lines 101 to 112 above for the year, any amount deducted under subsection 135(1) in calculating income under Part I for the year.	123		
Deferred unrealized foreign exchange losses at the end of the year	124		
Subtotal (**add** lines 121 to 124)		▶	B
Capital for the year (amount A **minus** amount B) (if negative, enter "0")	190		84,803,667

Part 2 – Investment allowance

Add the carrying value at the end of the year of the following assets of the corporation:

A share of another corporation	401	
A loan or advance to another corporation (other than a financial institution)	402	331,631
A bond, debenture, note, mortgage, hypothecary claim, or similar obligation of another corporation (other than a financial institution)	403	
Long-term debt of a financial institution	404	
A dividend payable on a share of the capital stock of another corporation	405	
A loan or advance to, or a bond, debenture, note, mortgage, hypothecary claim or similar obligation of, a partnership each member of which was, throughout the year, another corporation (other than a financial institution) that was not exempt from tax under this Part (otherwise than because of paragraph 181.1(3)(*d*)), or another partnership described in paragraph 181.2(4)(*d.1*)	406	
An interest in a partnership (see note 2 below)	407	
Investment allowance for the year (add lines 401 to 407)	490	331,631

Notes:

1. Lines 401 to 405 should not include the carrying value of a share of the capital stock of, a dividend payable by, or indebtedness of a corporation that is exempt from tax under Part I.3 (other than a non-resident corporation that at no time in the year carried on business in Canada through a permanent establishment).
2. Where the corporation has an interest in a partnership held either directly or indirectly through another partnership, refer to subsection 181.2(5) for additional rules regarding the carrying value of an interest in a partnership.
3. Where a trust is used as a conduit for loaning money from a corporation to another related corporation (other than a financial institution), the loan will be considered to have been made directly from the lending corporation to the borrowing corporation. Refer to subsection 181.2(6) for special rules that may apply.

Part 3 – Taxable capital

Capital for the year (line 190)		84,803,667	C
Deduct: Investment allowance for the year (line 490)		331,631	D
Taxable capital for the year (amount C **minus** amount D) (if negative, enter "0")	500	84,472,036	

Part 4 – Taxable capital employed in Canada

To be completed by a corporation that was resident in Canada at any time in the year

Taxable capital for the year (line 500)	84,472,036	x	Taxable income earned in Canada **610**	1,000	= **Taxable capital employed in Canada** **690**	84,472,036
			Taxable income	1,000		

Notes: 1. Regulation 8601 gives details on calculating the amount of taxable income earned in Canada.
2. Where a corporation's taxable income for a tax year is "0," it shall, for the purposes of the above calculation, be deemed to have a taxable income for that year of $1,000.
3. In the case of an airline corporation, Regulation 8601 should be considered when completing the above calculation.

To be completed by a corporation that was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada

Total of all amounts each of which is the carrying value at the end of the year of an asset of the corporation used in the year or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada . . . . **701** ____

Deduct the following amounts:

Corporation's indebtedness at the end of the year [other than indebtedness described in any of paragraphs 181.2(3)(c) to (f)] that may reasonably be regarded as relating to a business it carried on during the year through a permanent establishment in Canada . . . . **711** ____

Total of all amounts each of which is the carrying value at the end of year of an asset described in subsection 181.2(4) of the corporation that it used in the year, or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada . . . . **712** ____

Total of all amounts each of which is the carrying value at the end of year of an asset of the corporation that is a ship or aircraft the corporation operated in international traffic, or personal or movable property used or held by the corporation in carrying on any business during the year through a permanent establishment in Canada (see note below) . . . . **713** ____

Total deductions (**add** lines 711, 712, and 713) ____ ► ____ E

Taxable capital employed in Canada (line 701 **minus** amount E) (if negative, enter "0") . . . . **790** ____

Note: Complete line 713 only if the country in which the corporation is resident did not impose a capital tax for the year on similar assets, or a tax for the year on the income from the operation of a ship or aircraft in international traffic, of any corporation resident in Canada during the year.

Part 5 – Calculation for purposes of the small business deduction

This part is applicable to corporations that are not associated in the current year, but were associated in the prior year.

Taxable capital employed in Canada (amount from line 690)		F
Deduct:	10,000,000	G
Excess (amount F **minus** amount G) (if negative, enter "0")		H
Calculation for purposes of the small business deduction (amount H x 0.225%)		I

Enter this amount at line 415 of the T2 return.

Attached Schedule with Total

Part 1 – All loans and advances to the corporation

Title Part 1 – All loans and advances to the corporation

Description	Amount	
Long Term Debt	40,919,717	00
Current portion LTD	1,141,430	00
Current customer deposits	1,606,069	00
due to affiliate	59,351	00
Total	43,726,567	00

Attached Schedule with Total

Part 1 – Reserves that have not been deducted in calculating income for the year under Part I

Title Part 1 – Reserves that have not been deducted in computing income for th

Description	Amount
Sch. 13	
Total	

Attached Schedule with Total

Part 1 – Deferred tax debit balance at the end of the year

Title Part 1 – Deferred tax debit balance at the end of the year

Description	Amount
ST FTA	
LT FTA	
Total	

Attached Schedule with Total

Part 2 – A loan or advance to another corporation (other than a financial institution)

Title Part 2 – A loan or advance to another corporation (other than a financial ir

Description	Amount	
Prepaids per b/s	331,631	00
Total	331,631	00

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SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
Brantford Power Inc.	86585 8773 RC0001	2015-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

		Provide only one number per shareholder				
	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) 100	Business Number (If a corporation is not registered, enter "NR") 200	Social insurance number 300	Trust number 350	Percentage common shares 400	Percentage preferred shares 500
1	BRANTFORD ENERGY CORPORATION	87504 1329 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

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Schedule 55

Part III.1 Tax on Excessive Eligible Dividend Designations

Corporation's name	Business number	Tax year-end Year Month Day
Brantford Power Inc.	86585 8773 RC0001	2015-12-31

Do not use this area

- Every corporation resident in Canada that pays a taxable dividend (other than a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1)) in the tax year must file this schedule.
- Canadian-controlled private corporations (CCPC) and deposit insurance corporations (DIC) must complete Part 1 of this schedule. All other corporations must complete Part 2.
- Every corporation that has paid an eligible dividend must also file Schedule 53, *General Rate Income Pool (GRIP) Calculation*, or Schedule 54, *Low Rate Income Pool (LRIP) Calculation*, whichever is applicable.
- File the completed schedules with your *T2 Corporation Income Tax Return* no later than six months from the end of the tax year.
- All legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool (GRIP), and low rate income pool (LRIP).
- The calculations in Part 1 and Part 2 do not apply if the excessive eligible dividend designation arises from the application of paragraph (c) of the definition of excessive eligible dividend designation in subsection 89(1). This paragraph applies when an eligible dividend is paid to artificially maintain or increase the GRIP or to artificially maintain or decrease the LRIP.

Part 1 – Canadian-controlled private corporations and deposit insurance corporations

Taxable dividends paid in the tax year **not included** in Schedule 3				
Taxable dividends paid in the tax year **included** in Schedule 3		1,000,000		
Total taxable dividends paid in the tax year	100	1,000,000		
Total eligible dividends paid in the tax year			150	A
GRIP at the end of the tax year (line 590 on Schedule 53) (if negative, enter "0")			160	B
Excessive eligible dividend designation (line 150 **minus** line 160)				C
Deduct:				
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends *			180	D
Subtotal (amount C **minus** amount D)				E
Part III.1 tax on excessive eligible dividend designations – CCPC or DIC (amount E **multiplied** by 20 %)			190	F

Enter the amount from line 190 on line 710 of the T2 return.

Part 2 – Other corporations

Taxable dividends paid in the tax year **not included** in Schedule 3				
Taxable dividends paid in the tax year **included** in Schedule 3				
Total taxable dividends paid in the tax year	200			
Total excessive eligible dividend designations in the tax year (amount from line A of Schedule 54)				G
Deduct:				
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends *			280	H
Subtotal (amount G **minus** amount H)				I
Part III.1 tax on excessive eligible dividend designations – Other corporations (amount I **multiplied** by 20 %)			290	J

Enter the amount from line 290 on line 710 of the T2 return.

* You can elect to treat all or part of your excessive eligible dividend designation as a separate taxable dividend in order to eliminate or reduce the Part III.1 tax otherwise payable. You must file the election on or before the day that is 90 days **after** the day the notice of assessment for Part III.1 tax was sent. We will accept an election before the assessment of the tax. For more information on how to make this election, go to **www.cra.gc.ca/eligibledividends**.

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Schedule 552

Ontario Apprenticeship Training Tax Credit

Corporation's name	Business number	Tax year-end Year Month Day
Brantford Power Inc.	86585 8773 RC0001	2015-12-31

- Use this schedule to claim an Ontario apprenticeship training tax credit (ATTC) under section 89 of the *Taxation Act, 2007* (Ontario).
- The ATTC is a refundable tax credit that is equal to a specified percentage (25% to 45%) of the eligible expenditures incurred by a corporation for a qualifying apprenticeship. For eligible expenditures incurred after March 26, 2009 for an apprenticeship program that began before April 24, 2015, the maximum credit for each qualifying apprenticeship is $10,000 per year to a maximum credit of $40,000 over the first 48-month period of the qualifying apprenticeship. For an apprenticeship program that began after April 23, 2015, the maximum credit for each qualifying apprenticeship is $5,000 per year to a maximum credit of $15,000 over the first 36-month period of the qualifying apprenticeship.
- Eligible expenditures are salaries and wages (including taxable benefits) paid to an apprentice in a qualifying apprenticeship or fees paid to an employment agency for the provision of services performed by the apprentice in a qualifying apprenticeship. These expenditures must be:
  - paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario;
  - for services provided by the apprentice during the first 48 months of the apprenticeship program, if an apprenticeship program began before April 24, 2015; and
  - for services provided by the apprentice during the first 36 months of the apprenticeship program, if an apprenticeship program began after April 23, 2015.
- An expenditure is not eligible for an ATTC if:
  - the same expenditure was used, or will be used, to claim a co-operative education tax credit; or
  - it is more than an amount that would be paid to an arm's length apprentice.
- An apprenticeship must meet the following conditions to be a qualifying apprenticeship:
  - the apprenticeship is in a qualifying skilled trade approved by the Ministry of Training, Colleges and Universities (Ontario) or a person designated by him or her; and
  - the corporation and the apprentice must be participating in an apprenticeship program in which the training agreement has been registered under the *Ontario College of Trades and Apprenticeship Act, 2009, or* the *Apprenticeship and Certification Act, 1998,* or in which the contract of apprenticeship has been registered under the *Trades Qualification and Apprenticeship Act*.
- Do not submit the training agreement or contract of apprenticeship with your *T2 Corporation Income Tax Return*. Keep a copy of the training agreement or contract of apprenticeship to support your claim.
- File this schedule with your *T2 Corporation Income Tax Return*.

Part 1 – Corporate information

110 Name of person to contact for more information: BRIAN D'AMBOISE

120 Telephone number: (519) 751-3522

Is the claim filed for an ATTC earned through a partnership? * . . . . . **150** 1 Yes [ ] 2 No [X]

If you answered **yes** to the question at line 150, what is the name of the partnership? . **160** ______

Enter the percentage of the partnership's ATTC allocated to the corporation . . . . . **170** ______ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 552 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 552 to claim the partner's share of the partnership's ATTC. The total of the partners' allocated amounts can never exceed the amount of the partnership's ATTC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . . **200** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax under Part III of the *Taxation Act, 2007* (Ontario)? . . . . . **210** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, then you are **not eligible** for the ATTC.

Part 3 – Specified percentage

Corporation's salaries and wages paid in the previous tax year * **300** 600,001

For eligible expenditures incurred after March 26, 2009 for an apprenticeship program that began before April 24, 2015:

- If line 300 is $400,000 or less, enter 45% on line 312.
- If line 300 is $600,000 or more, enter 35% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Specified percentage} = 45\% - \left[10\% \times \left(\frac{\text{amount on line 300} \text{ minus } 400{,}000}{200{,}000} \right) \right]$$

Specified percentage . . . . . **312** 35.000 %

For eligible expenditures incurred for an apprenticeship program that began after April 23, 2015:

- If line 300 is $400,000 or less, enter 30% on line 314.
- If line 300 is $600,000 or more, enter 25% on line 314.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 314 using the following formula:

$$\text{Specified percentage} = 30\% - \left[5\% \times \left(\frac{\text{amount on line 300} \text{ minus } 400{,}000}{200{,}000} \right) \right]$$

Specified percentage . . . . . **314** 25.000 %

* If this is the first tax year of an amalgamated corporation and subsection 89(6) of the *Taxation Act, 2007* (Ontario) applies, enter salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Ontario apprenticeship training tax credit

Complete a **separate entry** for each apprentice for each qualifying apprenticeship with the corporation. When claiming an ATTC for repayment of government assistance, complete a **separate entry** for each repayment, and complete columns A to G and M and N with the details for the employment period in the previous tax year in which the government assistance was received.

	A Trade code 400	B Apprenticeship program/trade name 405	C Name of apprentice 410
1.	434a	Powerline Technician	Mark Allen Gehue
2.	434a	Powerline Technician	Shaun Reid
3.			

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (YYYYMMDD) (see note 1) 425	F Start date of employment as an apprentice in the tax year (YYYYMMDD) (see note 2) 430	G End date of employment as an apprentice in the tax year (YYYYMMDD) (see note 3) 435
1.	110955a	2013-04-08	2015-01-01	2015-12-31
2.	PF412	2012-09-04	2015-01-01	2015-12-31
3.				

Note 1: Enter the original registration date of the apprenticeship contract or training agreement in all cases, even when multiple employers employed the apprentice.

Note 2: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the first day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the start date of employment as an apprentice for the tax year in which the government assistance was received.

Note 3: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the last day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the end date of employment as an apprentice for the tax year in which the government assistance was received.

Part 4 – Ontario apprenticeship training tax credit (continued)

	H1 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began before April 24, 2015 (see note 1) 442	H2 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began after April 23, 2015 (see note 1) 443	I Maximum credit amount for the tax year (see note 2) 445
1.	365		10,000
2.	365		10,000
3.			

Note 1: When there are multiple employment periods as an apprentice in the tax year with the corporation, do not include days in which the individual was not employed as an apprentice.
For H1: The days employed as an apprentice must be within 48 months of the registration date provided in column E.
For H2: The days employed as an apprentice must be within 36 months of the registration date provided in column E.

Note 2: Maximum credit = ($10,000 × H1/365*****) or ($5,000 × H2/365*****), whichever applies.
***** 366 days, if the tax year includes February 29

	J1 Eligible expenditures incurred after March 26, 2009 for a qualifying apprenticeship program that began before April 24, 2015 (see note 3) 452	J2 Eligible expenditures incurred for a qualifying apprenticeship program that began after April 23, 2015 (see note 3) 453	K Eligible expenditures **multiplied** by specified percentage (see note 4) 460
1.	49,698		17,394
2.	48,498		16,974
3.			

Note 3: Reduce eligible expenditures by all government assistance, as defined under subsection 89(19) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, in respect of the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.
For J1: Eligible expenditures must be for services provided by the apprentice to the taxpayer during the first 48 months of the apprenticeship program, and not relating to services performed before the apprenticeship program began or after it ended.
For J2: Eligible expenditures must be for services provided by the apprentice to the taxpayer during the first 36 months of the apprenticeship program, and not relating to services performed before the apprenticeship began or after it ended.

Note 4: Calculate the amount in column K as follows:
Column K = (J1 × line 312) or (J2 × line 314), whichever applies.

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5) 480	N ATTC for each apprentice (column L or M, whichever applies) 490
1.	10,000		10,000
2.	10,000		10,000
3.			

Ontario apprenticeship training tax credit (total of amounts in column N) 500 20,000 **O**

Or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount O:

Amount O ______ x percentage on line 170 in Part 1 ______ % = ... ______ **P**

Enter amount O or P, whichever applies, on line 454 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 552, **add** the amounts from line O or P, whichever applies, on all the schedules, and enter the total amount on line 454 of Schedule 5.

Note 5: Include the amount of government assistance repaid in the tax year multiplied by the specified percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the ATTC in that tax year. Complete a **separate entry** for each repayment of government assistance.

See the privacy notice on your return.

Corporate Taxpayer Summary

Corporate information

Corporation's name . . . . Brantford Power Inc.

Taxation Year . . . . 2015-01-01 to 2015-12-31

Jurisdiction . . . . Ontario

BC	AB	SK	MB	ON	QC	NB	NS	NO	PE	NL	XO	YT	NT	NU	OC
				X											

Corporation is associated . . . . Y

Corporation is related . . . . Y

Number of associated corporations . . . 4

Type of corporation . . . . Canadian-Controlled Private Corporation

Total amount due (refund) federal and provincial* . . . . -119,504

* The amounts displayed on lines "Total amount due (refund) federal and provincial" are all listed in the help. Press F1 to consult the context-sensative help.

Summary of federal information

Net income		3,274,219
Taxable income		
Donations		
Calculation of income from an active business carried on in Canada		3,274,219
Dividends paid		1,000,000
Dividends paid – Regular	1,000,000	
Dividends paid – Eligible		
Balance of the low rate income pool at the end of the previous year		
Balance of the low rate income pool at the end of the year		
Balance of the general rate income pool at the end of the previous year		-4,094
Balance of the general rate income pool at the end of the year		-4,094
Part I tax (base amount)		

Credits against part I tax		**Summary of tax**		**Refunds/credits**	
Small business deduction		Part I		ITC refund	
M&P deduction		Part IV		Dividends refund	
Foreign tax credit		Part III.1		Instalments	99,504
Investment tax credits		Other*		Surtax credit	
Abatement/Other*		Provincial or territorial tax		Other*	20,000
				Balance due/refund (–)	-119,504

* The amounts displayed on lines "Other" are all listed in the Help. Press F1 to consult the context-sensitive help.

Summary of federal carryforward/carryback information

Carryforward balances

Investment tax credits	1,317
Non-capital losses that can be carried forward over 20 years	159,164
Cumulative eligible capital	806,800
Financial statement reserve	4,028,110
Other reserves	1,606,069

Summary of provincial information – provincial income tax payable

	Ontario	Québec (CO-17)	Alberta (AT1)
Net income	3,274,219		
Taxable income			
% Allocation	100.00		
Attributed taxable income			
Tax payable before deduction*			
Deductions and credits			
Net tax payable			
Attributed taxable capital	N/A		N/A
Capital tax payable**	N/A		N/A
Total tax payable***			
Instalments and refundable credits	20,000		
Balance due/Refund (-)	-20,000		

Logging tax payable (COZ-1179)

	Ontario	Québec (CO-17)	Alberta (AT1)
Tax payable	N/A		N/A

* For Québec, this includes special taxes.

** For Québec, this includes compensation tax and registration fee.

*** For Ontario, this includes the corporate minimum tax, the Crown royalties' additional tax, the transitional tax debit, the recaptured research and development tax credit and the special additional tax debit on life insurance corporations. The Balance due/Refund is included in the federal Balance due/refund.

Summary of provincial carryforward amounts

Other carryforward amounts

Ontario

Corporate minimum tax credit that can be carried forward over 20 years – Schedule 510 42,763

Summary – taxable capital

Federal

Corporate name	Taxable capital used to calculate the business limit reduction (T2, line 415)	Taxable capital used to calculate the SR&ED expenditure limit for a CCPC (Schedules 31 and 49)	Taxable capital used to calculate line 233 of the T2 return	Taxable capital used to calculate line 234 of the T2 return
Brantford Power Inc.	44,092,266	44,092,266	84,472,036	84,472,036
Brantford Energy Corporation	120,001	120,001		
Brantford Generation Inc				
Brantford Hydro Inc.	4,962,102	4,962,102		
The Corporation of the City of Brantford				
Total	49,174,369	49,174,369	84,472,036	84,472,036

Québec

Corporate name	Paid-up capital used to calculate the Québec business limit reduction (CO-771 and CO-771.1.3) and to calculate the additional deduction for transportation costs of remote manufacturing SMEs (CO-156.TR)	Paid-up capital used to calculate the tax credit for investment (CO-1029.8.36.IN)	Paid-up capital used to calculate the 1 million deduction (CO-1137.A and CO-1137.E)
Total			

Ontario

Corporate name	Specified capital used to calculate the expenditure limit – Ontario innovation tax credit (Schedule 566)
Total	

Other provinces

Corporate name	Capital used to calculate the Newfoundland and Labrador capital deduction on financial institutions (Schedule 306)
Total	

Five-Year Comparative Summary

Federal information (T2)

	Current year	1st prior year	2nd prior year	3rd prior year	4th prior year
Taxation year end	2015-12-31	2014-12-31	2013-12-31	2012-12-31	2011-12-31
Net income	3,274,219	-3,430,783	-371,607		
Taxable income					
Active business income	3,274,219				
Dividends paid	1,000,000	750,000	750,000		
Dividends paid – Regular	1,000,000	750,000	750,000		
Dividends paid – Eligible					
LRIP – end of the previous year					
LRIP – end of the year					
GRIP – end of the previous year	-4,094	-4,094	23,656,147		
GRIP – end of the year	-4,094	-4,094	23,391,250		
Donations			2,600		
Balance due/refund (-)	-119,504	-149,251	-94,146		
Line 996 – Amended tax return	☐	☐	☐	☐	☐

Loss carrybacks requested in prior years to reduce taxable income

Taxation year end	2015-12-31	2014-12-31	2013-12-31	2012-12-31	2011-12-31
Taxable income before loss carrybacks	N/A	N/A			
Non-capital losses	N/A	N/A			
Net capital losses (50%)	N/A	N/A			
Restricted farm losses	N/A	N/A			
Farm losses	N/A	N/A			
Listed personal property losses (50%)	N/A	N/A			
Total loss carried back to prior years	N/A	N/A			
Adjusted taxable income after loss carrybacks	N/A	N/A			

Losses in the current year carried back to previous years to reduce taxable income (according to Schedule 4)

Taxation year end	2015-12-31	2014-12-31	2013-12-31	2012-12-31	2011-12-31
Adjusted taxable income before current year loss carrybacks*	N/A				N/A
Non-capital losses	N/A				N/A
Net capital losses (50%)	N/A				N/A
Restricted farm losses	N/A				N/A
Farm losses	N/A				N/A
Listed personal property losses (50%)	N/A				N/A
Total current year losses carried back to prior years	N/A				N/A
Adjusted taxable income after loss carrybacks	N/A				N/A

* The adjusted taxable income before current year loss carryback takes into account loss carrybacks that were made in prior taxation years.

Loss carrybacks requested in prior years to reduce taxable dividends subject to Part IV tax

Taxation year end	2015-12-31	2014-12-31	2013-12-31	2012-12-31	2011-12-31
Adjusted Part IV tax multiplied by the multiplication factor**, before loss carrybacks	N/A	N/A			
Non-capital losses	N/A	N/A			
Farm losses	N/A	N/A			
Total loss carried back to prior years	N/A	N/A			
Adjusted Part IV tax multiplied by the multiplication factor**, after loss carrybacks	N/A	N/A			

Losses in the current year carried back to previous years to reduce taxable dividends subject to Part IV tax (according to Schedule 4)

Taxation year end	2015-12-31	2014-12-31	2013-12-31	2012-12-31	2011-12-31
Adjusted Part IV tax multiplied by the multiplication factor**, before current-year loss carrybacks***	N/A				N/A
Non-capital losses	N/A				N/A
Farm losses	N/A				N/A
Total current year losses carried back to prior years	N/A				N/A
Adjusted Part IV tax multiplied by the multiplication factor**, after loss carrybacks	N/A				N/A

** The multiplication factor is 3 for dividends received before January 1, 2016, and 100 / 38 1/3 for dividends received after December 31, 2015.

*** The adjusted Part IV tax multiplied by the multiplication factor before current-year loss carrybacks takes into account loss carrybacks that were made in prior taxation years. This amount is multiplied by the multiplication factor to help you determine the loss amount that must be used to reduce Part IV tax payable to zero.

Federal taxes

Taxation year end	2015-12-31	2014-12-31	2013-12-31	2012-12-31	2011-12-31
Part I					
Part IV					
Part III.1					
Other*					

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Credits against part I tax

Taxation year end	2015-12-31	2014-12-31	2013-12-31	2012-12-31	2011-12-31
Small business deduction					
M&P deduction					
Foreign tax credit					
Investment tax credit					
Abatement/other*					

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Refunds/credits

Taxation year end	2015-12-31	2014-12-31	2013-12-31	2012-12-31	2011-12-31
ITC refund					
Dividend refund					
Instalments	99,504	149,251	136,909		
Surtax credit					
Other*	20,000				

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Ontario

Taxation year end	2015-12-31	2014-12-31	2013-12-31	2012-12-31	2011-12-31
Net income	3,274,219	-3,430,783	-371,607		
Taxable income					
% Allocation	100.00	100.00	100.00		
Attributed taxable income					
Surtax					
Income tax payable before deduction					
Income tax deductions /credits					
Net income tax payable					
Taxable capital					
Capital tax payable					
Total tax payable*			42,763		
Instalments and refundable credits	20,000				
Balance due/refund**	-20,000		42,763		

* For taxation years ending before January 1, 2009, this includes the corporate minimum tax and the premium tax. For taxation years ending after December 31, 2008, this includes the corporate minimum tax, the Crown royalties' additional tax, the transitional tax debit, the recaptured research and development tax credit and the special additional tax debit on life insurance corporations.

** For taxation years ending after December 31, 2008, the Balance due/Refund is included in the federal Balance due/refund.

Attachment 4-SEC-18-C.1: FIS

SOLUTION SPECIFICATIONS AND RESPONSE CRITERIA

SECTION 1: PREREQUISITES

BPI has undertaken an effort to streamline processes and systems. This process began through a consultative approach, where internal stakeholders were engaged to perform a System Integration Study to identify opportunities for efficiencies. Through that study, BPI identified the following Guiding Principles:

a) **Productivity:** Integration solutions must generate efficiencies and improve productivity and/or cross functional communications

b) **Security**: integration solutions must ensure security of data and systems

c) **Adaptability:** integrated solutions must be flexible to meet changing business and regulatory requirements

d) **Standards:** integration solutions must adhere to best practices

e) **Performance**: integration solutions must scale to accommodate changes in user or transaction volumes;

f) **Sound Investment:** Integration solutions must balance cost and benefits

BPI endeavours to only select systems or solutions which are consistent with these Guiding Principles. The questions pertaining to the technical solutions and the proponents providing those solutions that are posed through Sections 1, 2 and 3 should result in information that will allow BPI to evaluate the solutions and providers that most closely align with the identified Guiding Principles.

For a technological procurement such as the Financial Information System solution, BPI would stress to proponents that the principles that are especially relevant are the principles which capture the need for:

- Productivity: BPI provides information in Section 3 which enlightens proponents to the current operating environment which is considered less than ideal. Proponents are encouraged to be fulsome in their answers so that the efficiencies provided by their solution are easily recognized and understood by the evaluation team.
- Security: BPI has asked questions in several sections about the role based security that is provided and how the functionality is provided in a manner that is consistent with Security Best Practices.
- Standards: in the context of this software solution RFP, the Standards principle can be perceived to mean that BPI will not look to modify the proposed solution in any way. Rather, BPI will modify their existing business processes so that customization of any proposed solutions is not required. In this way BPI will simplify the testing and ongoing upgrade requirements for any solution that is procured.

Proponents should ensure that the answers to the questions found in the following sections (i.e. Sections 1, 2 and 3) are as comprehensive as possible so that BPI can understand not only the technical capabilities but also how the solution and the solution provider will fulfill the requirements associated with their Guiding Principles.

1.1 Multi-Company

Brantford Energy Corporation (BEC) operates as a holding company for three businesses: Brantford Power Inc., Brantford Hydro Inc., and Brantford Generation Inc. Its sole shareholder is the Corporation of the City of Brantford.

In March 2000, after the Government of Ontario restructured the province's electricity industry, the City of Brantford set up its utilities as commercial enterprises. Brantford Energy Corporation was established as the holding company for its two operating firms.

- Brantford Power Inc. is the local distributor of electricity to homes and businesses in Brantford. It maintains the system and ensures it is safe, reliable and cost-effective.
- Brantford Hydro Inc. is the retail company that provides water heater rentals, sentinel lighting and high-speed fibre optic telecommunication connections through its NetOptiks division.

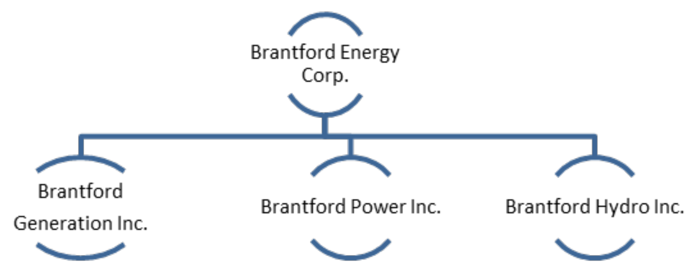


Figure 1: Current BEC Configuration

In 2007, Brantford Energy Corporation incorporated a third operating firm as follows:

- Brantford Generation Inc. is the generation company that currently owns and operates a single Landfill Gas Collection and Utilization Facility.

BPI's financial team operates in a complex multi-company environment, and therefore requires that the proposed solution provides multi-company functionality. BPI will use the proposed solution to manage the financial information of BEC and the operating firms.

i. The proponent should state compliancy with the requirement that its solution is capable of performing accounting functions for a multi-company environment.

ii. Can data in a multi-company scenario be managed as to ensure that only authorized users can access data within specific operating firms?

1.2 Compliance with Ontario Accounting and Reporting Requirements

1.2.1 Use of Accrual Accounting

BPI follows accounting best practices, such as accrual accounting where two sided (balanced) transactions are used to match revenues with expenses that may occur at different points in time. BPI's business is complex in nature, preventing the use of more simplified practices such as cash accounting and account reconciliation within the system. BPI requires that the system is able to operate in this complex environment and provide flexible reporting so that the current financial condition of the company is easily communicated to stakeholders.

i. Proponents should make a statement of compliancy indicating that Accrual Accounting is possible in all of the modules that are provided as part of the solution.

1.2.2 Compliance with GAAP and IFRS standards

All companies within Brantford Energy Corporation are currently transitioning from Generally Accepted Accounting Principles (GAAP) to the International Financial Reporting Standards (IFRS). For electric utilities like BPI, there are significant changes required in the adoption of IFRS, such as the more granular componentization of assets and the implementation of useful lives as well as the differing depreciation schedules based on such parameters as location.

i. Proponents should provide a statement attesting to its ability to adopt the IFRS.

BPI is regulated by the Ontario Energy Board (OEB). The OEB requires electric utilities to report certain aspects of their financial results differently from IFRS.

i. Confirm ability to fulfil these requirements with ease for electric utility companies.

1.2.3 Compliance with Current HST Requirements

Proponents should explain how the proposed solution handles taxes. BPI requires that all modules within the solution are able to accommodate current HST requirements as follow:

i. ability to automate the calculation of Input Tax Credits including any that are restricted

ii. flexibility within the system for handling taxes (i.e., can the system apply multiple taxes concurrently) in the event that the tax structure were to change in Ontario.

SECTION 2: PROPONENT COMPANY INFORMATION

For each question, please provide information (I), a statement of compliancy (C) or both (CI).

2.1 Experience Providing Same or Similar Products (I)

To ensure long-term viability, the selected proponent must be a proven vendor in the area of FIS. The proponent is asked to answer the following questions intended to help BPI evaluate the proponent's experience providing the scope of services included in this RFP.

i. How many years has the proponent been in business?

ii. How long has the proponent been providing the proposed FIS solution?

iii. Proponents should provide a list of **electricity distribution utilities in Ontario** that are using the system. Proponents shall also be specific about which of the listed utilities are using the version proposed.

iv. What is the average size of the utilities using the FIS solution? To demonstrate "size", proponents are asked to discuss their customer in terms of the number of customers serviced by the distribution utility.

v. How long has the solution been deployed and implemented, excluding any period of time for which it was in a beta test status?

vi. How long has the proposed version of the solution been deployed and implemented, excluding any period of time for which it was in a beta test status?

vii. Describe the proponent's primary line of business and the percentage of its business derived from the sale of FIS products and associated services.

viii. What is the current size (number of employees) in the FIS group? Additionally, proponents are asked to provide turnover rates for both the larger company and the FIS group for last three (3) years.

ix. Please provide the number of employees assigned to application development, implementation and support for the FIS product proposed.

x. What is the current financial condition of the proponent's company? The financial conditions for the FIS division within the company? Provide supporting documentation and annual reports for the last three years. If the company is privately held, supply sufficient information to document the company's financial status.

xi. Please provide your corporate roadmap specific to your FIS product and its development within your corporation.

2.2 Contract Manager (I)

The proponent is asked to acknowledge the requirement to designate a Contract Manager who shall have the authority to handle and resolve any technical issues, disputes, or contractual issues in a timely manner. The proponent is asked to describe the Contract Manager's experience with managing projects of a similar size and scope, including timelines, and results (if applicable). The response should include the Contract Manager's and any other related team member's curriculum vitae (CV).

2.3 References (I)

To ensure long-term viability and maintenance of the system, the selected proponent must be a proven vendor in the area of application software.

i. The proponent is requested to provide a list of at least three (3) references (contact names and phone numbers) for local distribution companies using the Proponent's proposed system to perform the same or similar application(s) as the one(s) described in this RFP for the past three (3) years.

ii. The proponent is requested to provide a list of at least three (3) references (contact names and phone numbers) for companies using the proponent's system that has also integrated with a Daffron CIS.

The references for questions 1 and 2 can be the same utilities. The references provided in Section 3.21.2 can also be the same if required.

2.4 Health and Safety (I)

BPI believes in an incident and injury-free work place. We are committed to managing our business in a safe and responsible manner by taking accountability for personal safety. We place no greater importance on what we do above accomplishing it safely.

In every part of our operations, we will:

- Make the safety of our employees, customers, and the public our first priority, regardless of the type of work or the situation.
- Continually improve our safety performance by reporting, analyzing, and taking action based on incident experiences.
- Incorporate safe management principles in all phases of our business including design, operations, and purchasing.
- Proactively comply with safety legislation and regulations in all of the jurisdictions we operate.
- Ensure that our employees and contractors understand the consequences of their actions and have the knowledge and skills to make the right decisions.
- Communicate our goals and progress with regulatory agencies, customers and other stakeholders regarding our performance in relation to those safety targets.

Although the successful proponent will be an independent contractor of BPI's, it is imperative that the proponent puts the same value and importance on environment, health, and safety as has been noted above.

The proponent is to provide data to support its safety record such as corporate safety statistics and internal safety record. In addition, the proponent must provide documentation supporting its commitment to safety within its manufacturing facilities and design of products.

2.5 Litigation (I)

Proponents are required to disclose any anticipated or pending lawsuits or any litigation within the past five (5) years or bankruptcy filings within the past ten (10) years.

2.6 Standard Agreement (I)

The proponent is expected to provide a copy of the standard agreement to the BPI. BPI requests that the proponent provide business terms for software maintenance and support.

2.7 Subcontractors (I)

BPI reserves the right to approve any subcontractors, and therefore BPI requires full disclosure with regards to the intended use of subcontractors. The proponent shall take responsibility for all subcontractors.

In addition to stating compliancy to these requirements, the proponent shall submit a list of subcontractors including name and explanation of the work to be performed by the subcontractor. If there will be no subcontractors, the proponent shall identify that they will not be using subcontractors.

SECTION 3: TECHNICAL SOLUTION

For each question, please provide information (I), a statement of compliancy (C), or both (CI).

3.1 BPI's Current Operating Environment

Brantford Power Inc. (BPI) has been working with the City of Brantford (COB) in a shared services agreement. Under this Service Level Agreement (the "SLA") the COB provides both services, and access to systems and personnel. While the SLA has been mutually beneficial, the ever evolving electricity market has forced BPI to examine the efficiencies that might be found through a more integrated financial system.

At a high level, Proponents should understand that the critical systems in use at BPI are:

- **JDE**: The City of Brantford operates the JDE financial system. BPI has access to certain modules within the system, and there is integration that exists between JDE and other utility systems to allow both the COB and BPI to manage their respective businesses.
- **Daffron**: BPI uses the Daffron CIS for their customer billing process. In addition to customer billing, BPI has secured certain financial system modules, including inventory, staking and estimation (job costing).

At a high level, proponents should understand that under the SLA:

- COB provides AP services to BPI
- COB provides HR and Payroll services to BPI
- COB provides IT services to BPI

3.2 BPI Systems in Use

BPI currently uses the following systems:

- Advanced Metering Infrastructure (AMI): Sensus (Data Collection for TOU Billing)
- Itron MV90 (Data Collection for GS>50 accounts)
- Geographic Information System (GIS): Intergraph (Oracle dbase)
- Supervisory Control and Data Acquisition (SCADA): Survalent
- Engineering Analysis: DESS
- Asset Management: Urban and Environmental Management Inc. (UEM)
- Financial Management: JDE (Enterprise One v9.0, Oracle dbase)
- Outage Management System (OMS): Not in use
- Customer Information System (CIS): Daffron (includes utility billing, work orders (estimation, staking, bill of material), service orders, inventory)
- Workforce Management (WFM): Paper service/work orders
- Payroll Data Entry: TAPS (City of Brantford system, Integrated with JDE for HR/Payroll)
- Web Presentment: Distributech (in deployment)
- Preferred Database: Microsoft SQL
- Preferred Virtualization Application: IBM VMware
- Settlement: Kinetiq

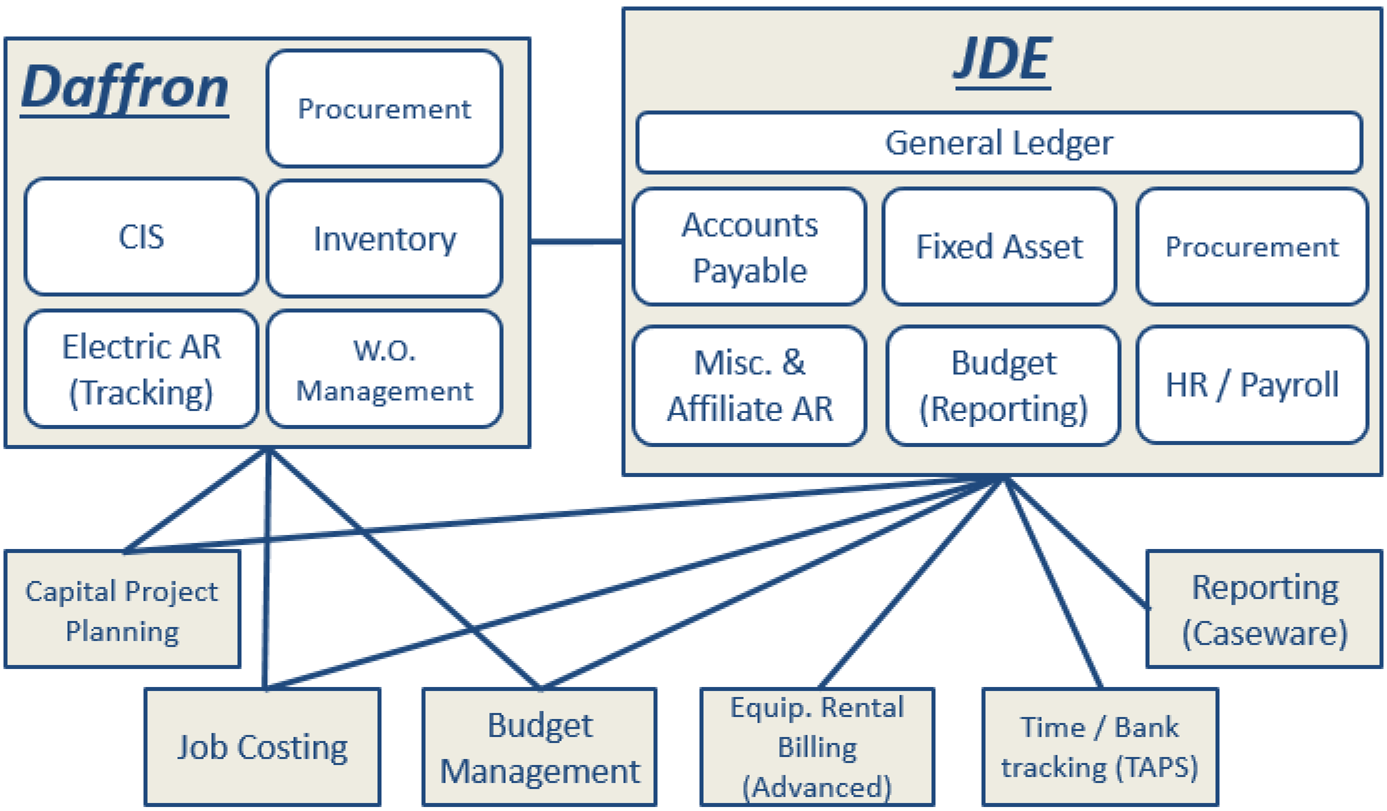
- Business Intelligence: Qlikview / Caseware

BPI's affiliate companies use:

- Customer Relationship Management (CRM): SalesForce.com
- City of Brantford Water Billing System: Advanced (i.e., to accommodate the billing of equipment rentals for Brantford Hydro Inc.)

3.2.1 Current Data Flow

The following diagram is provided to illustrate for proponents how the existing systems are used and which systems house each financial module. As shown, in some cases functions which might form part of an integrated FIS are currently handled outside of a core system requiring integration or some other form of data exchange mechanism.



3.2.2 Expected Data Flow

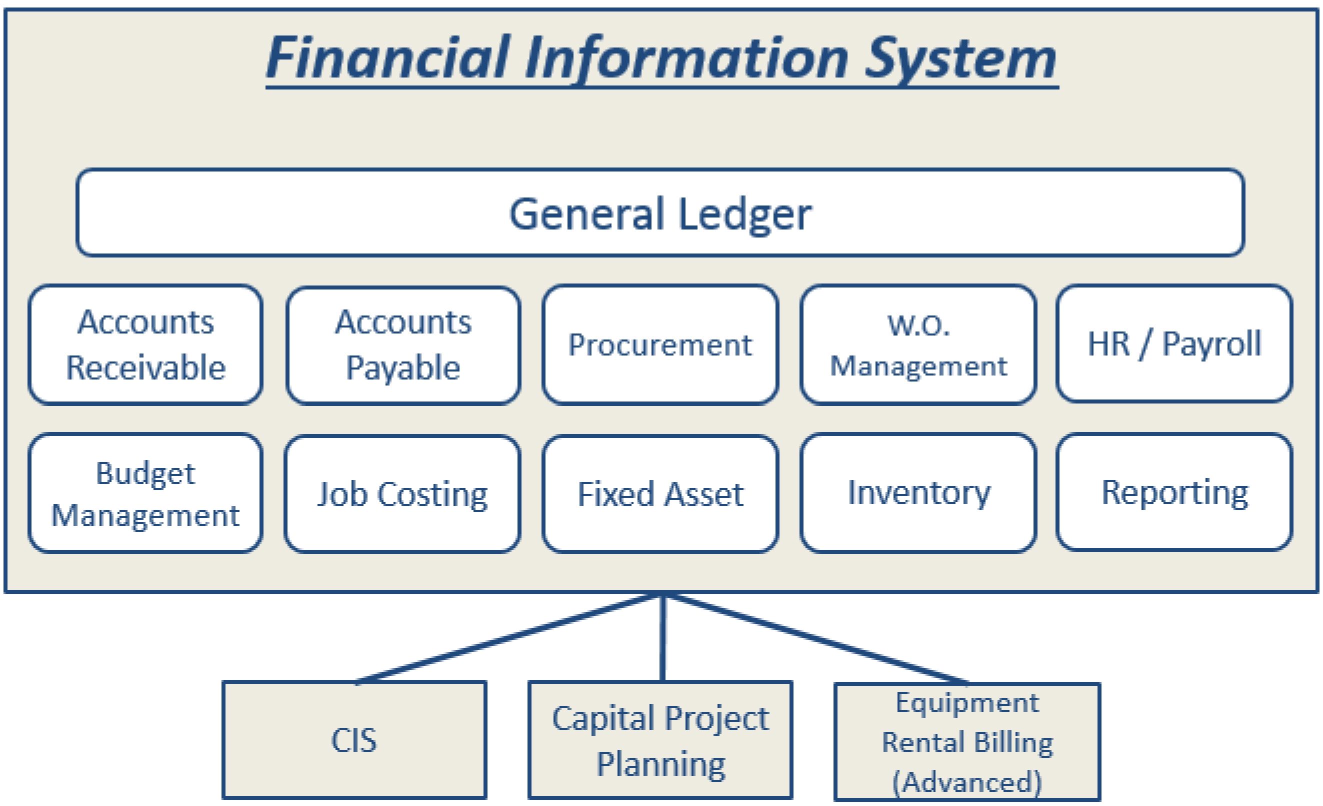
The following diagram is provided to illustrate how an integrated system might streamline the data exchange that is required in the management of BPI's daily business processes.

Proponents should understand that:

- In transitioning to a more integrated FIS, BPI hopes to move to a more standard approach to financial information management. BPI is currently developing an RFP to acquire a Customer Information System (CIS) solution to fulfill the customer billing requirements. It is expected that there would be integration between the proposed FIS and the CIS to communicate the required information between systems. This RFP document requests information regarding the proponent's experience integrating with CIS systems in Section 3.4.2.
- In transitioning to a solution that provides the options for managing Financial Information within a more integrated system, BPI has not precluded the possibility that the existing SLA (as described in Section 3.1) will continue to

offer a financially feasible solution for BPI. To this end, this RFP document requests information from proponent's regarding the following:

- Section 3.13 requests a proponent's experience integrating the proposed solution with external HR/Payroll solutions, in the event that BPI continue using the existing COB solution for these functions with the possibility that BPI migrate to a BPI managed HR/Payroll function at some future time.
- Section 3.12 requests information regarding the functionality of the Fixed Asset module in meeting the evolving requirements for Asset Management, including such Reporting requirements as those captured within "Chapter 5: Consolidated Distribution System Plan" which support the OEB Cost of Service Rate Application process. BPI currently manages these requirements using an external system that is integrated with both JDE and Daffron; BPI would like to understand if the proposed system can optimize this process.
- In light of the fact that IT Services are captured within the existing SLA, BPI has requested information pertaining to the management of data within the hosted model to better understand whether limitations exist in this model.
- Given that HR / Payroll and AP are currently captured within the SLA, BPI has requested a proposed implementation plan that will mitigate the risk associated with the significant Change Management required through the transition of this critical system.



3.3 FIS Hardware Specification (I)

It is important that BPI understand the technical platform that is required for the proposed FIS solution. BPI requires a Service Level Agreement that will be structured around a high availability solution. Proponents are also reminded that BPI's preference is for the hosted model, whereby the proponent will be responsible for support and maintenance of the hardware. Given these requirements, proponents are asked to provide detail regarding the optimal architectural design of the FIS and to distinguish between virtual and physical. At a minimum, the following should be addressed:

- Database in use
- Operating System
- Program language/coding in which the system is written
- Server Specifications
- Third Party Licenses required to run the FIS
- Architectural Diagram
- User licenses included with base product (concurrent and permitted login accounts).

3.3.1 FIS Environments (I)

At minimum, BPI expects that the proposed solution will include:

- Production FIS
- Development FIS
- Test FIS
- Disaster Recovery (DR) FIS

If these environments are not included within the cost of the proposed solution, proponents should provide pricing for these additional environments in the pricing spreadsheet provided with this RFP document.

Proponents should describe their license policy for these multiple environment scenarios and if any functionality or sizing differences exist between the systems. Also, any standard form licensing agreements that may apply should be provided.

Additionally, within the documentation provided, proponents should specifically address the following:

i. Will the test environment be configured as a mirror of the live environment, or will BPI be required to configure different synchronization processes for the test environment?

ii. Will one test environment suffice, or as a result of the proponent's anticipated version/patch release schedule, will multiple test environments be a requirement? If multiple environments are suggested, proponents are reminded to be clear about the licensing impacts in the pricing matrix

iii. In the hosted environment, will the same service levels apply to the test environment as to the live environment?

3.3.2 Scalability of the FIS Solution (I)

It is important to BPI that the solution is scalable to handle not only the existing business requirements, but also potential growth in the future. To demonstrate scalability, proponents should provide information and their experience with the following:

i. What is the largest electrical utility using the proposed solution?

ii. What is the largest organization using the proposed solution?

iii. To what volume of daily transactions has the product been tested?

iv. What are the suggested data retention practices within the product? For example, are transactions older than 10 years moved offline? Or is all data that is entered into the system always available for analysis? NOTE: BPI's standard data retention policy is 7 years; and therefore BPI expects that data is easily accessible for a minimum of 7 years with the possibility for offline access beyond 7 years.

3.3.3 Disaster Recovery of the FIS solution (CI)

Proponents should describe a Best Practice FIS Backup plan. The proponent is asked to indicate if the proposed system is capable of running as a two server configuration with a primary and secondary server. If so please describe the fail over procedure. If the system runs as a single server, is it possible to failover to test and then fail back?

BPI expects that the FIS will provide high availability (i.e., 99.99% uptime). Proponents should acknowledge that the solution is high availability, and what the performance remedies are, should the proponent fail to meet this Service Level Agreement.

The proponent is to provide its standard service level agreements and remedies for failure to meet those SLAs. Sample reports should be provided to show how the proponent tracks, monitors and measures the service levels as well as key performance indicators.

3.3.4 BPI's CIS Procurement (I)

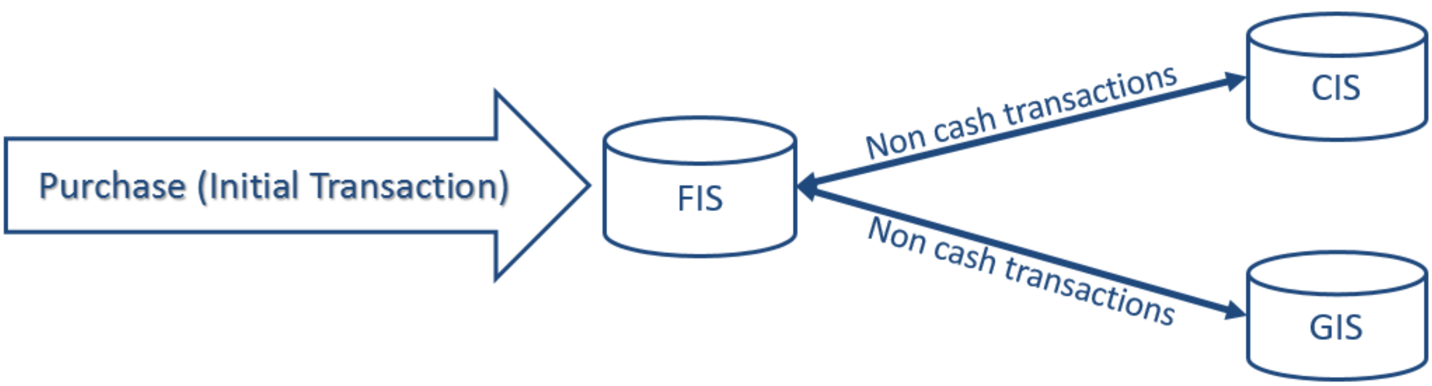
BPI is in the process of developing a CIS RFP. Proponents should explain whether the platform on which the FIS is built will allow possible future synergies. For example, if BPI were to purchase a solution (or elect for a hosted solution) that ran the same database, would it be possible to share hardware or reduce the costs associated with licenses?

3.4 Integration of the FIS

BPI's vision for integration of the FIS includes the following concepts:

- FIS will be the ***system of record*** for financial transactions leading to or resulting from cash inflows or outflows
- GIS is the ***system of record*** for geospatial information; including information associated with the installation and removal of assets (e.g., transformers)
- CIS is the ***system of record*** for all customer transactions including customer related billings and payments.

BPI's goal for the future integration of the FIS with other utility systems is that data entry will occur only once; downstream systems will be updated through the integration between systems.



3.4.1 Integration with the GIS (CI)

BPI's motivation to integrate the proposed FIS with their GIS includes the componentization of assets such as transformers, and the depreciation of assets according to IFRS requirements within the FIS. GIS will understand the physical location of assets, and the dates which assets were installed or removed from the field. To prevent data entry from being required in multiple systems, BPI will look to integrate the FIS and GIS to exchange the relevant information.

Proponents should include a statement of compliancy that their system is capable of being integrated with GIS systems for the purpose of communicating asset information between FIS and GIS. In addition to this compliancy statement, proponents should describe their experience creating integration between FIS and GIS, specifically addressing:

i. What GIS systems have been integrated with the proposed FIS solution?

ii. What pieces of information are typically exchanged between these critical utility systems?

iii. Do standard interfaces (e.g., MultiSpeak) exist that can simplify the process to integrate the proposed solution with BPI's GIS?

iv. Given that the current GIS database is Oracle, proponents should explain how their system integrates with the Oracle database and whether there are any concerns that should be noted or cost implications.

3.4.2 Integration with the CIS (CI)

BPI's motivation to integrate the proposed FIS with their CIS includes improved FIS reporting on customer billings, and the forecasting of consumption and the analysis of the impacts of forecasts on the financial standing of the organization. In the process to componentize assets such as meters, and in the depreciation of assets according to IFRS requirements within the FIS, CIS will understand the physical location of assets, and the dates which assets were installed or removed from the field. To prevent data entry from being required in multiple systems, BPI will look to integrate the FIS and CIS to exchange the relevant information.

Proponents should include a statement of compliancy that their system is capable of being integrated with CIS systems for the purpose of communicating billing statistics information between CIS and FIS, as well as asset information. In addition to this compliancy statement, proponents should describe their experience creating integration between FIS and CIS, specifically addressing:

Proponents should describe their experience creating integration between FIS and CIS, specifically addressing:

i. What CIS systems have been integrated with the proposed FIS solution?

ii. What pieces of information are typically exchanged between these critical utility systems? Proponents are reminded that BPI will require CIS integration to accommodate the following:

    a. BPI will exchange meter inventory information between FIS and CIS

    b. BPI will exchange electric billing statistical information between CIS and FIS (i.e., including refunds, credits, consumption and demand data, etc.)

    c. BPI will receive equipment rental billing statistical information from COB CIS

iii. Do standard interfaces (e.g., Web services) exist that can simplify the process to integrate the proposed solution with BPI's CIS?

iv. Proponents are reminded that BPI will require two integrations to CIS; one to support the implementation of the new FIS, and a second effort will be required upon implementation of the new CIS (i.e., as explained in Section 3.2.1, BPI is currently involved in a CIS procurement process). Proponents should describe their experience with utilities that have made changes to their critical systems, requiring the development and testing of new interfaces, and the cost impacts that this may have given that the two processes may be conducted within the first few years of deployment.

3.4.3 Integration to Other Utility Systems (I)

Sections 3.4.1 and 3.4.2 capture what BPI perceive to be industry standard best practices for integration. At minimum, BPI will require integration between FIS and both GIS and CIS for the reasons cited in those sections. This is not meant to imply that those will be the only integrations with FIS. BPI currently exchange data between FIS and many other systems external to the FIS as illustrated in Section 3.2.1. Proponents should explain the flexibility within the FIS to integrate with other utility systems, specifically addressing:

i. What is the preferred method of integration between the FIS and other downstream systems? (i.e., SOA, SOAP, API, file based, etc.)?

ii. Within the pricing spreadsheet provided with this RFP, proponents should provide an estimate to interface with the Intergraph GIS and the Daffron CIS.

iii. Does the proponent have experience interfacing with an Enterprise Services Bus (ESB)? If so, proponents should indicate whether the tool has previously impacted—in a positive way—their integration efforts.

3.5 Modules (I)

BPI is moving from a unique environment insofar as it currently operates under a service level agreement with the City of Brantford wherein BPI and the City share responsibility of the utility's financial related services. Currently, the City of Brantford uses the JDE financial system to provide human resources, payroll, accounts payable, and procurement. BPI manages the remainder of its financial services by using its internal Daffron financial system, the City of Brantford's JDE system, and other means (e.g., Microsoft Excel). The breakdown of which system BPI uses to manage each service is as follows:

Daffron	JDE	Other
• Inventory • Customer Billing • Accounts Receivable (Tracking) • Work Order Management • Procurement	• General Ledger • Fixed Asset • Accounts Receivable (Invoicing) • Budget (Reporting)	• Budget Management • Job Costing • Capital Project Planning

As BPI currently operates multiple systems, there may be overlap and/or gaps in processes and technologies, and there may be more efficient ways for the utility to complete its financial functions. Consequently, BPI is interested in moving all financial transactions into an FIS so it can manage processes through a single system that shares data between modules and updates the general ledger seamlessly, minimizing data entry requirements. Operating a single system will allow the utility to realize efficiencies through business process optimization. We would like to understand which modules come standard with the FIS and the costs associated with additional modules.

Proponents should detail which of the following modules are included in the standard offering and/or whether any modules are not available:

- Payroll and Human Resource Management
- Accounts Payable
- General Ledger
- Fixed Asset
- Inventory
- Customer Billing
- Cash Management
- Accounts Receivable
- Work Order Management
- Procurement
- Budget Management
- Job Costing
- Capital Project Planning

3.6 Data Management (I)

BPI embraces Best Practices for data management to the extent possible. Within and across any of the modules in use, when errors are made, or problems encountered, Best Practice business processes are expected to be followed to implement solutions. To that end, proponents are requested to explain how their system handles the following scenarios:

i. Is it a requirement that data be purged from the system at some point? If so, what drives the requirements (i.e. term or data storage or system performance)? If data is eventually purged, what is the process to purge data from the system?

ii. If erroneous data is found, does the system require that it is handled through transactions (i.e., to reverse the problematic entries and resubmit the correct ones) or can records be deleted?

iii. How are changes tracked within the system? Is there an audit trail based on security privileges?

iv. Does the system allow data to be imported from Excel or exported to Excel for exchange with other BPI departments? If so, a description of the process should be provided.

v. Will the system allow adjustments to budgets and encumbrance balances through the use of journal entries? If so, a description of the process should be provided.

vi. Can electronic files be attached to transactions or asset records? If so, a description of the process should be provided.

vii. Explain how entries in the various modules in different currencies are handled by the GL.

viii. How can users search for data within the system across the different modules?

ix. When is the database updated, and when does the data become available for reporting (i.e., at the completion of a transaction, or the posting of a batch, or based on scheduled services/tasks)?

3.6.1 Statistics Ledger (I)

Currently, BPI manages the statistics associated with the OEB Reporting and Record keeping Requirements (RRR) in multiple spreadsheets. Proponents should describe the proposed solution's ability to manage these requirements within the system, specifically addressing:

i. Is there a statistics ledger provided as a separate module or as part of the General Ledger? If as a separate module, the costs for this module should be provided as part of the spreadsheet completed as part of Appendix C – Pricing Form (Schedule of Prices).

ii. Proponents should explain any workflow provided as part of the solution that allows the statistics ledger to simplify BPI's RRR requirements.

3.6.2 Data Conversion (I)

As explained in Section 3.1 and 3.2, BPI's procurement of an FIS solution will result in significant change to the existing procedures associated with financial information management. To mitigate the risk associated with these changes, BPI is interested in learning more about the proponent's ability to plan and manage the required data conversion. For example:

i. Does the proponent provide any tools available which will simplify, expedite, or ensure the data integrity of the required conversion process, during which BPI will move data from legacy systems into the new FIS system?

ii. Does the proponent provide any tools or advocate for any processes which will simplify the testing required during this conversion process?

iii. In the proponent's experience, how much historical data is managed during the conversion and brought forward into the new FIS? Are there cost impacts to the quantity of historical data that is converted into the new FIS?

iv. Based on the experience of the proponent, BPI would request a proposed implementation plan, that captures expected timelines, the order of implementation of modules, and incorporates any relevant information that was presented in subsections i), ii), and iii) of this Section 3.4.1. Proponents should indicate as part of their plan, the BPI resourcing requirements (by resource skill set and person days) that are assumed within the plan.

3.6.3 System Acceptance Test Plan (I)

The purpose of a System Acceptance Test (SAT) will be to verify that the FIS, as configured, is capable of operating at the performance levels required under contract and that the functionality identified in the proponents proposal is operational. SAT should demonstrate the operation of each proposed or required feature, function, and interface in a live environment. SAT will occur upon implementation of the FIS and when the integration with the back office systems has occurred.

Based on the experience of the proponent, BPI would request a proposed SAT plan (that includes system acceptance tests) as well as some indication of the expected time commitment for SAT and a sample responsibility matrix that demonstrates the accountability for performing the tests and documenting results.

3.7 Security

BPI's expectation of any system is to secure the data and database from any malicious behaviour such as unauthorized users performing any Data Definition Language (DDL) operations (i.e., Create, Drop and Alter tables, Creating Stored Procedure to circumvent security, etc.). It is important to BPI that security is a key factor in the initial design of the FIS.

To that end, proponents should explain how the proposed solution addresses:

- Confidentiality and privacy of data
- Controls for malicious code detection, spam protection and intrusion detection
- User authentication and user role controls
- Audit controls and logging of user actions and events

3.7.1 Security Audits (C)

The proponent is expected to perform independent, third party security audits of all its products (of all proponent products commercially available, not just those installed at BPI) annually at their own cost and provide the audit results to BPI or its agents.

The proponent is asked to confirm that its system can be set up to comply with all the above requirements and provide details on how this can be facilitated within the system.

3.7.2 Security Administration (CI)

BPI's evaluation of this FIS RFP will be based upon the hosted model. BPI shall own all data that resides within the FIS. Data stored by the system shall reside in Canada and not be used for any purpose without the approval of BPI. Proponents should acknowledge this requirement and provide an overview of their hosting experience, and the location at which the hardware will be hosted.

Additionally, BPI would like to understand how the security inherent to the system is administered. Proponents should specifically address:

i. Does the proposed solution provide flexibility in the way that security is applied within the system, and across the many processes that are completed using the system? For example, is security applied at the module level, at the menu level, at the transaction level or through the master file configuration? If there is flexibility in the system that allows security to be administered in multiple ways depending on the process, please explain the flexibility and how it is administered.

ii. What is done at the hardware level vs. software?

iii. In the hosted model, who typically performs the security administration? If there are additional costs to administer security, proponents should address this in the pricing matrix.

iv. Can the system temporarily restrict access to any/all users except administrators?

3.7.3 Privacy of Information (CI)

Protection of our customer's personal information is very important to BPI and we require the successful proponent to be in compliance with the Personal Information Protection and Electronic Documents Act (PIPEDA).

The proponent is asked to acknowledge this requirement and to provide a copy of its privacy policies and any other descriptions and documentation showing how the proponent collects, uses, discloses, secures, and retains personal information.

3.8 Reporting (I)

BPI expects that the FIS will provide a flexible and configurable reporting engine, meeting standard requirements (i.e. through "canned reports") but is also able to meet the evolving requirements of the industry without having to incur significant costs when new data "views" are required (i.e., through ad hoc reporting). BPI's vision for the FIS is that it provides a holistic and updated status of the financial condition of the organization, and that the Executive Management team, Directors, Managers and Supervisors will all have access to reports which will assist them in managing their daily functions, and provide insight into their departmental projects and goals.

i. Proponents are requested to provide an overview of the reporting engine and a description of how the reporting engine accesses information from the different FIS modules.

ii. What sort of reporting is available to illustrate historical trending?

iii. What sort of reporting formats are available? Is it possible to graphically display information? Proponents should provide samples to illustrate the flexibility of the reporting engine.

iv. Is it necessary that reports are run from within individual modules, or is there a reporting function in the General Ledger that accesses all underlying modules?

v. How does the proponent manage evolving regulatory requirements for their Ontario client base?

vi. With regards to reporting, how is a pending transaction handled? For example, when do reports get updated for a vendor invoice; at the completion of a staff journal entry, or single inventory issue?

vii. How do the inquiry screens and reports deal with nil records (i.e. are records skipped, or filled with 0's)?

viii. With regards to reports, what is the impact of security? If reports are generated by someone without the security clearance to view all of the applicable data, how does the system present the report? If the request was for onscreen reports as opposed to hard copy, does the system handle the issue differently?

3.8.1 Canned Reports (I)

BPI expects that certain reports will come standard with the system. It is expected that the system will allow reports to be created across varying time periods and with comparative data, and that there should be options for report format such as graphical.

i. Proponents should provide a listing of the standard reports available within the system, and the level of configurability within the reports. For each report, please confirm that the report is considered part of the core system, how it can be accessed (e.g., online access) and provide screenshots of the reporting user interface and sample reports.

ii. Does the system provide templates that can be customized? Will the system allow a BPI user to create new templates? Proponents should provide a list of templates and samples of the templates.

3.8.2 Ad Hoc Reports (I)

BPI expects that the FIS will provide more advanced reporting capabilities than just the standard or canned reports listed in the previous section.

Some examples of ad hoc reporting might include the ability to:

- Group accounts on a user defined basis to satisfy multiple reporting requirements
- Drill down from on screen reports to see source data/transactions
- View pending journal entries without posting
- Create customizable budget variance reports
- Analyze historical trends

As with canned reports, BPI expects that the system will allow reports to be created across varying time periods and with comparative data, and that there should be options for report format such as graphical.

i. Proponents are requested to provide an overview of how their ad hoc reporting tools function, citing several examples of how data can be queried and viewed in the system. If the examples provided are achievable, provide screenshots to demonstrate the ability of the system to provide this flexibility.

3.9 Business Intelligence

BPI expects that the proposed FIS solution will provide an improved ability to discern the near real time financial status of the organization. For example, based on integration with CIS combined with the information managed within the FIS modules, the business intelligence capabilities should allow a dashboard view of the actual as well as forecasted cash flow. Depending on a user's department and security levels, other mission critical information that might be viewed in near real time could include the status of important inventory items such as transformers, the status of payroll jobs, the status of purchase orders and inventory receipt, etc.

Through the following questions BPI hopes to gain a better understanding of the business intelligence capabilities within the system.

3.9.1 Analytics and Dashboard Reporting (I)

BPI's vision for the FIS is that multiple resources across the organization will utilize the FIS to better understand the real time status of their department budget, or that of an ongoing project.

Proponents should explain in detail the flexibility that is available within the system to perform analytics, or to create a customized dashboard or summary view based on user login. Some examples of dashboard concepts might include:

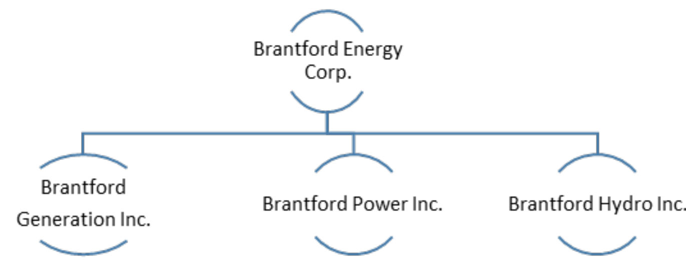
- Summary view of the budget for the appropriate business unit
- Summary view of the jobs in progress and the status of each, as well as financial information such as the job budget
- Lists of requisitions that require sign-off
- Status of payroll timesheets
- As applicable, exception reporting, with the ability for the user to "drill into" the details

- Executive views which further “roll up” data to a team level, showing (for example) budget information for the business unit to which the user belongs
- Rolling capital, and revenue and expense forecasts, and year end trajectory
- Cash flow forecasts based on customer/vendor due dates based on the detail contained within the modules

Information provided by the proponent should not be restricted to the examples listed, rather, the proponent should be comprehensive in their description of the dashboard functionality and the configurability of this important reporting tool.

3.9.2 Consolidated Reporting (I)

The Brantford Power Inc. finance team provides accounting services to all of the Brantford Energy Corporation’s affiliate companies.



Currently financial management is performed in a single system, but consolidated reporting is provided using an external system with integration into the existing FIS in order to achieve the reporting requirements. BPI envisions the proposed solution’s flexible reporting engine will eliminate the need for this process, by providing all of the required reporting tools within the FIS.

Proponents should provide details around the system's ability to provide consolidated reporting. If possible, screenshots to illustrate the look and feel of the system should be provided, which will help BPI to understand the ease with which an authorized user can navigate between companies while managing financial information.

3.9.2.1 Multi-Company Configuration (I)

Proponents should indicate if there are any limitations to the number of companies that can be configured within the proposed solution, and how the solution maps the relationship between companies to allow consolidation. In their responses, proponents should address how “parent-child” relationships are created and managed by the system to allow the multi-company configuration to function.

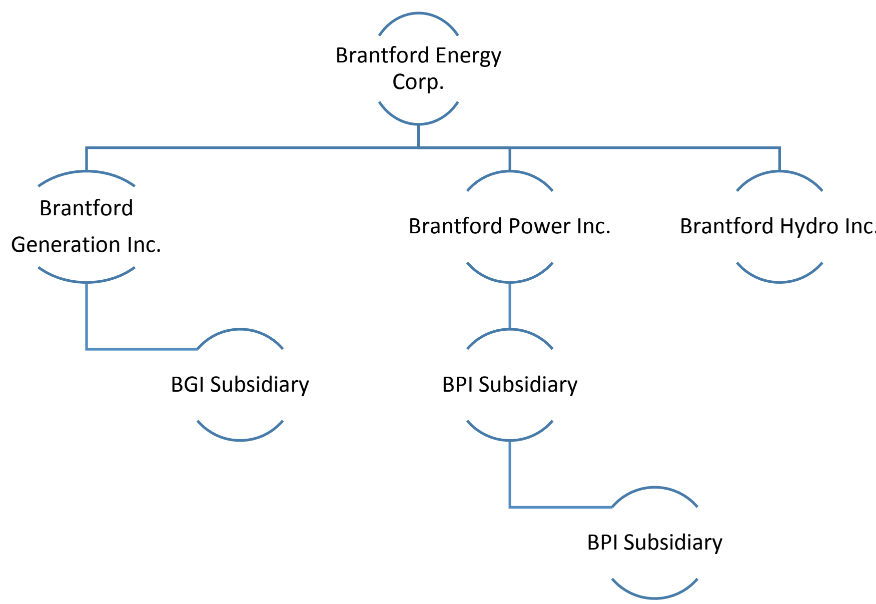


Figure 2: Possible future configuration

3.10 Workflow Automation (I)

BPI is interested in understanding if there are Workflow Automation capabilities available in the FIS product. Proponents should provide details associated with any Workflow Automation functionality that is currently available within the FIS solution.

i. Does the proposed solution provide workflow functionality to automate business processes within the system that can be controlled and managed by a trained end-user? If yes, does the workflow include routing based on roles defined in the system and assigned to each user and rules determining how a process is handled and works consistently across all module areas and user interfaces within the application?

ii. Does the proposed solution include the ability to scan source documents (e.g., invoices, inventory, journal entries, AR adjustments, etc.) and route through workflow to the appropriate departments for review and approval with appropriate controls and security established?

iii. Does the proposed solution include the ability to request/approve budget adjustments online through the workflow engine? How many levels of approval are possible?

iv. Does the proposed solution provide the same workflow rules/engine regardless of the user interface that is used (i.e., web based vs. client-based interface)?

v. Does the proposed solution provide workflow functionality that allows a user to forward workflow items for a user-designated period of time to another user who will act as a surrogate in being able to review, approve and reject all workflow items in the first user's absence?

vi. Does the proposed solution provide the ability to provide workflow functionality that allows for items to be put into workflow with a combination of parallel or sequential approvals?

vii. Does the proposed solution provide workflow functionality that allows for notification of the results of a workflow step to be sent to a user via email or be viewable internally within the application? Is the type of notification (email or internal to application) customizable for each individual user?

viii. Does the proposed solution provide workflow functionality that allows for users receiving workflow updates via email to click on a link provided within the email that takes the user to the appropriate area within the application to perform the next steps on that workflow?

ix. Does the proposed solution include the ability for online approval of AP? If yes, will the system email supervisors to approve payments according to a configured workflow? Is there workflow to move a closed PO to AP automatically? Is there workflow to assist a user in the matching of AP to invoices?

x. Does the proposed solution include the ability for online approval of account reconciliations? If yes, will the system email supervisors to approve reconciliations according to a configured workflow? Is there the ability to set schedules for reconciliations and report past due items?

xi. Does the proposed solution include the ability to electronically route reminders and track when performance evaluations are due/overdue? Does the proposed solution include the ability to create workflows for employee requests for leave (OT, leave, on-call) including type, total hours, purpose and approvals?

xii. Does the proposed solution allow a user to setup customized views (e.g., common menu selections) or “favourites” which act as shortcuts to navigate the system?

3.11 General Ledger (I)

As part of the larger FIS, the General Ledger (GL) is considered by BPI to be a core component of the system.

Proponents should provide an overview of the General Ledger and any workflow capabilities that may exist. Screenshots to illustrate the look and feel of the system should be provided, which will help BPI to understand the ease with which an authorized user can navigate within the GL to complete daily functions.

3.11.1 Posting to the General Ledger (I)

BPI would like to understand how the proposed solution’s General Ledger and Subsidiary Ledgers work together. Proponents should explain how entries in the various modules are handled with respect to:

i. Posting to previous periods when required.

ii. Posting entries from the various modules (or subsidiary ledgers) in real time and how the system ensures that modules remain balanced with respect to control accounts in the General Ledger.

3.11.2 Chart of Accounts (I)

BPI expects that the FIS will provide a user-friendly interface for the manual entry of accounts. Proponents should provide a description of the process by which the utility user will create accounts, and whether there exists the ability to import lists of accounts in bulk, or restrictions in the way that the system allows access to the accounts. In their description, proponents should address such topics as:

i. The Account Numbering structure

ii. How the system handles accounts when projects persist across multiple years

iii. If the system allows accounts to be grouped to satisfy multiple reporting requirements

iv. If the system allows statistical data to be attached to accounts

v. Flexibility in re-numbering accounts

vi. Flexibility in adding new accounts “on-the-fly” to reflect the current needs of the business unit

vii. In the event that the system allows flexibility to add new accounts “on-the-fly”, Proponents should describe the workflow to create the new accounts and what controls or approvals are built into the system to allow the functionality

viii. Reporting departmentally (e.g., Finance, Engineering, Operations, Regulatory, etc.)

ix. Reporting based on the nature of the expense

x. Functional areas (i.e., OM&A, Billing and Collection, General Administration, etc.) within the COA

xi. Multi-company impacts (with regards to how the COA is setup)

xii. With regards to the setup of the COA, proponents should explain whether a subset of the COA can be created, and whether role based security can be applied so that BPI could conceivably restrict access to specific entities and/or individuals within the group.

3.11.3 Journal Entry and Batch Processing (I)

BPI expects that the system will provide a user friendly interface for processing journal entries, and initiating the batch processing of transactions. Proponents should provide an overview of the process, and screen shots to illustrate the user interface. In their description, proponents should address such details as:

i. Will the system allow users to import journal entries from a spreadsheet format or other application? Are imported transactions validated using the same business rules as other entries made within the system?

ii. Will the system create an audit trail for all transactions, including entries that have been reversed or voided?

iii. Will the system allow journal entries to be altered after posting? If so, what audit trail exists?

iv. Will the system allow journal entries to be entered by departments and routed through workflow for approval?

v. Will the system post journal entries in real-time and make the information available for reporting?

vi. Will the system record the source transaction of the journal entry, whether entered manually or through another module?

vii. Will the system validate journal entries against the chart of accounts structure?

viii. Will the journal entries include budget check or cash availability check and ensure entries balance?

ix. Will the system provide templates and notifications for recurring journal entries, including recurring entries with the same dollar value or varying dollar values and for recurring entries occurring at regular frequencies where the user can set the start and stop dates?

3.11.4 Period Closing and Year End (I)

BPI expects that the system will provide a user friendly interface and process for conducting the period end, and year end closing processes. Proponents should provide an overview of the process, and screenshots to illustrate the user interface. In their description, proponents should address such details as:

i. Does the system accommodate hard and soft period end closings across modules?

ii. Will the system allow a user to re-open a closed period multiple times with appropriate approvals and security?

iii. Will the system support year-end processing at any point in time, as well as multiple times, after the end of the fiscal year?

iv. Will the system close encumbrances by either closing all or selected amounts? If actual expenditure differs from encumbered amount, how does the system handle the discrepancy?

v. Will the system allow reporting for aged outstanding AP and AR as of the period end date? Can these reports be reported at a later date for a previous period end?

3.11.5 Cost Allocation (I)

BPI expects that the system will provide cost allocation functionality. Proponents should explain the capabilities of the proposed solution by providing an overview of relevant processes, and screen shots to illustrate the user interface. In their description, proponents should address such details as:

i. Will the system upload cost allocation data from external systems?

ii. Will the system allocate payroll benefits based on prior year payroll (department as a % of LDC)?

iii. Does the system provide the ability to auto-calculate differences and book clearing account entries for clearing accounts and regulatory accounting Deferral and Variance Accounts (DVAs)?

iv. Will the system allocate costs based on various allocation drivers (e.g., square footage, staffing levels)? Will the system allocate costs based on different periods (i.e., current period vs. year to date)?

v. Will the system allocate costs based on balances in other general ledger accounts?

vi. Will the system assign overhead percentages or burdens on items with an automated true up process to clear any residual balances?

vii. Will the costs being allocated remain in the trial balance with a contra account for the amounts allocated, or do the source accounts become zeroed out?

viii. Will the system allow tiered or multi-step allocations?

ix. Will the system calculate and record interest revenue or expense to the Deferral and Variance Accounts (DVA) based on monthly opening balances using the OEB approved prescribed interest rates?

x. Can the cost allocation process be initiated at user defined intervals?

3.12 Accounts Payable Module (I)

Proponents should provide an overview of the Accounts Payable (AP) module, providing an overview of how the module works, the workflow capabilities that exist within the module, how the module integrates with the GL and other FIS modules, the reporting functions that exist specific to the AP module, and a description of the configurability of the AP Master File.

Screenshots to illustrate the look and feel of the system should be provided, which will help BPI to understand the ease with which an authorized user can navigate within the AR module to complete daily functions.

In addition to the overview of the AP module, proponents are asked to specifically address:

i. What methods of payment are supported within the proposed solution (i.e., cheque vs EFT)?

ii. What flexibility is provided within the proposed solution with regards to payment terms? Are users (with appropriate security) able to override the controls?

iii. Does the proposed solution provide the ability to reflect auto recurring transactions (e.g., rent payments)?

iv. Does the proposed solution provide the ability to hold or expedite payments?

v. Does the proposed solution allow users to email issuance of remittance advices?

vi. Does the proposed solution provide vendor type analysis and purchase analytics?

vii. Does the proposed solution allow integration with purchasing for receipt of goods or services matching?

3.12.1 Master File Setup (I)

With regards to the setup of the master file, Proponents should explain whether a subset of the master file can be created, and whether role based security can be applied so that BPI could conceivably create access profiles so that only authorized users can manage workflow for certain vendors.

3.13 Accounts Receivable Module (I)

Proponents should provide an overview of the Accounts Receivable (AR) module, providing an overview of how the module works, the workflow capabilities that exist within the module, how the module integrates with the GL and other FIS modules, the reporting functions that exist specific to the AR module, and a description of the configurability of the AR Master File.

Screenshots to illustrate the look and feel of the system should be provided, which will help BPI to understand the ease with which an authorized user can navigate within the AR module to complete daily functions.

In addition to the overview of the AR module, proponents are asked to specifically address:

i. What methods of payment are supported within the proposed solution (e.g., cheque, EFT, PAP, etc.)?

ii. What flexibility is provided within the proposed solution with regards to payment terms? Are users (with appropriate security) able to override the controls?

iii. Does the proposed solution provide the ability to reflect auto recurring transactions (e.g., rent payments, fibre billings)?

iv. Does the proposed solution allow users to email invoices?

v. Does the proposed solution provide financing options or payment arrangements?

3.13.1 Master File Setup (I)

With regards to the setup of the master file, proponents should explain whether a subset of the master file can be created, and whether role based security can be applied so that BPI could conceivably restrict access to certain billing customers should the billing processes in the affiliate companies require that ability.

3.14 Cash Management Module (I)

Proponents should provide an overview of the Cash Management module, providing an overview of how the module works, the workflow capabilities that exist within the module, how the module integrates with the GL and other FIS modules, and the reporting functions that exist specific to the Cash Management module.

Screenshots to illustrate the look and feel of the system should be provided, which will help BPI to understand the ease with which an authorized user can navigate within the Cash Management module to complete daily functions.

In addition to the overview of Cash Management, Proponents are asked to specifically address:

i. Does the system allow the import of daily bank activity and balances, and reconcile to recorded receipts and disbursements? Proponents should clearly explain how the system matches detailed FIS transactions that are summarized in the bank.

ii. Does the system generate alerts when insufficient funds are available for planned check runs based on multiple user-defined thresholds?

iii. Are users able to generate receipts offsite using the proposed solution? If not, Proponents should describe their experiences working with third party suppliers of Point of Sale systems which BPI might use in the future to streamline their process.

iv. Does the system provide any Point of Sale functionality or integration to a system external to the core FIS?

3.15 Human Resources and Payroll Module (I)

Proponents should provide an overview of the Human Resources (HR) and Payroll module, providing an overview of how the module works, the workflow capabilities that exist within the module, how the module integrates with the GL and other FIS modules, and the reporting functions that exist specific to the HR and Payroll module. Proponents are requested to provide screen shots to illustrate the look and feel of the system, and which will help BPI to understand the ease with which an authorized user can navigate within the HR and Payroll module to complete daily functions.

In addition to the overview, proponents are asked to specifically address:

i. Within the proposed solution, can HR and Payroll be used independently of each other?

ii. Does the system have the capability or is it integrated with the HR module to 3rd party payroll providers like Ceridian or ADP?

iii. How does the proposed solution handle time and attendance tracking?

iv. Does the proposed solution provide BPI the flexibility to manage multiple union/employee groups?

v. Does the proposed solution provide BPI the flexibility to manage concurrently differing pay period lengths, frequency and pay dates?

vi. Does the proposed solution allow for comprehensive stub period accrual, allowing for accruals to be based on earnings code/ benefit code or field level segregated for employee and employer portions where applicable?

vii. Which statutory reporting obligations will the proposed solution support (e.g., WSIB, Pay Equity, Garnishments, etc.)?

viii. Will the system accommodate flexible or menu driven plans (i.e., where employees select how benefits dollars are allocated)?

ix. Given that the COB currently provides HR and Payroll services under the existing SLA, it would also benefit BPI to understand the ease with which the proposed solution can integrate to third party systems or outsourced service providers which might perform HR and Payroll management on behalf of BPI. Proponents are asked to provide information regarding their experience in this regard, and to also provide insight into how the outsourcing of HR and Payroll management might impact the deployment of the proposed solution for BPI.

3.15.1 Master File Setup

3.15.1.1 Employee Group Setup (I)

With regards to the setup of the master file, Proponents should explain whether a subset of the master file can be created, and whether role based security can be applied so that BPI could conceivably segregate Executive, Non-Union and Union payrolls based on master file profile.

3.15.1.2 Individual Employee Setup (I)

With regards to the setup of the master file, Proponents should explain whether a subset of the master file can be created, and whether role based security can be applied so that BPI could conceivably create a work order for each employee. These work orders would capture information unrelated to field work, and would need to be managed using security so that field staff would not have the ability to view these work orders. If so, will the system provide the ability to interface (transfer) the resulting financial amounts to the work orders and GL at the employee level of detail (with the appropriate level of security)?

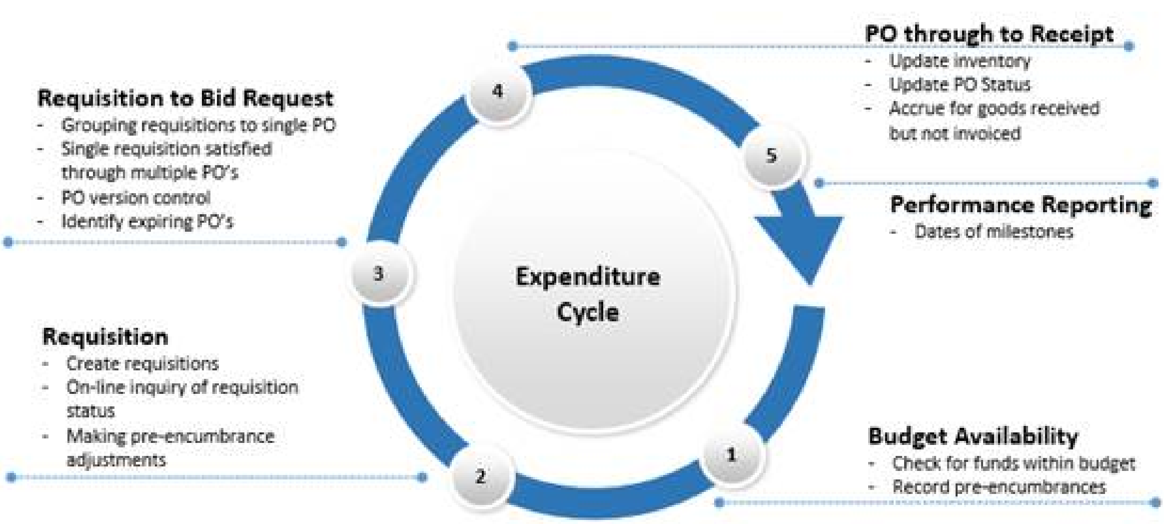
3.16 Procurement Module (I)

Proponents should provide an overview of the procurement module, providing an overview of how the module works, the workflow capabilities that exist within the module, how the module integrates with the GL and other FIS modules, the reporting functions that exist specific to the procurement, and a description of the configurability of the Procurement Master File.

Screenshots to illustrate the look and feel of the system should be provided, which will help BPI to understand the ease with which an authorized user can navigate within the procurement module to complete daily functions.

3.16.1 Workflow Capabilities within the Expenditure Cycle (I)

In addition to the overview of workflow automation, proponents are asked to specifically address how their products can automate the workflow or bring efficiencies to the tasks commonly associated with the Expenditure Cycle. With respect to the Expenditure Cycle proponents should include a list of purchase types to which the workflow automation capabilities apply (e.g., Inventory, Professional services, Blanket orders, etc.).



3.16.1.1 Budget Availability (I)

BPI would like to understand any possible workflow enhancements that the proposed FIS offers to the beginning stages of the expenditure cycle. For example, proponents are requested to address:

i. In the preparation of a requisition, will the FIS check the budget for availability of funds? If such controls exist, is it possible for an authorized user to override the control?

ii. Will the system allow budget control to be applied to a “rolled-up” budget or is it restricted to the specific budget categories? Is there flexibility in the way that the budget check is applied (e.g., current period, year to date, annual, etc.)?

iii. If required, will pre-encumbrances be recorded?

iv. Explain how the system provides the ability to minimize data entry requirements for routine purchases?

v. Through the purchasing process, can a user attach electronic files (PDF, Word, Excel, etc.) to purchasing documents?

3.16.1.2 Requisitions (I)

BPI would like to understand if the proposed FIS includes any workflow automation, or opportunities to streamline the processes associated with the creation of a requisition. For example, proponents should address:

i. The system’s ability to either centralize and/or distribute on-line entry and update of requisitions, purchase orders, and quotes/bids

ii. The system’s ability to provide on-line access to current and historical data for requisitions, purchase orders, quotes, bids, and proposals

iii. The system’s ability to provide a document copy capability (i.e., where data from existing documents can be copied into a new document and revised as needed). For example, can information from an existing requisition be copied to a new requisition? For what other forms is this process available?

iv. Provide the capability to revise print layouts of standard system forms (requisition, purchase order, Invitations to Bid, Requests for Quotes, and Requests for Proposals) generated.

v. Does the system recognize if multiple requisitions are requested by separate requestors for common vendors, to possibly result in a single PO being issued?

3.16.1.3 Bid Requests (I)

BPI would like to understand if the proposed FIS creates opportunities to streamline the business process required to move from the requisition to possible bid requests. Proponents should describe:

i. The system’s ability to provide on-line access to current and historical data for requisitions, purchase orders, quotes, bids, and proposals.

ii. The system’s capabilities to minimize data entry requirements for routine purchases, provide a document copy capability, where data from existing documents can be copied into a new document and revised as needed prior to final approval.

iii. Capabilities within the system to revise print layouts of standard system forms (requisition, purchase order, Invitations to Bid, Requests for Quotes, and Requests for Proposals) generated, including branding, and/or the terms and conditions that apply to different legal entities within the BEC group.

iv. The system’s ability to allow a user to attach electronic files (PDF, Word, Excel, etc.) to purchasing documents.

3.16.1.4 Purchase Orders (I)

BPI would like to understand if the proposed FIS creates opportunities to enhance the processes associated with managing a Purchase Order through to the receipt of goods. Proponents should describe:

i. The process within the proposed solution by which the user will manage encumbrance amounts for purchase orders.

ii. The process within the proposed solution by which the user will manage encumbrance adjustments (increase/decrease) for purchase order changes.

iii. The process within the proposed solution by which the user will manage clearing encumbrances for cancelled purchase orders.

iv. The proposed solution’s ability to provide at least five levels of automated approval and electronic routing on purchase orders, with an override capability for certain users.

v. How the proposed solution will manage encumbrance liquidations and expenditure amounts for vouchers.

vi. The proposed solution’s ability for PO roll over to release encumbrance and re-encumber using chart fields specified for each budget period.

vii. The proposed solution’s ability to roll outstanding encumbrances from one budget period accounting date to another budget period and accounting date.

3.16.1.5 Performance Reporting (I)

BPI would like to understand if the proposed FIS creates opportunities to enhance the processes associated with the final stages of the expenditure cycle.

i. Proponents should describe how the proposed solution can provide workflow enhancements which can impact performance reporting, for example:

   a. Budget to actual reports

   b. Summary of milestone dates in the expenditure process by department

   c. Summary of milestone dates in the expenditure process by vendor

3.17 Inventory Module (I)

Proponents should provide an overview of the Inventory module, providing an overview of how the module works, the workflow capabilities that exist within the module, how the module integrates with the GL and other FIS modules, and the reporting functions that exist specific to the Inventory module.

Screenshots to illustrate the look and feel of the system should be provided, which will help BPI to understand the ease with which an authorized user can navigate within the Inventory module to complete daily functions.

3.17.1 Physical Inventory (I)

BPI's existing process manages physical inventory outside of the core FIS. With the move to a new FIS BPI will look to streamline some of their existing inventory management processes. Proponents should provide information demonstrating how the proposed solution can improve upon the existing inventory management processes by specifically addressing:

i. Will the system provide any possible workflow automation opportunities by allowing bar code scanning to streamline the physical inventory process and data entry into the system?

ii. Will the system—in an automated way—identify and report differences between fixed asset recording and physical counts of fixed assets? For items that are physically in inventory, will the system differentiate between assets that are being accounted for through the Fixed Asset module differently than assets that have been assigned for capital projects and/or assets that are inventory not yet assigned to projects (i.e. true spares)?

iii. Will the system report differences in physical counts based on dollar amount differences, unit amount differences, percentages based on dollars and provide audit trails of any/all adjustments?

iv. Will the system produce count sheets on a scheduled basis to allow certain departments to perform counts of user-specified asset types? Do you have the ability to have the system randomly select count sheets (e.g., the full count may not be performed except once per year, but each inventory item may be counted more than once per year)?

v. Will the system allow for multiple inventory classes and locations (e.g., different physical locations, different companies, trucks, etc.)? With respect to the nomenclature within the FIS (i.e., asset ID assigned by the system), is the FIS flexible in how the inventory is tracked within and across the different entities of the BEC group?

vi. Will the system allow "on-line" entry of counts for specified asset types for certain department? Does the proposed solution allow for authorized users to remotely (external to the LAN where the solution is provisioned) access the system and perform specific data entry functions, or access reports? If so what is the preferred method of connectivity, i.e. VPN, SSL, or RDP?

3.17.2 Inventory Tracking (I)

Certain significant assets (e.g., transformers and/or meters) are tracked in the GIS and CIS systems to provide for full system view of the connectivity model. These assets are typically purchased into inventory, issued to the system, and can be removed from the field for future use or be scrapped. BPI intends to use the FIS to track the specific item to inventory, fixed assets or expense as dictated by the transaction, including calculating depreciation and disposal gain or loss at the specific item level.

Proponents should describe how the inventory system of the proposed solution will allow the tracking of inventory quantities, reorder points, etc. by stock description while allowing for the tracking of a specific item's serial or unit numbers within that stock item.

3.18 Fixed Assets (I)

Proponents should provide an overview of the Fixed Assets module, providing an overview of how the module works, the workflow capabilities that exist within the module, how the module integrates with the GL and other FIS modules, the reporting functions that exist specific to the Fixed Assets module, and a description of the configurability of the Master File.

Screenshots to illustrate the look and feel of the system should be provided, which will help BPI to understand the ease with which an authorized user can navigate within the Fixed Assets module to complete daily functions.

BPI currently uses information from within multiple systems to track Fixed Assets, and perform the IFRS tracking of assets for reporting, and Capital Planning, according to the requirements for componentization of assets placed on Ontario utilities by the OEB. BPI would like to understand if the proposed FIS will present opportunities to enhance the existing business process. In addition to their general overview, proponents should address such specifics as:

i. Will the system allow electronic documents (e.g., photos, embedded plans, etc.) to be attached to an asset record?

ii. Will the system support integration to the Intergraph G-Tech Geospatial Information System (GIS)?

iii. Will the system maintain individual asset cost for base asset as well as total asset cost after improvements?

iv. Will the system maintain information about the condition of an asset?

v. Will the system allow assets to be designated as non-depreciable? Can asset disposal restrictions be established in the system?

vi. Will the system support user-defined asset categorization to align with the OEB approved componentization levels?

vii. What features exist to record and track costs related to self-constructed assets and direct purchase of tangible assets?

3.18.1 OEB Requirements for Cost of Service Rate Application (I)

BPI will be undertaking their next Cost of Service application in 2016 and are required by the OEB to follow the reporting requirements as outlined in Chapter 5 of the Consolidated Distribution System Plan. Proponents should explain how the proposed solution can assist BPI in fulfilling these reporting requirements and more generally how the product will improve the existing business processes for recording information and reporting on capital projects and the maintenance of Fixed Assets.

In addition to this overview, Proponents are asked to address:

1. Will the system group similar costs and report on these costs? For example,
    - Labour
    - Fleet
    - Material
    - Can subsets of costs be grouped on and reported on?

3.18.2 Asset Depreciation (I)

With regards to the depreciation of assets, proponents should explain how the proposed system handles the business processes associated with this important function in the utility environment, where some assets are tracked individually, while others are treated as pooled assets. Proponents should address the following questions:

i. Does the proposed solution provide electronic notification to appropriate users when asset's useful life threshold is nearing end of useful life?

ii. Does the proposed solution provide depreciation schedules on fixed assets?

iii. Does the proposed solution automatically calculate depreciation in accordance with the depreciation method and convention designated for an asset?

iv. Does the proposed solution maintain multiple asset basis values for each asset if desired, utilizing industry-standard depreciation methods?

v. Does the proposed solution automatically charge depreciation to multiple chart of accounts for split ownership assets?

vi. Does the proposed solution allow user-defined time periods for recording depreciation (posting)?

vii. Does the proposed solution support use of multiple depreciation methods:

   a. Straight line

   b. Weighted average for tracked pools

   c. User-defined

viii. Does the proposed solution support simulating depreciation calculations of an asset or a group of assets without posting the result?

ix. Does the proposed solution prevent depreciating an asset's value below zero or below a user-specified value?

x. Does the proposed solution automatically recalculate depreciation expenses when asset useful life, value basis, salvage value, or defined depreciation method change? **Note: Recalculation should be only on the remaining value of the asset (NBV). What has been posted in the past should not change.**

xi. Does the proposed solution calculate depreciation for construction in progress at project close?

xii. Will the proposed solution be capable of replicating the asset lifecycle model that is currently used in the Asset Management system (UEM)? Proponents should describe the flexibility and configurability of the FIS with regards to Asset Management.

xiii. Will the proposed solution provide the ability to have secondary depreciation groupings and rates to allow the same asset to calculate regular depreciation and Capital Cost Allowance for tax purposes?

3.19 Job Costing (I)

Proponents should provide an overview of the Job Costing module, providing an overview of how the module works, the workflow capabilities that exist within the module, how the module integrates with the GL and other FIS modules, the reporting functions that exist specific to Job Costing, and a description of the configurability of the Master File.

Screenshots to illustrate the look and feel of the system should be provided, which will help BPI to understand the ease with which an authorized user can navigate within the module to complete daily functions.

Currently BPI uses an external system, and processes, outside of the FIS to determine and prioritize projects. In addition to their general overview, proponents should specifically address:

i. Does the system identify and record all capital costs associated with the construction or purchase of an asset?

ii. Does the system provide any workflow automation to determine any assets to be capitalized or any change in the asset?

iii. Will the system produce notification of project status based on user-defined criteria? When projects are delayed, or accelerated, does the system allow a user to track the reasons associated with such changes? Can a user add free form text for future reporting requirements on capital projects?

iv. Will the system recognize fixed/capital assets when they are in service, regardless of whether the project has been completed?

v. Can the system integrate with purchasing and project accounting systems to capture costs for construction assets?

vi. Proponents should demonstrate experience integrating to external Asset Management tools. List the products that the proposed solution has been integrated with, for the purpose of managing Capital Projects. What was the integration methodology used to link the systems (i.e. web services, file based, etc.)?

vii. Through the job costing process, with the proposed solution produce a Bill of Materials?

3.19.1 Work Order Management (I)

As shown in Section 3.2.1, BPI currently creates work orders in Daffron, but reports on work orders using JDE, and performs job costing externally to the Daffron and JDE systems. BPI requires a comprehensive understanding of how work orders are managed by the proposed solution. In addition to an overview of work order management within the FIS solution, proponents should specifically address:

i. Will the proposed solution track Life to Date (LTD) for capital projects via the work order? If BPI is managing a project that crosses fiscal year ends or if one were to last beyond a full calendar year, will the work order's track current month, current year and life to date?

ii. How and when a work order for a self-constructed asset is reflected in the general ledger and the fixed asset module?

iii. What differences exist between a work order for capital work on a self-constructed asset vs. capital work on a tangible asset vs. a refillable work order vs. standing (or recurring) OM&A work order?

iv. Certain work orders for a particular project may contain asset elements that require separate accounting (e.g., a work order is created for a new connection, where the new connection includes a new meter and new transformer). While the different elements will need to map to the applicable balance sheet accounts, BPI expects that the work order will capture the complete costs for the project. Proponents should describe how the proposed solution allows the capture of total costs including offsetting revenues or capital contributions and still maps correctly to the applicable GL accounts.

v. When a work order is complete, how does the change in status impact the final accounting for the work order? Will the system close the project or will manual attention be required?

vi. What job costing mapping and grouping capabilities exist to allow maximum analytics?

3.19.2 Engineering Standards

Currently, BPI manages and maintains its own utility engineering standards outside of the core FIS. Integration has been created between disparate systems so that the FIS can be used to create a Bill of Materials based upon a design. BPI is interested in understanding the efficiencies that are introduced into this process by having work orders, inventory, and the job costing all handled within the same solution.

The following sections will address how the proposed solution can be used to manage BPI's Engineering Standards, or how the proposed solution will be used to enhance the existing processes.

3.19.2.1 Managing the Existing Standards (I)

Currently BPI manages their Engineering Standards in a Microsoft Excel workbook, with integration to the FIS so that FIS can be used to create a Bill of Materials based upon a design. Proponents should explain whether the proposed solution can be used to manage BPI's existing standards, and what the proposed Business Process would be to handle the Engineering Standards. In their response, proponents should be sure to address:

i. Proponents should explain whether their system provides an integrated solution which can produce a Bill of Materials based on the design and the current inventory within the FIS (and whether additional integration costs are required to create a streamlined process).

ii. Will the proposed solution create a Bill of Materials for a standard design or inventory lists based upon ESA 22/04 equipment approval sheets?

iii. Will the proposed system generate estimates for a Bill of Materials based on standard designs?

iv. Does the proposed system allow the material listed in the Bill of Material to be committed from inventory to a work order or job?

v. Does the inventory module produce purchase order requests for any material that has now been committed based on the actual inventory, item reorder points and item maximum quantities?

3.19.2.1 Standardized Engineering Standards (I)

BPI is interested in learning how the proposed solution might enhance its existing process by acquiring their standards through an externally managed standards forum such as USF (Utilities Standards Forum), where a Material Database can be accessed, providing information about which (and how many) component parts form each standard. Proponents should provide any insight they may have regarding the business processes most commonly used with the proposed solution in the management of engineering standards, and how these processes can lead to a more streamlined process for Job Costing, Inventory management, etc.

3.20 Capital Projects (I)

For Capital Projects, BPI's existing process includes managing Job Costing, and Fixed Assets outside of the core FIS. With the procurement of a new FIS, BPI looks to optimize the accounting procedures for Capital Projects. Proponents should describe how the proposed system can help to streamline their existing process, with information provided to specifically address:

i. Will the solution provide the ability to define project phases with configurable processing rules for each phase?

ii. Will the solution provide the ability for electronic project approval through workflow automation or remote access into the system?

iii. Will the solution provide the ability to record project budgets against project phases?

iv. Will the solution ensure that work phases can be mapped to GL accounts?

v. As work progresses, if changes to work phases occur, will the system track the changes to approved budgets and maintain a history of budgets and cash flow?

vi. Will the solution provide budget forecasting and budget allocation in future years and provide "what-if" forecasting?

vii. Will the solution track funding sources across projects and carry forward balances from year to year?

viii. Will the solution allocate direct and indirect financing costs to projects?

ix. Will the solution transfer in-progress accounts to fixed assets at project close? Will the system prevent a user from inactivating a project that has not been closed?

3.20.1 Project Set-up (I)

As with all Local Distribution Companies in the province of Ontario, BPI must meet the requirements of the Ontario Energy Board. In recent years, the OEB has begun to require that utilities modify the business processes associated with Capital Projects; for example, utility assets are now componentized, and depreciated according to useful lives. LDCs are expected to provide increasingly detailed documentation of their Capital Projects, such as the prioritization of projects, the decision making process when project priorities are modified, etc. All of this information is captured in the utility's Cost of Service application; a process which BPI will undertake in 2016.

In order to better understand how the proposed solution can improve BPI's processes as they related to capital projects, and the set-up of projects within the FIS, Proponents are asked to address:

i. Does the proposed solution allow multiple year projects? Does the solution allow for parent/child relationships for projects and sub-projects?

ii. Does the system track funding sources? Can projects be established across multiple funds and departments?

iii. Is there workflow notification/approval for project setup?

iv. Does the proposed solution track start/end dates?

v. Does the system allow for the creation of a project budget for select projects? Can project budgets be established by fiscal year within a multi-year budget? Will the system control a budget at the project level or the sub-project level?

3.21 Implementation of the FIS (I)

The proponent will be asked to provide sample implementation plans that outline the key steps involved in integrating the FIS into BPI's production environment. When considering the proposed plans, proponents should consider that BPI would prefer to go live with the FIS, or certain modules of the FIS in early 2016. Recognizing that this may not be considered ideal proponents might consider providing their ideal plan based on their experience in other projects, as well as an accelerated plan which demonstrates how certain aspects of the ideal plan could be compressed to achieve the more aggressive goals of BPI. In the more aggressive plan, proponents should note the key points at which risk is introduced and how BPI can best avoid any commonly experienced pitfalls.

BPI would also like to understand the internal resource requirements that the implementation of the FIS will create for their organization. Many departments will be impacted by the installation of this application and proponents should indicate in their responses which resources will be key members of the entire implementation and when subject matter experts from various departments will be needed to participate in the implementation.

Key considerations such as holiday schedules, conflicting projects, and previously assigned duties need to be taken into consideration when planning the implementation. As such, the plan should accurately reflect the number of resources expected to participate on behalf of BPI during this engagement, as well as build in some contingency time to deal with any issues similar to the ones listed above.

3.21.1 Implementation Experience

In order to mitigate the risk associated with implementing significant change, such as that brought about through the purchase and deployment of a critical system, BPI requires that proponents are able to demonstrate success and stability through previous experience deploying the proposed solution.

In addition to describing experience with the Local Distribution Company (LDC) environment, proponents should include experience related to LDC affiliate companies. Of particular interest to BPI is the proponent's experience in the Ontario market.

3.21.2 Project Management (I)

Proponents should provide at least three (3) references where the proposed system was deployed:

i. On-time; state the actual business days required to deploy as a percentage of the required business days to deploy

ii. On-budget; provide the cost of the deployed project as a percentage of the proposed budget

Additionally, proponents should describe their approach to project management, how issues are tracked, how updates are provided, how escalation is managed, etc.

3.21.3 Data Conversion (I)

Proponents should describe their experience working with utilities that are moving from the Daffron and/or JDE financial systems. Additionally, proponents should describe their experience working with organizations that were not operating with a single source of financial data prior to the implementation of the proposed FIS.

As a result of the experiences listed, proponents should provide their proposed deployment plan illustrating the order in which BPI might convert data and begin using modules, and the anticipated schedule to fully deploy the proposed solution. This migration plan should include details around the integration to external systems, and the Best Practice approach to minimize the risk associated with impacting production systems and processes.

3.21.4 Business Process Documentation for the FIS (I)

BPI follows best practices with regards to Business Process documentation and would like to ensure that processes have been documented in advance of the new FIS moving to the Production environment.

To this end, BPI expects that the Proponent will provide Business Process documentation in advance of any training, and that the proponent will ensure that process documentation is updated with any specific decisions made with respect to the configuration of the FIS for deployment at BPI. Proponents should explain the intended process by which BPI will be provided with Business Process documentation and the process by which documents are updated through the conversion and deployment process as configurable settings in the FIS are discussed and established.

3.22 Training Requirements (I)

BPI requires that all staff involved in the deployment and operation of the FIS System be trained. If BPI determines that there are specific training and testing gaps, the proponent will be required to complete the required additional training before the FIS software is moved to the Production environment.

BPI expects that at minimum documentation for the training should include:

- System overview description
- System flow charts
- File descriptions and record layouts
- Description of program function and logic
- Back-up and recovery procedures
- Operating procedures,
- Screen layouts
- Data entry procedure
- Report descriptions
- Descriptions of all user options and operations
- Descriptions of all error messages

Proponents should provide their training plan, and any material that demonstrates the comprehensive nature of the training.

3.23 Quality Assurance and Change Management

3.23.1 Quality Assurance (I)

BPI expects that quality assurance plans should identify documents, standards, and practices governing the product development and identify measures and procedures for problem reporting and corrective action. The proponent is asked to provide details (workflow or description of how QA is handled) on the company's quality assurance plan or process for the FIS product including details on the proponent responds to:

- Service/support related problems
- Software quality problems

3.23.2 Change Management (I)

BPI follows best practices with regards to change management for its systems. For example, BPI will:

- Ensure that all changes represent an acceptable balance of risk, disruption to users and resource effectiveness.
- Ensure that all changes are processed and communicated in a timely and efficient manner.
- Ensure that the changes are processed in a manner that minimizes the impact of change related problems.

Proponents are asked to provide the anticipated or recommended change management process as it relates to the FIS, specifically addressing:

- Change management controls
- Anticipated frequency of releases and the suggested manner in which this schedule can be managed by the utility
- An appropriate level of testing for upgrades and version releases
- Process by which release notes are provided to customers and reviewed for impact
- Proper approvals
- Timely notification to users
- Adequate training for BPI staff
- Back out procedures
- An integrated schedule with other changes
- Lessons learned processes or documentation to be used the next time change is implemented
- Identify security measures if changed
- Release notes (include samples, and description of the process to release them to customers and review them with customers)
- Test scripts (include samples and description of how they are created in conjunction with their customers in preparation for software upgrades or version releases)

3.23.3 Resource Requirements (to facilitate change management) (I)

As indicated in Section 3.1, BPI currently subscribes to IT services through the existing SLA with the COB. To provide BPI with some context for their analysis of the hosted model, proponents are asked to describe the expected level of resources that would be required for ongoing change management of the proposed FIS solution, and how this might compare to the licensed (i.e., owned and on-premise) ownership model.

3.24 Ongoing Support Requirements (I)

It is anticipated that support will follow a tiered structure whereby the utility will describe a support item complete with priority (i.e., High, Med, and Low). The proponent should describe its support structure and the guaranteed time to respond to and resolve issues within different levels of priority.

Additionally, the proponent should provide a description of its intended support system for the FIS, including the following:

- Location(s) of support personnel
- Hours of support
- Organizational structure of support team(s)
- Support escalation process
- Support tools used (phone line only, ticket access, SO ticket access view, etc.)

3.24.1 Resource Requirements (to facilitate support) (I)

As indicated in Section 3.1 BPI currently subscribes to IT services through the existing SLA with the COB. To provide BPI with some context for their analysis of hosted and licensed models, proponents are asked to describe the expected level of resources that would be required in the licensed (on premise) model for ongoing operation and maintenance of the proposed FIS solution.

3.24.2 System Configurability (I)

With regards to the configurability of the system setup, proponents should describe the differences, if any, in how BPI will be able to setup the proposed solution. For example:

i. In a hosted environment is there reduced flexibility in the setup of the Chart of Accounts, as compared to the process by which BPI would perform the same functions in an owned and on-premise solution?

ii. In a hosted environment, when the OEB or some other regulatory body mandates changes to (for example) reporting requirements that impact the manner in which the FIS is configured, what is the process for BPI to implement the required changes? How does this compare with the owned and on-premise solution?

iii. Should BPI, or one of its affiliates, decide to modify the system configuration post go-live, what is the process to work with the hosting supplier to accommodate the desired changes? How does this compare with the owned and on-premise solution?

BID NOTICE

PROVISION OF FINANCIAL INFORMATION SYSTEM FOR BRANTFORD POWER INC.

RFP 15-17

CLOSING DATE: Thursday, May 14, 2015 3:00:59 PM

Project Description

This Request for Proposals (the "RFP") is an invitation by Brantford Power Incorporated ("BPI") to prospective proponents to submit proposals for the provision of Financial Information System for BPI**,** as further described in the RFP Particulars (Appendix D) (the "Deliverables").

BPI's preference is for a hosted FIS solution. The data centre must reside in Canada. Data cannot cross the Canadian border for any reason.

BPI considers the following list of items as required to successfully satisfy the intent of this RFP:

- Project management, system design, commissioning, and training;
- Creation and implementation of all required interfaces including technical expertise required to establish communications between the FIS and BPI's back office systems;
- System security (i.e., detailed security parameters to protect all information collected and stored);
- Service levels and value added services;
- Applicable costs, pricing and rates;
- Conversion assistance to convert from the existing FIS solution(s) to the new FIS;
- Detailed reporting functionality;
- Business Intelligence; and
- Ongoing technical support and updates.

This RFP bid solicitation is being issued by the City of Brantford on behalf of Brantford Power Inc. All issues related to this RFP pre-award shall be dealt with by the City, on behalf of Brantford Power Inc. The agreement shall be between Brantford Power Inc. and the selected proponent.

This RFP is only available electronically.

The cost for the Request for Proposals document is $43.05 (including HST), payable in cash, debit, Visa or Mastercard, or cheque made payable to the Corporation of the City of Brantford. This fee is non-refundable.

Proponents are to send their requests, along with their method of payment and complete contact information (including name of company, contact name, address, phone, fax and email address) to: purchasing@brantford.ca Visa or Mastercard information can be provided by phone at 519.759.4150 x4278.

Contact: Eva Cislo, Buyer

PLEASE REFER TO THE ASSOCIATED DOCUMENT(S) FOR FURTHER DETAILS.

Appendix C - Pricing Form (Schedule of Prices)

ADDITIONAL UNIT PRICES FOR EXTRA WORK

No payment will be made to the contractor unless the extra work is ordered by Brantford Power Incorporated.

Additional Resources	Hourly Rate
Solutions Architect	$ -
Principal Consultant	$ -
Program Manager	$ -
Application Consultant	$ -
Principal Software Engineer	$ -
Principal Data Analyst	$ -
Senior Software Engineer	$ -
Systems Engineer	$ -
Software Engineer	$ -

Additional Incidental Costs	Price
Travel Time and Mileage Costs (per diem)	$ -
System Training (per diem)	

Overview:

Instructions

Appendix C - Pricing Form (Schedule of Prices)

Within this workbook multiple tabs are included so that proponents can include detailed price information allowing BPI to perform an "apples-to-apples" comparison. Tabs are provided for each of the required environments, and also in the event that proponents would like to provide alternate pricing for an On-Premise solution. The tabs include sections for the FIS solution and its component modules in the event that the pricing

BPI has provided indication of the number of users of each module in the event that the proponents licensing is "seat-based". Separate sections within the tabs are provided for Third Party License costs as well as Integration Fees, and Training costs.

And finally, there is a tab provided for proponents to complete that shows rates for Additional Resources, should they be required.

proposal, the proponent is required to enter the base system price and price per module into Section 1, the cost of the 3rd party licenses into Section 2 for each of the modules that form the proposed system, the anticipated integration costs to make each module fully functional into Section 3 and the anticipated Training fees into Section 4. If the proponents proposed cost is not modular in nature, it is acceptable to enter the "All In" cost into the "Base FIS System Price" for each of these sections.

Section 5 requests "Pricing Confidence"; this is an indication of the confidence in the proposed cost. For example, a 90% confidence indicates that during contract negotiation when additional information is exchanged between the proponent and BPI, the Proponent expects their proposed cost will change by 10% or less. BPI's strong preference is that the proposed cost is provided with 100% certainty which would indicate a firm price. Proponents which provide a Pricing Confidence of less than 100% will be required (if invited to a demonstration) to explain what is preventing them from providing a cost with 100% certainty, with the intent that BPI provide explanation where a lack of clarity exists so that the proponent can increase their confidence in the bid price to

Section 6 on the "Hosted" tabs allows Proponents to insert a cost that would allow BPI to move from a Hosted model to an On-Premise solution.

Brantford Powe			
(1) Pricing: Hosted Model	Customer Base (electric meters)	Number of Users	Price Per Meter Per Month
Base FIS System Price	40,000	0	$ -
3.3 Hardware Specifications	40,000	0	$ -
3.5 Modules	40,000	0	$ -
3.6 Data Management	40,000	0	$ -
3.7 Security	40,000	0	$ -
3.8 Reporting	40,000	0	$ -
3.9 Business Intelligence	40,000	0	$ -
3.10 Workflow Automation	40,000	0	$ -
3.11 General Ledger	40,000	30	$ -
3.12 Accounts Payable	40,000	15	$ -
3.13 Accounts Receivable	40,000	15	$ -
3.14 Cash Management	40,000	20	$ -
3.16 Procurement	40,000	15	$ -
3.17 Inventory	40,000	20	$ -
3.18 Fixed Assets	40,000	15	$ -
3.19 Job Costing	40,000		$ -
3.20 Capital Projects	40,000	20	$ -
Provisional Pricing			
3.15 HR and Payroll	40,000	65	$ -
Totals - Hosted Model			$0.00

(2) Third Party License Requirements	Third Party Licenses Required	Price
Base FIS System Price		$ -
3.3 Hardware Specifications		$ -
3.5 Modules		$ -
3.6 Data Management		$ -
3.7 Security		$ -
3.8 Reporting		$ -
3.9 Business Intelligence		$ -
3.10 Workflow Automation		$ -
3.11 General Ledger		$ -
3.12 Accounts Payable		$ -
3.13 Accounts Receivable		$ -
3.14 Cash Management		$ -
3.16 Procurement		$ -
3.17 Inventory		$ -
3.18 Fixed Assets		$ -
3.19 Job Costing		$ -
3.20 Capital Projects		$ -
Provisional Pricing		
3.15 HR and Payroll		$ -
Totals - Third Party License Requirements		**$ -**

(3) Integration Fees	Total Hours	Hourly Rate	Total Imple /Integrati
Base FIS System Price	0	$ -	$
3.4 Integration of the FIS	0	$ -	$
3.4.1 Integration with the GIS	0	$ -	$
3.4.2 Integration with the CIS	0	$ -	$
3.4.3 Integration Methodology	0	$ -	$
3.4.4 Integration to other downstream systems	0	$ -	$
Integration to Workforce Management	0	$ -	$
Integration to Banking systems	0	$ -	$
Integration to Payroll data entry system	0	$ -	$
Integration to Inventory bar coding system	0	$ -	$
Enter additional integration item and cost	0	$ -	$
Enter additional integration item and cost	0	$ -	$
Enter additional integration item and cost	0	$ -	$
3.3 Hardware Specifications	0	$ -	$
3.5 Modules	0	$ -	$
3.6 Data Management	0	$ -	$
3.7 Security	0	$ -	$
3.8 Reporting	0	$ -	$
3.9 Business Intelligence	0	$ -	$
3.10 Workflow Automation	0	$ -	$
3.11 General Ledger	0	$ -	$
3.12 Accounts Payable	0	$ -	$
3.13 Accounts Receivable	0	$ -	$
3.14 Cash Management	0	$ -	$
3.16 Procurement	0	$ -	$
3.17 Inventory	0	$ -	$
3.18 Fixed Assets	0	$ -	$
3.19 Job Costing	0	$ -	$
3.20 Capital Projects	0	$ -	$
Provisional Pricing			
3.15 HR and Payroll	0	$ -	
Totals - Integration Fees			**$0.**

(4) Training Fees	Year 1 Total Hours	Year 1 Hourly Rate	Total Year 1 T
Base FIS System Price	$ -	$ -	$
3.22 Training Requirements	$ -	$ -	$
3.23 Quality Assurance and Change Management	$ -	$ -	$
3.24 Ongoing Support Requirements	$ -	$ -	$
3.2.4 Customer Information System	$ -	$ -	$
3.2.5 Outage Management System	$ -	$ -	$
3.2.6 Work Force Management	$ -	$ -	$
3.2.7 Geographic Information System	$ -	$ -	$
3.2.8 3rd Party Interfaces	$ -	$ -	$
3.3 Hardware Specifications	$ -	$ -	$
3.5 Modules	$ -	$ -	$
3.6 Data Management	$ -	$ -	$
3.7 Security	$ -	$ -	$
3.8 Reporting	$ -	$ -	$
3.9 Business Intelligence	$ -	$ -	$
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3.18 Fixed Assets	$ -	$ -	$
3.19 Job Costing	$ -	$ -	$
3.20 Capital Projects	$ -	$ -	$
Provisional Pricing			
3.15 HR and Payroll			
Totals - Training Fees			**$**

(5) Pricing Confidence		
Level of Confidence in Pricing Submitted	0.00%	
required to submit a level of confidence with the pricing they have provided (i.e. + / - 10%) or a statement of the pricing as a range. Include any key assumptions that have been made in developing the estimate and identify and factors that would cause the estimate to be altered.		

(6) Cost to Migrate from Hosted to License	**Price**	
License Fees	$ -	
Integration Fees	$ -	
Other	$ -	

Total Costs: Hosted Production FIS
$0.00
Total Costs = 10 years of Hosted fees, 10 years license fees, 1 year training, and all integration cost

r: Financial Information System (FIS) Hosted Model Pricing for Production System

Total Year 1 Hosting Costs	Total Year 2 Hosting Costs	Total Year 3 Hosting Costs	Total Year 4 Hosting Costs	Total Year 5 Hosting Costs	Total Year 6 Hosting Costs	Total Year 7 Hosting Costs
$ -	$ -	$ -	$ -	$ -	$ -	$ -
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Total License Price	Year 1 Maintenance Price	Year 2 Maintenance Price	Year 3 Maintenance Price	Year 4 Maintenance Price	Year 5 Maintenance Price	Year 6 Maintenance Price
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raining Costs	On Going Total Hours	On Going Hourly Rate	Total On Going Training Costs
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Bidder Pricing Confidence Notes

Bidder Migration Notes

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Total Year 8 Hosting Costs	Total Year 9 Hosting Costs	Total Year 10 Hosting Costs	10 Year Total Hosting Costs
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Brantford P

(1) Pricing: Hosted Model	Customer Base (electric meters)	Number of Users	Price Per Meter Per Month
Base FIS System Price	40,000	0	$ -
3.3 Hardware Specifications	40,000	0	$ -
3.5 Modules	40,000	0	$ -
3.6 Data Management	40,000	0	$ -
3.7 Security	40,000	0	$ -
3.8 Reporting	40,000	0	$ -
3.9 Business Intelligence	40,000	0	$ -
3.10 Workflow Automation	40,000	0	$ -
3.11 General Ledger	40,000	30	$ -
3.12 Accounts Payable	40,000	15	$ -
3.13 Accounts Receivable	40,000	15	$ -
3.14 Cash Management	40,000	20	$ -
3.16 Procurement	40,000	15	$ -
3.17 Inventory	40,000	20	$ -
3.18 Fixed Assets	40,000	15	$ -
3.19 Job Costing	40,000		$ -
3.20 Capital Projects	40,000	20	$ -
Provisional Pricing			
3.15 HR and Payroll	40,000	65	$ -
Totals - Hosted Model			$0.00

(2) Third Party License Requirements	Third Party Licenses Required	Price
Base FIS System Price		$ -
3.3 Hardware Specifications		$ -
3.5 Modules		$ -
3.6 Data Management		$ -
3.7 Security		$ -
3.8 Reporting		$ -
3.9 Business Intelligence		$ -
3.10 Workflow Automation		$ -
3.11 General Ledger		$ -
3.12 Accounts Payable		$ -
3.13 Accounts Receivable		$ -
3.14 Cash Management		$ -
3.16 Procurement		$ -
3.17 Inventory		$ -
3.18 Fixed Assets		$ -
3.19 Job Costing		$ -
3.20 Capital Projects		$ -
Provisional Pricing		
3.15 HR and Payroll		$ -
Totals - Third Party License Requirements		**$ -**

(3) Integration Fees	Total Hours	Hourly Rate	Total Imple /Integrati
Base FIS System Price	0	$ -	$
3.4 Integration of the FIS	0	$ -	$
3.4.1 Integration with the GIS	0	$ -	$
3.4.2 Integration with the CIS	0	$ -	$
3.4.3 Integration Methodology	0	$ -	$
3.4.4 Integration to other downstream systems	0	$ -	$
Integration to Workforce Management	0	$ -	$
Integration to Banking systems	0	$ -	$
Integration to Payroll data entry system	0	$ -	$
Integration to Inventory bar coding system	0	$ -	$
Enter additional integration item and cost	0	$ -	$
Enter additional integration item and cost	0	$ -	$
Enter additional integration item and cost	0	$ -	$
3.3 Hardware Specifications	0	$ -	$
3.5 Modules	0	$ -	$
3.6 Data Management	0	$ -	$
3.7 Security	0	$ -	$
3.8 Reporting	0	$ -	$
3.9 Business Intelligence	0	$ -	$
3.10 Workflow Automation	0	$ -	$
3.11 General Ledger	0	$ -	$
3.12 Accounts Payable	0	$ -	$
3.13 Accounts Receivable	0	$ -	$
3.14 Cash Management	0	$ -	$
3.16 Procurement	0	$ -	$
3.17 Inventory	0	$ -	$
3.18 Fixed Assets	0	$ -	$
3.19 Job Costing	0	$ -	$
3.20 Capital Projects	0	$ -	$
Provisional Pricing			
3.15 HR and Payroll	0	$ -	
Totals - Integration Fees			**$0.**

(4) Training Fees	Year 1 Total Hours	Year 1 Hourly Rate	Total Year 1 T
Base FIS System Price	$ -	$ -	$
3.22 Training Requirements	$ -	$ -	$
3.23 Quality Assurance and Change Management	$ -	$ -	$
3.24 Ongoing Support Requirements	$ -	$ -	$
3.2.4 Customer Information System	$ -	$ -	$
3.2.5 Outage Management System	$ -	$ -	$
3.2.6 Work Force Management	$ -	$ -	$
3.2.7 Geographic Information System	$ -	$ -	$
3.2.8 3rd Party Interfaces	$ -	$ -	$
3.3 Hardware Specifications	$ -	$ -	$
3.5 Modules	$ -	$ -	$
3.6 Data Management	$ -	$ -	$
3.7 Security	$ -	$ -	$
3.8 Reporting	$ -	$ -	$
3.9 Business Intelligence	$ -	$ -	$
3.10 Workflow Automation	$ -	$ -	$
3.11 General Ledger	$ -	$ -	$

3.12 Accounts Payable	$ -	$ -	$
3.13 Accounts Receivable	$ -	$ -	$
3.14 Cash Management	$ -	$ -	$
3.16 Procurement	$ -	$ -	$
3.17 Inventory	$ -	$ -	$
3.18 Fixed Assets	$ -	$ -	$
3.19 Job Costing	$ -	$ -	$
3.20 Capital Projects	$ -	$ -	$
Provisional Pricing			
3.15 HR and Payroll			
Totals - Training Fees			**$**

(5) Pricing Confidence		
Level of Confidence in Pricing Submitted	0.00%	
submit a level of confidence with the pricing they have provided (i.e. + / - 10%) or a statement of the pricing as a range. Include any key assumptions that have been made in developing the estimate and identify and factors that would cause the estimate to be altered.		

(6) Cost to Migrate from Hosted to License Model	**Price**	
License Fees	$ -	
Integration Fees	$ -	
Other	$ -	

Total Costs: Hosted Test FIS
$0.00
Total Costs = 10 years of Hosted fees, 10 years license fees, 1 year training, and all integration cost

Appendix C - Pricing Form (Schedule of Prices)

ower: Financial Information System (FIS) Hosted Model Pricing for Test System

Total Year 1 Hosting Costs	Total Year 2 Hosting Costs	Total Year 3 Hosting Costs	Total Year 4 Hosting Costs	Total Year 5 Hosting Costs	Total Year 6 Hosting Costs	Total Year 7 Hosting Costs
$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -
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$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Total License Price	Year 1 Maintenance Price	Year 2 Maintenance Price	Year 3 Maintenance Price	Year 4 Maintenance Price	Year 5 Maintenance Price	Year 6 Maintenance Price
$ -	$ -	$ -	$ -	$ -	$ -	$ -
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raining Costs	On Going Total Hours	On Going Hourly Rate	Total On Going Training Costs
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Bidder Pricing Confidence Notes

Bidder Migration Notes

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Total Year 8 Hosting Costs	Total Year 9 Hosting Costs	Total Year 10 Hosting Costs	10 Year Total Hosting Costs
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Year 7 Maintenance Price	Year 8 Maintenance Price	Year 9 Maintenance Price	Year 10 Maintenance Price	Total Maintenance Costs
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Brantford Power: Fina

(1) Pricing: Hosted Model	Customer Base (electric meters)	Number of Users	Price Per Meter Per Month
Base FIS System Price	40,000	0	$ -
3.3 Hardware Specifications	40,000	0	$ -
3.5 Modules	40,000	0	$ -
3.6 Data Management	40,000	0	$ -
3.7 Security	40,000	0	$ -
3.8 Reporting	40,000	0	$ -
3.9 Business Intelligence	40,000	0	$ -
3.10 Workflow Automation	40,000	0	$ -
3.11 General Ledger	40,000	30	$ -
3.12 Accounts Payable	40,000	15	$ -
3.13 Accounts Receivable	40,000	15	$ -
3.14 Cash Management	40,000	20	$ -
3.16 Procurement	40,000	15	$ -
3.17 Inventory	40,000	20	$ -
3.18 Fixed Assets	40,000	15	$ -
3.19 Job Costing	40,000		$ -
3.20 Capital Projects	40,000	20	$ -
Provisional Pricing			
3.15 HR and Payroll	40,000	65	$ -
Totals - Hosted Model			$0.00

(2) Third Party License Requirements	Third Party Licenses Required	Price
Base FIS System Price		$ -
3.3 Hardware Specifications		$ -
3.5 Modules		$ -
3.6 Data Management		$ -
3.7 Security		$ -
3.8 Reporting		$ -
3.9 Business Intelligence		$ -
3.10 Workflow Automation		$ -
3.11 General Ledger		$ -
3.12 Accounts Payable		$ -
3.13 Accounts Receivable		$ -
3.14 Cash Management		$ -
3.16 Procurement		$ -
3.17 Inventory		$ -
3.18 Fixed Assets		$ -
3.19 Job Costing		$ -
3.20 Capital Projects		$ -
Provisional Pricing		
3.15 HR and Payroll		$ -
Totals - Third Party License Requirements		**$ -**

(3) Integration Fees	Total Hours	Hourly Rate	Total Imple /Integrati
Base FIS System Price	0	$ -	$
3.4 Integration of the FIS	0	$ -	$
3.4.1 Integration with the GIS	0	$ -	$
3.4.2 Integration with the CIS	0	$ -	$
3.4.3 Integration Methodology	0	$ -	$
3.4.4 Integration to other downstream systems	0	$ -	$
Integration to Workforce Management	0	$ -	$
Integration to Banking systems	0	$ -	$
Integration to Payroll data entry system	0	$ -	$
Integration to Inventory bar coding system	0	$ -	$
Enter additional integration item and cost	0	$ -	$
Enter additional integration item and cost	0	$ -	$
Enter additional integration item and cost	0	$ -	$
3.3 Hardware Specifications	0	$ -	$
3.5 Modules	0	$ -	$
3.6 Data Management	0	$ -	$
3.7 Security	0	$ -	$
3.8 Reporting	0	$ -	$
3.9 Business Intelligence	0	$ -	$
3.10 Workflow Automation	0	$ -	$
3.11 General Ledger	0	$ -	$
3.12 Accounts Payable	0	$ -	$
3.13 Accounts Receivable	0	$ -	$
3.14 Cash Management	0	$ -	$
3.16 Procurement	0	$ -	$
3.17 Inventory	0	$ -	$
3.18 Fixed Assets	0	$ -	$
3.19 Job Costing	0	$ -	$
3.20 Capital Projects	0	$ -	$
Provisional Pricing			
3.15 HR and Payroll	0	$ -	
Totals - Integration Fees			$0.

(4) Training Fees	Year 1 Total Hours	Year 1 Hourly Rate	Total Year 1 T
Base FIS System Price	$ -	$ -	$
3.22 Training Requirements	$ -	$ -	$
3.23 Quality Assurance and Change Management	$ -	$ -	$
3.24 Ongoing Support Requirements	$ -	$ -	$
3.2.4 Customer Information System	$ -	$ -	$
3.2.5 Outage Management System	$ -	$ -	$
3.2.6 Work Force Management	$ -	$ -	$
3.2.7 Geographic Information System	$ -	$ -	$
3.2.8 3rd Party Interfaces	$ -	$ -	$
3.3 Hardware Specifications	$ -	$ -	$
3.5 Modules	$ -	$ -	$
3.6 Data Management	$ -	$ -	$
3.7 Security	$ -	$ -	$
3.8 Reporting	$ -	$ -	$
3.9 Business Intelligence	$ -	$ -	$
3.10 Workflow Automation	$ -	$ -	$
3.11 General Ledger	$ -	$ -	$

3.12 Accounts Payable	$ -	$ -	$
3.13 Accounts Receivable	$ -	$ -	$
3.14 Cash Management	$ -	$ -	$
3.16 Procurement	$ -	$ -	$
3.17 Inventory	$ -	$ -	$
3.18 Fixed Assets	$ -	$ -	$
3.19 Job Costing	$ -	$ -	$
3.20 Capital Projects	$ -	$ -	$
Provisional Pricing			
3.15 HR and Payroll			
Totals - Training Fees			**$**

(5) Pricing Confidence	
Level of Confidence in Pricing Submitted	0.00%
required to submit a level of confidence with the pricing they have provided (i.e. + / - 10%) or a statement of the pricing as a range. Include any key assumptions that have been made in developing the estimate and identify and factors that would cause the estimate to be altered.	

(6) Cost to Migrate from Hosted to License	**Price**
License Fees	$ -
Integration Fees	$ -
Other	$ -

Total Costs: Hosted Disaster Recovery FIS
$0.00
Total Costs = 10 years of Hosted fees, 10 years license fees, 1 year training, and all integration cost

Appendix C - Pricing Form (Schedule of Prices)

ancial Information System (FIS) Hosted Model Pricing for Disaster Recovery (DR) System

Total Year 1 Hosting Costs	Total Year 2 Hosting Costs	Total Year 3 Hosting Costs	Total Year 4 Hosting Costs	Total Year 5 Hosting Costs	Total Year 6 Hosting Costs	Total Year 7 Hosting Costs
$ -	$ -	$ -	$ -	$ -	$ -	$ -
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Total License Price	Year 1 Maintenance Price	Year 2 Maintenance Price	Year 3 Maintenance Price	Year 4 Maintenance Price	Year 5 Maintenance Price	Year 6 Maintenance Price
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raining Costs	On Going Total Hours	On Going Hourly Rate	Total On Going Training Costs
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Bidder Pricing Confidence Notes

Bidder Migration Notes

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Total Year 8 Hosting Costs	Total Year 9 Hosting Costs	Total Year 10 Hosting Costs	10 Year Total Hosting Costs
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Year 7 Maintenance Price	Year 8 Maintenance Price	Year 9 Maintenance Price	Year 10 Maintenance Price	Total Maintenance Costs
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ALTERNATE: Fin

(1) Pricing: License Model	Customer Base (electric meters)	Number of Users	Price Per Meter Per Month
Base FIS System Price	40,000	0	$ -
3.3 Hardware Specifications	40,000	0	$ -
3.5 Modules	40,000	0	$ -
3.6 Data Management	40,000	0	$ -
3.7 Security	40,000	0	$ -
3.8 Reporting	40,000	0	$ -
3.9 Business Intelligence	40,000	0	$ -
3.10 Workflow Automation	40,000	0	$ -
3.11 General Ledger	40,000	30	$ -
3.12 Accounts Payable	40,000	15	$ -
3.13 Accounts Receivable	40,000	15	$ -
3.14 Cash Management	40,000	20	$ -
3.16 Procurement	40,000	15	$ -
3.17 Inventory	40,000	20	$ -
3.18 Fixed Assets	40,000	15	$ -
3.19 Job Costing	40,000		$ -
3.20 Capital Projects	40,000	20	$ -
Provisional Pricing			
3.15 HR and Payroll	40,000	65	$ -
Totals - Pricing: License Model			$0.00

(2) Third Party License Requirements	Third Party Licenses Required	Price
Base FIS System Price		$ -
3.3 Hardware Specifications		$ -
3.5 Modules		$ -
3.6 Data Management		$ -
3.7 Security		$ -
3.8 Reporting		$ -
3.9 Business Intelligence		$ -
3.10 Workflow Automation		$ -
3.11 General Ledger		$ -
3.12 Accounts Payable		$ -
3.13 Accounts Receivable		$ -
3.14 Cash Management		$ -
3.16 Procurement		$ -
3.17 Inventory		$ -
3.18 Fixed Assets		$ -
3.19 Job Costing		$ -
3.20 Capital Projects		$ -
Provisional Pricing		
3.15 HR and Payroll		$ -
Totals - Third Party License Requirements		**$ -**

(3) Integration Fees	Total Hours	Hourly Rate	Total Imple /Integrati
Base FIS System Price	0	$ -	$
3.4 Integration of the FIS	0	$ -	$
3.4.1 Integration with the GIS	0	$ -	$
3.4.2 Integration with the CIS	0	$ -	$
3.4.3 Integration Methodology	0	$ -	$
3.4.4 Integration to other downstream systems	0	$ -	$
Integration to Workforce Management	0	$ -	$
Integration to Banking systems	0	$ -	$
Integration to Payroll data entry system	0	$ -	$
Integration to Inventory bar coding system	0	$ -	$
Enter additional integration item and cost	0	$ -	$
Enter additional integration item and cost	0	$ -	$
Enter additional integration item and cost	0	$ -	$
3.3 Hardware Specifications	0	$ -	$
3.5 Modules	0	$ -	$
3.6 Data Management	0	$ -	$
3.7 Security	0	$ -	$
3.8 Reporting	0	$ -	$
3.9 Business Intelligence	0	$ -	$
3.10 Workflow Automation	0	$ -	$
3.11 General Ledger	0	$ -	$
3.12 Accounts Payable	0	$ -	$
3.13 Accounts Receivable	0	$ -	$
3.14 Cash Management	0	$ -	$
3.16 Procurement	0	$ -	$
3.17 Inventory	0	$ -	$
3.18 Fixed Assets	0	$ -	$
3.19 Job Costing	0	$ -	$
3.20 Capital Projects	0	$ -	$
Provisional Pricing			
3.15 HR and Payroll	0	$ -	
Totals - Integration Fees			**$0.**

(4) Training Fees	Year 1 Total Hours	Year 1 Hourly Rate	Total Year 1 T
Base FIS System Price	$ -	$ -	$
3.22 Training Requirements	$ -	$ -	$
3.23 Quality Assurance and Change Management	$ -	$ -	$
3.24 Ongoing Support Requirements	$ -	$ -	$
3.2.4 Customer Information System	$ -	$ -	$
3.2.5 Outage Management System	$ -	$ -	$
3.2.6 Work Force Management	$ -	$ -	$
3.2.7 Geographic Information System	$ -	$ -	$
3.2.8 3rd Party Interfaces	$ -	$ -	$
3.3 Hardware Specifications	$ -	$ -	$
3.5 Modules	$ -	$ -	$
3.6 Data Management	$ -	$ -	$
3.7 Security	$ -	$ -	$
3.8 Reporting	$ -	$ -	$
3.9 Business Intelligence	$ -	$ -	$
3.10 Workflow Automation	$ -	$ -	$
3.11 General Ledger	$ -	$ -	$

3.12 Accounts Payable	$ -	$ -	$
3.13 Accounts Receivable	$ -	$ -	$
3.14 Cash Management	$ -	$ -	$
3.16 Procurement	$ -	$ -	$
3.17 Inventory	$ -	$ -	$
3.18 Fixed Assets	$ -	$ -	$
3.19 Job Costing	$ -	$ -	$
3.20 Capital Projects	$ -	$ -	$
Provisional Pricing			
3.15 HR and Payroll			
Totals - Training Fees			**$**

(5) Pricing Confidence	**Price**
Level of Confidence in Pricing Submitted	0.00%
required to submit a level of confidence with the pricing they have provided (i.e. + / - 10%) or a statement of the pricing as a range. Include any key assumptions that have been made in developing the estimate and identify and factors that would cause the estimate to be altered.	

(6) Cost to Migrate from Hosted to License	**Price**
License Fees	$ -
Integration Fees	$ -
Other	$ -

Total Costs: Licensed Production FIS
$0.00
Total Costs = 10 years of fees, 10 years license fees, 1 year training, and all integration costs

Appendix C - Pricing Form (Schedule of Prices)

ancial Information System (FIS) Licensed (on premise) Pricing for Production System

Total Year 1 Costs	Total Year 2 Costs	Total Year 3 Costs	Total Year 4 Costs	Total Year 5 Costs	Total Year 6 Costs	Total Year 7 Costs
$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -
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$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Total License Price	Year 1 Maintenance Price	Year 2 Maintenance Price	Year 3 Maintenance Price	Year 4 Maintenance Price	Year 5 Maintenance Price	Year 6 Maintenance Price
$ -	$ -	$ -	$ -	$ -	$ -	$ -
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raining Costs	On Going Total Hours	On Going Hourly Rate	Total On Going Training Costs
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Bidder Pricing Notes

Bidder Pricing Notes

Total Year 8 Costs	Total Year 9 Costs	Total Year 10 Costs	10 Year Total Costs
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Year 7 Maintenance Price	Year 8 Maintenance Price	Year 9 Maintenance Price	Year 10 Maintenance Price	Total Maintenance Costs
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ALTERNATE:			
(1) Pricing: License Model	Customer Base (electric meters)	Number of Users	Price Per Meter Per Month
Base FIS System Price	40,000	0	$ -
3.3 Hardware Specifications	40,000	0	$ -
3.5 Modules	40,000	0	$ -
3.6 Data Management	40,000	0	$ -
3.7 Security	40,000	0	$ -
3.8 Reporting	40,000	0	$ -
3.9 Business Intelligence	40,000	0	$ -
3.10 Workflow Automation	40,000	0	$ -
3.11 General Ledger	40,000	30	$ -
3.12 Accounts Payable	40,000	15	$ -
3.13 Accounts Receivable	40,000	15	$ -
3.14 Cash Management	40,000	20	$ -
3.16 Procurement	40,000	15	$ -
3.17 Inventory	40,000	20	$ -
3.18 Fixed Assets	40,000	15	$ -
3.19 Job Costing	40,000		$ -
3.20 Capital Projects	40,000	20	$ -
Provisional Pricing			
3.15 HR and Payroll	40,000	65	$ -
Totals - Pricing: License Model			$0.00

(2) Third Party License Requirements	Third Party Licenses Required	Price
Base FIS System Price		$ -
3.3 Hardware Specifications		$ -
3.5 Modules		$ -
3.6 Data Management		$ -
3.7 Security		$ -
3.8 Reporting		$ -
3.9 Business Intelligence		$ -
3.10 Workflow Automation		$ -
3.11 General Ledger		$ -
3.12 Accounts Payable		$ -
3.13 Accounts Receivable		$ -
3.14 Cash Management		$ -
3.16 Procurement		$ -
3.17 Inventory		$ -
3.18 Fixed Assets		$ -
3.19 Job Costing		$ -
3.20 Capital Projects		$ -
Provisional Pricing		
3.15 HR and Payroll		$ -
Totals - Third Party License Requirements		**$ -**

(3) Integration Fees	Total Hours	Hourly Rate	Total Imple /Integrati
Base FIS System Price	0	$ -	$
3.4 Integration of the FIS	0	$ -	$
3.4.1 Integration with the GIS	0	$ -	$
3.4.2 Integration with the CIS	0	$ -	$
3.4.3 Integration Methodology	0	$ -	$
3.4.4 Integration to other downstream systems	0	$ -	$
Integration to Workforce Management	0	$ -	$
Integration to Banking systems	0	$ -	$
Integration to Payroll data entry system	0	$ -	$
Integration to Inventory bar coding system	0	$ -	$
Enter additional integration item and cost	0	$ -	$
Enter additional integration item and cost	0	$ -	$
Enter additional integration item and cost	0	$ -	$
3.3 Hardware Specifications	0	$ -	$
3.5 Modules	0	$ -	$
3.6 Data Management	0	$ -	$
3.7 Security	0	$ -	$
3.8 Reporting	0	$ -	$
3.9 Business Intelligence	0	$ -	$
3.10 Workflow Automation	0	$ -	$
3.11 General Ledger	0	$ -	$
3.12 Accounts Payable	0	$ -	$
3.13 Accounts Receivable	0	$ -	$
3.14 Cash Management	0	$ -	$
3.16 Procurement	0	$ -	$
3.17 Inventory	0	$ -	$
3.18 Fixed Assets	0	$ -	$
3.19 Job Costing	0	$ -	$
3.20 Capital Projects	0	$ -	$
Provisional Pricing			
3.15 HR and Payroll	0	$ -	
Totals - Integration Fees			**$0.**

(4) Training Fees	Year 1 Total Hours	Year 1 Hourly Rate	Total Year 1 T
Base FIS System Price	$ -	$ -	$
3.22 Training Requirements	$ -	$ -	$
3.23 Quality Assurance and Change Management	$ -	$ -	$
3.24 Ongoing Support Requirements	$ -	$ -	$
3.2.4 Customer Information System	$ -	$ -	$
3.2.5 Outage Management System	$ -	$ -	$
3.2.6 Work Force Management	$ -	$ -	$
3.2.7 Geographic Information System	$ -	$ -	$
3.2.8 3rd Party Interfaces	$ -	$ -	$
3.3 Hardware Specifications	$ -	$ -	$
3.5 Modules	$ -	$ -	$
3.6 Data Management	$ -	$ -	$
3.7 Security	$ -	$ -	$
3.8 Reporting	$ -	$ -	$
3.9 Business Intelligence	$ -	$ -	$
3.10 Workflow Automation	$ -	$ -	$
3.11 General Ledger	$ -	$ -	$

3.12 Accounts Payable	$ -	$ -	$
3.13 Accounts Receivable	$ -	$ -	$
3.14 Cash Management	$ -	$ -	$
3.16 Procurement	$ -	$ -	$
3.17 Inventory	$ -	$ -	$
3.18 Fixed Assets	$ -	$ -	$
3.19 Job Costing	$ -	$ -	$
3.20 Capital Projects	$ -	$ -	$
Provisional Pricing			
3.15 HR and Payroll			
Totals - Training Fees			**$**

(5) Pricing Confidence	Price
Level of Confidence in Pricing Submitted	0.00%
required to submit a level of confidence with the pricing they have provided (i.e. + / - 10%) or a statement of the pricing as a range. Include any key assumptions that have been made in developing the estimate and identify and factors that would cause the estimate to be altered.	

Total Costs: Licensed Test FIS
$0.00
Total Costs = 10 years of fees, 10 years license fees, 1 year training, and all integration costs

Appendix C - Pricing Form (Schedule of Prices)

Financial Information System (FIS) Licensed (on premise) Pricing for Test System

Total Year 1 Costs	Total Year 2 Costs	Total Year 3 Costs	Total Year 4 Costs	Total Year 5 Costs	Total Year 6 Costs	Total Year 7 Costs
$ -	$ -	$ -	$ -	$ -	$ -	$ -
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$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Total License Price	Year 1 Maintenance Price	Year 2 Maintenance Price	Year 3 Maintenance Price	Year 4 Maintenance Price	Year 5 Maintenance Price	Year 6 Maintenance Price
$ -	$ -	$ -	$ -	$ -	$ -	$ -
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raining Costs	On Going Total Hours	On Going Hourly Rate	Total On Going Training Costs
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Bidder Pricing Notes

Total Year 8 Costs	Total Year 9 Costs	Total Year 10 Costs	10 Year Total Costs
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Year 7 Maintenance Price	Year 8 Maintenance Price	Year 9 Maintenance Price	Year 10 Maintenance Price	Total Maintenance Costs
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ALTERNATE: Financial

(1) Pricing: License Model	Customer	Number of	Price Per
Base FIS System Price	40,000	0	$ -
3.3 Hardware Specifications	40,000	0	$ -
3.5 Modules	40,000	0	$ -
3.6 Data Management	40,000	0	$ -
3.7 Security	40,000	0	$ -
3.8 Reporting	40,000	0	$ -
3.9 Business Intelligence	40,000	0	$ -
3.10 Workflow Automation	40,000	0	$ -
3.11 General Ledger	40,000	30	$ -
3.12 Accounts Payable	40,000	15	$ -
3.13 Accounts Receivable	40,000	15	$ -
3.14 Cash Management	40,000	20	$ -
3.16 Procurement	40,000	15	$ -
3.17 Inventory	40,000	20	$ -
3.18 Fixed Assets	40,000	15	$ -
3.19 Job Costing	40,000		$ -
3.20 Capital Projects	40,000	20	$ -
Provisional Pricing			
3.15 HR and Payroll	40,000	65	$ -
Totals - Pricing: License Model			$0.00

(2) Third Party License Requirements	Third Party Licenses		Price
Base FIS System Price			$ -
3.3 Hardware Specifications			$ -
3.5 Modules			$ -
3.6 Data Management			$ -
3.7 Security			$ -
3.8 Reporting			$ -
3.9 Business Intelligence			$ -
3.10 Workflow Automation			$ -
3.11 General Ledger			$ -
3.12 Accounts Payable			$ -
3.13 Accounts Receivable			$ -
3.14 Cash Management			$ -
3.16 Procurement			$ -
3.17 Inventory			$ -
3.18 Fixed Assets			$ -
3.19 Job Costing			
3.20 Capital Projects			$ -
Provisional Pricing			
3.15 HR and Payroll			$ -
Totals - Third Party License Requirements			$ -

(3) Integration Fees	Total Hours	Hourly Rate	Total Imple
Base FIS System Price	0	$ -	$
3.4 Integration of the FIS	0	$ -	$
3.4.1 Integration with the GIS	0	$ -	$
3.4.2 Integration with the CIS	0	$ -	$
3.4.3 Integration Methodology	0	$ -	$
3.4.4 Integration to other downstream systems	0	$ -	$
Integration to Workforce Management	0	$ -	$

Integration to Banking systems	0	$ -	$
Integration to Payroll data entry system	0	$ -	$
Integration to Inventory bar coding system	0	$ -	$
Enter additional integration item and cost	0	$ -	$
Enter additional integration item and cost	0	$ -	$
Enter additional integration item and cost	0	$ -	$
3.3 Hardware Specifications	0	$ -	$
3.5 Modules	0	$ -	$
3.6 Data Management	0	$ -	$
3.7 Security	0	$ -	$
3.8 Reporting	0	$ -	$
3.9 Business Intelligence	0	$ -	$
3.10 Workflow Automation	0	$ -	$
3.11 General Ledger	0	$ -	$
3.12 Accounts Payable	0	$ -	$
3.13 Accounts Receivable	0	$ -	$
3.14 Cash Management	0	$ -	$
3.16 Procurement	0	$ -	$
3.17 Inventory	0	$ -	$
3.18 Fixed Assets	0	$ -	$
3.19 Job Costing			
3.20 Capital Projects	0	$ -	$
Provisional Pricing			
3.15 HR and Payroll	0	$ -	
Totals - Integration Fees			**$0.**

(4) Training Fees	Year 1 Total	Year 1 Hourly	Total Year 1 T
Base FIS System Price	$ -	$ -	$
3.22 Training Requirements	$ -	$ -	$
3.23 Quality Assurance and Change Management	$ -	$ -	$
3.24 Ongoing Support Requirements	$ -	$ -	$
3.2.4 Customer Information System	$ -	$ -	$
3.2.5 Outage Management System	$ -	$ -	$
3.2.6 Work Force Management	$ -	$ -	$
3.2.7 Geographic Information System	$ -	$ -	$
3.2.8 3rd Party Interfaces	$ -	$ -	$
3.3 Hardware Specifications	$ -	$ -	$
3.5 Modules	$ -	$ -	$
3.6 Data Management	$ -	$ -	$
3.7 Security	$ -	$ -	$
3.8 Reporting	$ -	$ -	$
3.9 Business Intelligence	$ -	$ -	$
3.10 Workflow Automation	$ -	$ -	$
3.11 General Ledger	$ -	$ -	$
3.12 Accounts Payable	$ -	$ -	$
3.13 Accounts Receivable	$ -	$ -	$
3.14 Cash Management	$ -	$ -	$
3.16 Procurement	$ -	$ -	$
3.17 Inventory	$ -	$ -	$
3.18 Fixed Assets	$ -	$ -	$
3.19 Job Costing			
3.20 Capital Projects	$ -	$ -	$
Provisional Pricing			
3.15 HR and Payroll			
Totals - Training Fees			**$**

(5) Pricing Confidence	Price
Level of Confidence in Pricing Submitted	0.00%

required to submit a level of confidence with the pricing they have provided (i.e. + / - 10%) or a statement of the pricing as a range. Include any key assumptions that have been made in developing the estimate and identify and factors that would cause the estimate to be altered.			

Total Costs: Licensed Disaster Recovery FIS
$0.00
Total Costs = 10 years of fees, 10 years license fees, 1 year training, and all integration costs

Appendix C - Pricing Form (Schedule of Prices)

Information System (FIS) Licensed (on premise) Pricing for Disaster Recovery (DR) System

Total Year 1	Total Year 2	Total Year 3	Total Year 4	Total Year 5	Total Year 6	Total Year 7
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Total License	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6
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raining Costs	On Going	On Going	Total On Going Training
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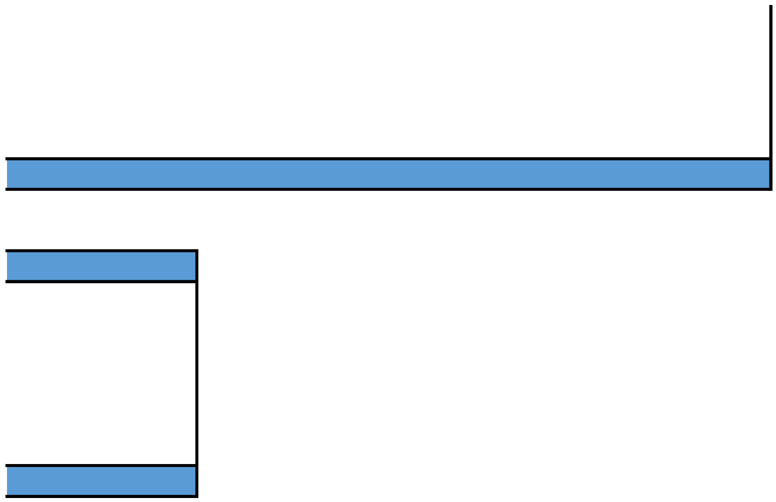
Bidder Pricing Notes



Total Year 8	Total Year 9	Total Year 10	10 Year Total Costs
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Year 7	Year 8	Year 9	Year 10	Total
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Functional Requirements Workbook

Priority Requirements

C	Critical, proposals may be disqualified if several of these requirements not met
V	Required Very Important, System Severely limited or compromised
I	Important, preferred solution should have these
N	Nice to Have, moderately important
O	Optional. Least Important, but system would benefit

Solution Classification

Core	Functionality resides in basic FIS
Client Configure	Functionality is available to clients to configure
Optional	Functionality not available in basic FIS but would be available as an upgrade or add-on
Pending	Planned functionality not yet available but will be in near future - indicate if it will be Core or Optional
N/A	Not presently available and not planned for near future

I HUMAN RESOURCES/PAYROLL

General Requirements		Priority	Solution	Comments
HR 1.1	Employee master file maintained with proper authorization	C		
HR 1.2	Restrict access to confidential information	C		
HR 1.3	System maintains employee banks (ie, sick, overtime, vacation, etc)	V		
HR 1.4	System able to reflect pay rate changes mid payroll period	C		
HR 1.5	System able to reflect pay rate differences within pay period (ie shift premiums)	C		
HR 1.6	System can set employees as inactive and reinstate if return	I		
HR 1.7	System can track employees by:			
HR 1.7.1	Department	C		
HR 1.7.2	Entity	C		
HR 1.7.3	Union group	C		
HR 1.7.4	Management level	C		
HR.1.8	System can easily transfer employees from one position or entity to another	I		
HR 1.9	System can have more than one employee in specific positions (eg Financial Analyst)	V		
HR 1.10	System can easily integrate with external systems	I		
HR 1.11	Employee records include fields for:			
HR 1.11.1	Name	C		
HR 1.11.2	Address	C		
HR 1.11.3	Multiple phone numbers	V		
HR 1.11.4	Social Insurance Number	C		
HR 1.11.5	Sex	C		
HR 1.11.6	Emergency contact information	V		

I	HUMAN RESOURCES/PAYROLL	Priority	Solution	Comments
HR 1.11.7	Marital status	V		
HR 1.11.8	Marital status for benefit administration	V		
HR 1.11.9	Position	V		
HR 1.11.10	Department	V		
HR 1.11.11	Photo	N		
HR 1.11.12	Hire Date	C		
HR 1.11.13	Termination Date	V		
HR 1.11.14	Reason for termination	V		
HR 1.11.15	Supervisor (current and previous)	I		
HR 1.11.16	User defined fields	I		
HR 1.12	System can mass update salaries and wages at the group level based on agreed upon annual increases	V		
HR 1.13	System supports various leave of absence types	V		
Transaction Processing				
HR 2.1	Employees payroll uploaded directly to bank	C		
HR 2.2	Calculation of payroll remittances (ie, CRA source deductions, EHT, WSIB, OMERS)	V		
HR 2.3	System able to transfer payroll remittances to AP module	V		
HR 2.4	System generates electronic payslips	C		
HR 2.5	Time and attendance tracking can be done to track:			
HR 2.5.1	Equipment used	V		
HR 2.5.2	Overtime banked or taken	V		
HR 2.5.3	Sick time taken by nature:			
HR 2.5.3.1	Employee	V		
HR 2.5.3.2	Family	V		
HR 2.5.3.3	Doctor's appointment	V		
HR 2.5.3.4	WSIB	V		
HR 2.5.3.5	Unpaid sick leave	V		
HR 2.5.4	Employees can assign hours to projects	V		
HR 2.6	System can track reimbursements (eg licenses, professional dues, uniforms, etc)	I		
HR 2.7	System can track training details including cost	I		
HR 2.8	System can track employee interest free loans and calculate related taxable benefits	V		
HR 2.9	Benefit costs tracked by employee by type (eg CPP, EI, EHT, WSIB, Extended Health, Dental, etc)	V		
HR 2.10	Accruals calculated and recorded when period end falls during pay period	I		
HR 2.11	Employees enter and submit their time electronically	V		

I	HUMAN RESOURCES/PAYROLL	Priority	Solution	Comments
HR 2.12	Managers/Supervisors are able to review and approve time entries electronically	V		
HR 2.13	Preliminary payroll results can be reviewed and approved prior to processing	C		
Inquiry and Reporting				
HR 3.1	System able to issue T4 slips and summaries	V		
HR 3.2	System issues report for source deduction remittances	V		
HR 3.3	System provides reports detailing:			
HR 3.3.1	Various banks by employee/department	V		
HR 3.3.2	Overtime by employee/department	V		
HR 3.3.3	Sick time taken by employee/department	V		
HR 3.4	Accurate forecasting of labour-related costs and "what if" analysis	I		
HR 3.5	System generated graphical organization charts	N		
HR 3.6	Accident and injury reporting and analysis can be done within the system	N		
HR 3.7	Complaint and grievance tracking and analysis can be done within the system	N		
HR 3.8	System can track compentency goals established with supervisor during evaluation or other process	N		
HR 3.9	System can track performance reviews	N		
HR 3.10	System allows free form notes to be added to employee files tracked in chronological order	I		
HR 3.11	Track disciplinary actions by:			
HR 3.11.1	Date	N		
HR 3.11.2	Type:			
HR 3.11.2.1	Oral	N		
HR 3.11.2.2	Written warning	N		
HR 3.11.2.3	Disciplinary time-off	N		
HR 3.11.2.4	Suspension	N		
HR 3.11.2.5	Dismissal	N		
HR 3.11.2.6	Demotion	N		
HR 3.11.3	Performance plan	N		

Instructions	Overview:

Functional Requirements Workbook

Proponents will note some duplication in the content that is covered within both the functional workbook and the technical questions found in Section 3. This is intentional on behalf of BPI, as the nature of the questions differs between the two sources of information. The "scope" of the questions in the functional workbook is broad in nature and allows BPI to gather a great deal of information, however the nature of the workbook does not allow for a deep understanding of the system. The nature of the questions within Section 3 will allow for a greater depth of understanding of the proposed solution given that the technical questions require the vendor to provide more detailed information including such things as a description of the intended business process, and screen shots of the proposed solution so that BPI can begin to understand the "look and feel" of the
a "Priority Requirements" section at the top of each tab that explains the indicators used in the tables. At the top of each tab there is also a "Solution Classification" table which provides the proponents with an indicator that they will use to complete the functional requirements tables/questions. Proponents must enter a "Solution Classification" into the "Solution" column that accurately describes the proposed solution's ability to fulfill the functional requirement.
For example, on the General Ledger tab, functional requirement "GL 1.1" asks whether the "System accommodates multiple ledgers". In response to the functional requirement, the Proponent would enter "Core", "Client Configure", "Optional", "Pending" or "NA" based on their system's current functionality.
encouraged to enter additional information where the indication is that the functional requirement is not considered a "Core" part of the system. For example, optional items might include comments pertaining to the cost, or the process to upgrade, pending items might include comments pertaining to anticipated delivery timelines, etc.

Functional Requirements Workbook

Priority Requirements

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V	Required Very Important, System Severely limited or compromised
I	Important, preferred solution should have these
N	Nice to Have, moderately important
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A GENERAL LEDGER (GL)

		Priority	Solution	Comments
General Requirements				
GL 1.1	System accommodates multiple ledgers	C		
GL 1.2	System able to perform consolidations	V		
GL 1.3	System supports use of multiple fiscal years	C		
GL 1.4	System supports use of multiple fiscal periods	C		
GL 1.5	System accommodates non-calendar based fiscal years	N		
GL 1.6	System provides warnings or alerts for available funds checking for non-budgeted accounts	N		
GL 1.7	System allows drill down from summary account totals to the detailed transactions and original source document(s)	V		
Chart of Accounts (COA) Design				
GL 2.1	COA allows for at least 7 alphanumeric characters	V		
GL 2.2	System allows accounts to be set as active (available for posting) or inactive (not available for posting)	I		
GL 2.3	New accounts can be created by copying structure information from an existing account or from a model with appropriate security	I		
GL 2.4	Account structure is flexible to support corporate reorganizations and future growth	V		
GL 2.5	System will allow creation of multiple control accounts (receivable and payable)	V		
GL 2.6	Accounts can be designated by either assets, liabilities, equity, revenue or expenditure	N		
GL 2.7	System allows creation of non-financial statistical accounts	V		
Journal Entry and Batch Processing				
GL 3.1	System automatically generates sequential journal voucher numbers	C		
GL 3.2	System allows batch posting for journal entries	I		
GL 3.3	System will not allow transactions to post until all "required" fields are completed	C		
GL 3.4	System supports recurring journal entries with varying dollar amounts or accounts	I		
GL 3.5	System will allow for journal entry to remain unposted to be posted at a later time	I		

A	GENERAL LEDGER (GL)	Priority	Solution	Comments
GL 3.6	System requires all journal entries balance prior to posting	C		
GL 3.7	System allows ample remark field to provide explanation of purpose of journal entry. Please provide details of any limitations	I		
GL 3.8	System will automatically create due to/from entries for inter-company transactions	C		
Period Closing and Year End				
GL 4.1	System allows more than one period open	I		
GL 4.2	System allows more than one fiscal year open	I		
GL 4.3	System allows entries to future periods	I		
GL 4.4	System calculates and accrues payroll at year end	N		
GL 4.5	System supports the auto-reversal of transactions for the completion of accruals	I		
Inquiry and Reporting				
GL 5.1	System allows suppression of zero balance accounts at the user request	N		
GL 5.2	System produces monthly HST reporting	N		
GL 5.3	System allows reports to be directly downloaded to Excel	I		
GL 5.4	System allows reporting on any portion of the account code structure and has the ability to run reports for non-sequential accounts	V		
GL 5.5	System allows for rounding of numbers for reporting purposes (ie nearest thousand)	N		
GL 5.6	System produces reports for open batches by module	I		

Functional Requirements Workbook

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B BUDGET

		Priority	Solution	Comments
General Requirements				
BU 1.1	Budget module uses the primary system's COA including statistical accounts	C		
BU 1.2	System accommodates multiple budget cycles (ie monthly, annual, forecast)	V		
BU 1.3	System supports multi-year budgeting	V		
BU 1.4	System maintains multiple budget versions (ie consolidated, departmental)	I		
BU 1.5	System has a user controlled "lock/unlock" feature for each budget version	I		
BU 1.6	System supports budgetary allotments by month, quarter, year or any other period defined by user	I		
BU 1.7	System allows all budget amounts to be rounded based on user-defined parameters	N		
Budget Control and Preparation				
BU 2.1	System assembles multiple years of budget information for budget preparation	I		
BU 2.2	System allows use of standard templates and style sheets	N		
BU 2.3	System able to copy budgets from one cycle to another	N		
BU 2.4	System able to drill down from any field within the budget entry screen	I		
BU 2.5	System permits users to view prior year line-item budget while entering new budget	I		
BU 2.6	System permits users to view current year-to-date line-item budget while entering forecasts	I		
BU 2.7	System able to prevent users from updating budget data after a specific cut-off date	V		
BU 2.8	System able to indicate one-time expenditures in the budget issues by line item	I		
BU 2.9	System able to roll up budget worksheets into master budget at various user-defined levels	C		

B	BUDGET		Priority	Solution	Comments
	BU 2.10	System able to apply a percentage, fixed amount or other formula to a budget figure on a line-by-line basis	I		
	Inquiry and Reporting				
	BU 3.1	System accommodates inquiry based on keyword search	N		
	BU 3.2	System provides multi-year budgetary reports online and printed, in detail or summary	V		

Functional Requirements Workbook

Priority Requirements

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C ACCOUNTS RECEIVABLE

		Priority	Solution	Comments
General Requirements				
AR 1.2	System supports electronic fund transfers (EFT) for customer payments (credit balances)	V		
AR 1.3	System able to electronically invoice customers	I		
AR 1.4	System able to send electronic monthly statements to customers	I		
AR 1.5	System allows customers to access their account and invoice information on web via customer self service	N		
AR 1.6	System automatically applies interest and penalties based upon user-defined rules or criteria	C		
AR 1.7	System alerts proper contacts for NSF cheques	I		
AR 1.8	System able to have multiple periods open simultaneously	I		
AR 1.9	System able to attach any type of electronic files to data entry transactions	V		
AR 1.10	System provides the ability to recognize or accommodate:			
AR 1.10.1	Revenue earned and billed	C		
AR 1.10.2	Revenue earned, but not yet billed	V		
AR 1.10.3	Deferred revenue	V		
AR 1.10.4	Estimated revenue	N		
Customer Records				
AR 2.1	System supports the ability to maintain customer master file	C		
AR 2.2	System prevents duplicate customer numbers	C		
AR 2.3	System warns if customer maintenance indicates the potential for duplicate customers	I		
AR 2.4	System allows multiple customer names	I		
AR 2.5	System supports parent/child relationship for customer records	I		
AR 2.6	System records the following customer information:			
AR 2.6.1	Balance forward or open items	V		
AR 2.6.2	Multiple contact names	N		
AR 2.6.3	Multiple phone numbers	N		
AR 2.6.4	Multiple addresses	N		
AR 2.6.5	Multiple email addresses	N		
AR 2.6.6	Social Insurance Number or Business Number	N		

C	ACCOUNTS RECEIVABLE	Priority	Solution	Comments
AR 2.6.7	Current and unpaid late payment penalty and interest charges	I		
AR 2.6.8	Balance due	V		
AR 2.6.9	Last payment amount and date of payment	I		
AR 2.6.10	Year-to-date payments	I		
AR 2.6.11	Number of times past due by user-defined periods	N		
AR 2.6.12	Highest past due balance	N		
AR 2.6.13	Highest outstanding balance	N		
AR 2.6.14	Average number of days to pay	I		
AR 2.6.15	Payments returned by bank	I		
AR 2.6.16	Bankruptcy data	N		
AR 2.6.17	Notes/comments	I		
AR 2.6.18	Link to vendor file (if customer is also a vendor)	N		
AR 2.6.19	Link to payroll file (if customer is also an employee)	N		
AR 2.6.20	Other user defined fields	N		
AR 2.6.21	Date customer was added	N		
AR 2.7	System allows multiple user defined customer classifications	I		
AR 2.8	System generates messages for automatic display on specific dates for follow-up with a customer	N		
AR 2.9	System accommodates payment plans	I		
Invoices				
AR 3.1	System accommodates recurring invoices	C		
AR 3.2	System allows adjustments to penalties and fees applied to invoices with proper authority	V		
AR 3.3	System accommodates different billing rates for internal and external customers	N		
AR 3.4	System includes the billing date range and/or period on invoices	V		
AR 3.5	System supports sending invoices to multiple addresses for the same customer	N		
AR 3.6	System generates account statements for the following:			
AR 3.6.1	Specific account types	I		
AR 3.6.2	Specific entities	N		
AR 3.6.3	Range of accounts within a department	N		
AR 3.6.4	Range of customers or individual customers	N		
AR 3.6.5	Delinquent accounts	I		
AR 3.6.6	Other user defined criteria	N		
AR 3.7	System generates consolidated statements for customers with multiple accounts	I		
AR 3.8	System maintains detail of unbilled charges	I		
AR 3.9	System accommodates easy correction and replacement of the original invoice	I		
AR 3.10	System allows users to write-off small discrepancies between the amount due and the amount received with proper security	I		
AR 3.11	System provides ability to calculate and include various taxes on invoices	C		
AR 3.12	System provides ability to print individual statements on demand or automatically during a desired cycle	V		

C	ACCOUNTS RECEIVABLE	Priority	Solution	Comments
AR 3.13	System allows credit memos, with appropriate security	V		
AR 3.14	System allows pre-payment postings	I		
AR 3.15	System allows printing standardized comments on billing documents (individual and group basis)	I		
AR 3.16	System can apply payments against a receivable generated through Accounts Payable	I		
Receipts				
AR 4.1	System accommodates the following transactions for payment:			
AR 4.1.1	Electronic fund transfer (EFT)	I		
AR 4.1.2	Lockbox	N		
AR 4.1.3	Credit card	I		
AR 4.14	Debit card	I		
AR 4.1.5	Payment through website	I		
AR 4.1.6	Direct debit	I		
AR 4.1.7	Cash	I		
AR 4.1.8	Cheque	I		
AR 4.1.9	Money order	N		
AR 4.1.10	Other electronic receipts	I		
AR 4.2	System able to generate cash receipt on demand	I		
AR 4.3	System accommodates following information on cash receipt:			
AR 4.3.1	Amount	V		
AR 4.3.2	Transaction number	V		
AR 4.3.3	Transaction type	V		
AR 4.3.4	Customer name	V		
AR 4.3.5	Customer account number	V		
AR 4.3.6	Customer address	I		
AR 4.3.7	Date of service	I		
AR 4.3.8	Current date	C		
AR 4.3.9	User processing the payment	N		
AR 4.3.10	Quantity	N		
AR 4.3.11	Amount of taxes	N		
AR 4.3.12	Tender type	I		
AR 4.3.13	Description of service	N		
AR 4.3.14	Other user-defined fields	N		
AR 4.4	System captures transactions for revenue and redemption purchases (ie inventory, services, other)	I		
AR 4.5	System accommodates multiple payments for an invoice and direct payment portion to appropriate GL account	I		
Collections				
AR 5.1	System generates aging analysis of outstanding AR	C		
AR 5.2	System able to track amounts collected, collection cases and results of the collection effort	V		
Inquiry and Reporting				
AR 6.1	System generates reports by user/department/category for:			
AR 6.1.1	Aging reports with user-defined aging categories	C		
AR 6.1.2	Cash register journals	V		

C	ACCOUNTS RECEIVABLE	Priority	Solution	Comments
AR 6.1.3	Daily bank deposits and direct deposit payments processed electronically	V		
AR 6.2	System reports receivables written-off	V		
AR 6.3	System reports revenue and receivable by type	V		
AR 6.4	System provides reports to support revenue forecasting	I		
AR 6.5	System produces reconciliation statements for bank accounts	V		

Functional Requirements Workbook

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D ACCOUNTS PAYABLE

		Priority	Solution	Comments
General Requirements				
AP 1.1	System able to process AP transactions in real-time	C		
AP 1.2	System allows inquiry of accounts balances and transaction details, including pre-encumbrances, encumbrances and expenditures	V		
AP 1.3	Provide inquires by department, company or project	V		
AP 1.4	System allows direct allocation to multiple GL accounts using amount or percentage	V		
AP 1.5	System validates transactions including:			
AP 1.5.1	Vendor number	C		
AP 1.5.2	Department or entity	V		
AP 1.5.3	Transaction date (open period)	C		
AP 1.5.4	Account number	C		
AP 1.5.5	Distinct invoice number (verify not already entered)	V		
AP 1.5.6	Due date if entered	I		
AP 1.5.7	Purchase order is valid and open	V		
AP 1.5.8	Job or project number is valid and open	V		
AP 1.5.9	Tax codes	V		
AP 1.6	System accommodates electronic payments	C		
Invoices and Vouchers				
AP 2.1	System processes multiple partial payments with different due dates while maintaining the appropriate unpaid balance as an open invoice	V		
AP 2.2	System processes one-time payments to a vendor, with the proper level of authorization, without adding a vendor to the master file	I		
AP 2.3	System allows withholding portions of an invoice from payment, such as contract retainages or for partial acceptance of goods based on either a percentage or a dollar amount	I		
AP 2.4	System maintains a subsidiary ledger of all retainage balance by vendor and invoice	I		
AP 2.5	System provides the ability to schedule vendor payments based on the following methods:			
AP 2.5.1	Vendor payment terms defaulted from vendor master file	V		

D	ACCOUNTS PAYABLE	Priority	Solution	Comments
AP 2.5.2	Payment discount terms specified on the purchase order	V		
AP 2.5.3	On-line entry payment due date	V		
AP 2.5.4	Manual override of payment date to expedite payment with proper security	V		
AP 2.6	System able to enter invoices in batches with batch totals for control purposes	I		
AP 2.7	System able to look up account numbers and vendors without leaving the transaction entry	I		
AP 2.8	System tracks and reports discounts taken and discounts lost	I		
AP 2.9	System able to process "credit" invoices	V		
AP 2.10	System displays remaining amount left on PO when entering voucher against the PO	I		
AP 2.11	System able to create invoices automatically from information received from an external system (ie credit refunds from Customer Information System)	V		
AP 2.12	System provides multiple cash accounts to be used for payment of vouchers	V		
Document Matching				
AP 3.1	System able to accept multiple invoices and multiple receiving documents per single PO	V		
Vendors				
AP 4.1	System maintains a common vendor file between the purchasing and AP modules	C		
AP 4.2	System provides an alpha search and on-line display capability of the vendor name	V		
AP 4.3	System able to enter notes and comments associated with the vendor master record	I		
AP 4.4	System to provide ability to indicate vendor tax status (HST, US Vendor or HST exempt)	V		
AP 4.5	Provide alerts/warnings about vendor insurance expiration with user-defined criteria	N		
AP 4.6	Allow for Vendor mass maintenance (i.e., default tax code)	I		
Payments and Authorization				
AP 5.1	Provide the ability to enter invoices pending management approval at a future date	C		
AP 5.2	Allow entry of the terms of a recurring payment and automatically produce cheques and accounting transactions to satisfy these obligations. Do not require entry of separate invoices for these payments	N		
AP 5.3	Allow issuance of recurring payments based on user-defined tables, with respect to payment dates	I		
AP 5.4	Allow individual on-line notification and approval of recurring payments prior to processing, at the user's option	I		
AP 5.5	Allow payment of multiple claims/vouchers or invoices to a single vendor with a single cheque, at the user's option	C		

D ACCOUNTS PAYABLE		Priority	Solution	Comments
AP 5.6	Allow payment of a single claim/voucher to a single vendor with a single cheque where multiple claims exist	C		
AP 5.7	Provide the ability to suppress printing negative or zero-amount cheques	V		
AP 5.8	Process cheques (computer and manual), electronic funds transfers, drafts, etc., monthly, weekly, biweekly, daily, and on demand	V		
AP 5.9	Print a list of items to be paid for user review, prior to generating and recording the actual payment	V		
AP 5.10	Provide for user-defined cheque and cheque-stub/remittance advice formats	V		
AP 5.11	Provide the ability to reference individual voucher number, invoice number, and each invoice amount on the cheque "stub"	V		
AP 5.12	Provide the ability to print laser-printed cheques with magnetic ink coding	V		
AP 5.13	Provide the ability to indicate a cheque as a "reissue cheque"	N		
AP 5.14	Provide the ability to designate cheques for "special handling" (i.e. pick-up)	I		
AP 5.15	Provide the ability to cross-reference a reissued cheque to a previously voided cheque	N		
AP 5.16	Provide the ability to restart a cheque run in order to recover from a failure (e.g., printer jam)	V		
AP 5.17	Provide the option to use either pre-printed cheque numbers or to use machine-assigned cheque numbers	I		
AP 5.18	Provide ability to automatically generate HST and HST rebate (or GST, PST and other taxes)	N		
Expense Reports & Travel Authorization				
AP 6.1	Prepare advance payments through a direct payment process with appropriate payment due dates	N		
AP 6.2	Link direct payment advances, direct payment registration and other direct payment actions to the travel authorization	N		
AP 6.3	Provide the linkages to enable the imaging or scanning of travel receipts (lodging, car rental, taxi/shuttle, etc) into the system and link to the travel expense report for expense justification	N		
AP 6.4	Link travel expense reports to the travel authorization	N		
AP 6.5	Provide comment section for notes regarding problems or other issues associated with travel	N		
AP 6.6	Provide for ad hoc report preparation for travel audit needs	N		
AP 6.7	Provide the capability in the system to clear reported travel expenses against travel advances without issuing a zero amount cheque	N		
AP 6.8	System should allow claimant to directly enter claim in the system	N		
Cheque Reconciliation				
AP 7.1	Provide the ability to input and process bank reconciliation items (e.g., cleared cheques) from bank-supplied tape or other media	V		

D	ACCOUNTS PAYABLE	Priority	Solution	Comments
AP 7.2	Maintain cheque information such as cheque number, payee name, date, status (outstanding, original, cancelled, outstanding reinstated, redeemed), amount, entity, and bank account	V		
AP 7.3	Enter corrections, adjustments, cancellations, redemptions, and reinstatements on-line	I		
AP 7.4	Provide an error suspense mechanism for rejected cheque reconciliation transactions	I		
AP 7.5	Provide on-line inquiry capabilities to all cheque information by fund and cheque number, including status of cheque and date of activity	I		
AP 7.6	Maintain a table of user-defined cheque status values to include:			
AP 7.6.1	Outstanding	I		
AP 7.6.2	Cleared	I		
AP 7.6.3	Stop payment	I		
AP 7.6.4	Stop payment and void	I		
AP 7.6.5	Returned	I		
AP 7.6.6	Void and reissue	I		
AP 7.6.7	Void no reissue	I		
AP 7.7	Produce a list of exceptions for:			
AP 7.7.1	cheque cleared, never issued	I		
AP 7.7.2	cheque cleared, listed as voided	I		
AP 7.7.3	cheque cleared under amount issued	I		
AP 7.7.4	cheque cleared over amount issued	I		
AP 7.7.5	cheque paid over a stop payment	I		
AP 7.7.6	cheque paid, stale-dated	I		
AP 7.8	Provide on-line inquiry capabilities to cheque information by entity and cheque number, including status of cheque and date of activity	I		
AP 7.9	Provide the ability to recreate a list of outstanding cheques as of a prior date	I		
AP 7.10	Provide a daily listing of issued cheques by entity and cheque number	I		
AP 7.11	Provide ability to automatically reconcile and transfer outstanding cheques as stale dated based on criteria such as cheque date	N		
AP 7.12	Maintain a history file of cleared or redeemed cheques by cheque type and by entity	I		
AP 7.13	Provide a daily batch control report summarizing accepted, rejected, and prior activity cheque reconciliation transactions from all sources of input with error messages	I		
AP 7.14	Provide for an error suspense report listing all items and actions taken against any of the items with redeemed cheques in suspense remaining until reconciled or adjusted	N		
AP 7.15	Provide for a daily cheque reconciliation activity report showing all the daily on-line update activity in the system	N		
Inquiry and Reporting				
AP 8.1	Provide on-line inquiry using the following as a key:			
AP 8.1.1	Vendor name	V		

D	ACCOUNTS PAYABLE	Priority	Solution	Comments
AP 8.1.2	Vendor alpha search names	V		
AP 8.1.3	Vendor number	V		
AP 8.2	Report all unmatched documents such as invoices with no receiving report or vice versa	I		
AP 8.3	Report rejected transactions received from external interfacing system	I		
AP 8.4	Report unpaid vouchers in the following sequences:			
AP 8.4.1	By department/organizational unit	N		
AP 8.4.2	By payment date (daily cash forecast)	I		
AP 8.4.3	By vendor number	I		
AP 8.4.4	By vendor name	I		
AP 8.5	Report all unpaid vouchers by aging categories	I		
AP 8.6	Report all disbursements by department/entity and expenditure classification	N		
AP 8.7	List all outstanding pre-encumbrances and encumbrances using various classifications, including by account code structure and in total	I		
AP 8.8	Summarize all expenditures for a specified time period, indicating the original appropriation balance, original allotment balance if applicable, total expenditures, outstanding encumbrances, pre-encumbrances, and remaining appropriation and allotment balances available for expenditure	I		
AP 8.9	Report all expenditures for a specified time period by the following classification methods:			
AP 8.9.1	Function (major service or responsibility)	N		
AP 8.9.2	Activity (specific purpose or objective)	N		
AP 8.10	Report expenditures by multiple periods, including monthly, quarterly and annual	I		
AP 8.11	Provide inquiry and reporting of encumbrances indicating the following:			
AP 8.11.1	Original encumbrance amount	I		
AP 8.11.2	Source document number	I		
AP 8.11.3	All transaction amounts and dates affecting the encumbrance (e.g., modifications to the original amount, liquidations, retainages)	I		
AP 8.11.4	Current encumbrance balance	I		
AP 8.12	Provide an inquiry of vendor payment history, including all vendor transactions on a departmental, entity, or consolidated entity basis	I		
AP 8.13	Provide inquiry of open/unpaid invoices by vendor	I		
AP 8.14	Maintain a cheque history file, indicating basic information about cheques (ie, date, payee, amount, etc.) and their disposition (ie., paid, outstanding, stale and written off, etc.) for a user specified period	I		
AP 8.15	Provide system wide reconciliation report subsidiary ledger to control account general ledger	N		
AP 8.16	Cross cheque with P-Card transactions by vendor/invoice#	N		

D	ACCOUNTS PAYABLE	Priority	Solution	Comments
AP 8.17	Provide drill down capability from summarized source journals to detail transactions from subsidiary ledgers	N		
AP 8.18	Provide ability to see payments made to vendor for specified time period cross referencing PO or voucher or vendor contract	I		
AP 8.19	Provide employee reimbursements report	N		
AP 8.20	Create ad hoc reports	I		
AP 8.21	Provide a Report of vendors who were paid over a user defined dollar figure/period	N		

Functional Requirements Workbook

Priority Requirements

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E PURCHASING/PROCUREMENT

		Priority	Solution	Comments
General Requirements				
PO 1.2	Automatically assign a unique source document number, in sequential order, within each document type for the following documents, including, but not limited to:			
PO 1.2.1	Requisitions	V		
PO 1.2.2	Blanket Purchase Order	V		
PO 1.2.3	Purchase orders not initiated by a requisition	V		
PO 1.2.4	Release purchase orders	V		
PO 1.2.5	Purchase orders initiated by a requisition	V		
PO 1.2.6	Bid requests for invitations to bid, request for quotes and request for proposal	V		
PO 1.3	Record text and descriptions about the following:			
PO 1.3.1	Items being purchased	I		
PO 1.3.2	Standard clauses and text	I		
PO 1.3.3	Contract terms	I		
PO 1.3.4	Vendors/suppliers	I		
PO 1.3.5	Purchase orders	I		
PO 1.3.6	Requisitions	I		
PO 1.4	Allow automatic use of standard specifications to speed creation of:			
PO 1.5.1	Requisitions	I		
PO 1.5.2	Purchase orders	I		
PO 1.4.3	Blanket purchase orders	I		
PO 1.4.4	Invitations to Bid	I		
PO 1.5	Support the printing of drafts, final/original, additional copies and change orders for requisitions, purchase orders, blanket purchase orders, and all other system forms	I		
PO 1.6	Provide the flexibility to print system forms remotely in the various departments and centrally in Purchasing	I		
PO 1.7	Provide the ability to match commodity codes to vendors	I		
PO 1.8	Provide the ability to print mailing labels selectively	N		

E	PURCHASING/PROCUREMENT	Priority	Solution	Comments
PO 1.9	Flexibility in calculating taxes, by line item and percentages, to maintain pace with evolving government policies	I		
PO 1.10	Ability to support electronic and digital signatures	I		
PO 1.11	Support use of various templates to ensure that language regarding Bonds, Insurance and WCB are noted on purchase requisitions/p.o..	I		
PO 1.12	Support EDI, fax, or other electronic transmittal capabilities for purchase orders and other procurement functions	I		
Requisitions				
PO 2.1	To support recording vendor quotes for requisition processing, retrieve the following information from the vendor/supplier and bid/quote files:			
PO 2.1.1	Vendor numbers for item being requisitioned	I		
PO 2.1.2	Vendors' names and addresses	I		
PO 2.1.3	Items supplied information	I		
PO 2.2	Provide a mechanism to cross-reference requisitions to the corresponding bids, purchase orders, and vice versa	N		
PO 2.3	Allow grouping of department requisitions based on user specified criteria, including the following:			
PO 2.3.1	Department	N		
PO 2.3.2	Entity	I		
PO 2.3.3	Assigned buyer	N		
PO 2.4	Provide mechanism for approved requisition to be electronically routed to an "in box" in a specified department. Allow access by the department to the "in box" and assignment of individual requisitions to specific buyers for processing	N		
PO 2.5	Allow printing of a listing of all requisitions contained in an electronic "in box"	N		
PO 2.6	Provide the capability for at least five levels of approval; from initiation of the requisition through award of the purchase order based on:			
PO 2.6.1	Initiating department/entity/management level	I		
PO 2.6.2	Document/document type	I		
PO 2.6.3	Various Dollar amounts	I		
PO 2.7	Provide edit checks, including, but not limited to, the following:			
PO 2.7.1	Valid account code structure	I		
PO 2.7.2	Valid buyer code	I		
PO 2.7.3	Valid commodity code	I		
PO 2.7.4	Proper level of approval has been indicated	I		
PO 2.7.5	Valid budget authority	I		
PO 2.8	Record pre-encumbrance amounts against the budget amount available for spending	I		
PO 2.9	Allow partial or full liquidation of pre-encumbrance amounts with proper authority	I		
PO 2.10	Allow to limit user ability to enter requisitions for a specific organizational unit	I		

E	PURCHASING/PROCUREMENT	Priority	Solution	Comments
PO 2.11	Provide the ability to indicate multiple receiving (ship-to) addresses	N		
PO 2.12	Provide the ability to indicate a delivery schedule including the date the deliveries are to be made and the quantity to be delivered to each location/address for the items requested	I		
PO 2.13	Provide an on-line view of a requisition that mirrors the image of the complete printed page	N		
Bid Requests/Quotes				
PO 3.1	Provide on-line inquiry or reporting of potential bidders based on various user-specified criteria, such as:			
PO 3.1.1	Vendor's status (active, suspended, etc.)	N		
PO 3.1.2	Commodities provided	N		
PO 3.1.3	Be able to distinguish between a bidder and an active vendor	N		
PO 3.2	Provide the ability to select multiple bidders from the vendor file for a given commodity	N		
PO 3.3	Maintain bidder information and produce various types of bidder lists, using various user-specified criteria	N		
PO 3.4	Provide the ability to print a vendor's name and address from the vendor file on all bid request forms	N		
PO 3.5	Provide the capability to print mailing labels for vendors on the bidders' lists	N		
PO 3.6	Provide the ability to customize the format of and print on various printers:			
PO 3.6.1	Invitations to Bid	N		
PO 3.6.2	Requests for Quotes	N		
PO 3.6.3	Requests for Proposals	N		
PO 3.7	Provide on-line and hard copy reporting of standard bid request instructions and details specific to that bid	I		
PO 3.8	Maintain historical data for the following:			
PO 3.8.1	Purchase Order	I		
PO 3.8.2	Invitation to Bids	I		
PO 3.8.3	Requests for Quotes	N		
PO 3.8.4	Requests for Proposals	N		
PO 3.8.5	Vendor bid responses	N		
PO 3.9	Provide ability to generate Supplier Notification Form	N		
PO 3.10	Provide the ability to generate hard copy of bid tabulation/evaluation	N		
Purchase Orders and Contracts				
PO 4.1	Support for issuance of the following types of purchase order:			
PO 4.1.1	Purchase order preceded by an electronic requisition for either goods or services	I		
PO 4.1.2	Purchase order not preceded by a electronic requisition for either goods or services	I		
PO 4.1.3	Release order placed against a blanket purchase order	I		
PO 4.1.4	Purchase order for a specific dollar amount and a specific supplier for certain goods and services on an as required basis	I		

E	PURCHASING/PROCUREMENT	Priority	Solution	Comments
PO 4.1.5	Blanket purchase order for a specific supplier for certain goods and services which may or may not specify a unit cost and maximum dollar spending limit	I		
PO 4.2	Record and prepare the following data on-line:			
PO 4.2.1	Initial purchase order execution/award	N		
PO 4.2.2	Renewals/extensions with complete record of all changes	N		
PO 4.2.3	Amendments/change orders with complete record of all changes	I		
PO 4.2.4	Cancellations/Deletions	I		
PO 4.3	Provide the ability to update the requisition/purchase order while in draft form prior to final approval without having to process a change order	I		
PO 4.4	Provide the ability to book a pre-encumbrance while waiting on the final agreement encumbering funds on a change order	N		
PO 4.5	Allow recording of purchase order changes on-line, provide an audit trail for all changes made to the purchase order	I		
PO 4.6	Provide an ability to assign project accounting data per line item	I		
PO 4.7	Maintain purchase order information through multiple fiscal years and maintain the same purchase order number	N		
PO 4.8	Provide the ability to indicate multiple receiving (ship-to) locations	N		
PO 4.9	Provide the ability to indicate a delivery schedule including date, item quantity, and location/address for the items ordered	N		
PO 4.10	Provide an on-line view of the purchase order that mirrors the printed image	N		
PO 4.11	Provide the ability to show the reporting of purchase order payment history that includes the cheque numbers	I		
PO 4.12	Provide the ability to process purchase orders in December that encumber funds in January of the new fiscal year	I		
PO 4.13	Provide alert/warning before contract expiration using user-defined criteria	N		
PO 4.14	Provide easy ability to view balance remaining on a PO	I		
Receiving				
Inquiry and Reporting				
PO 6.1	Provide on-line inquiry of commodities supplied by each vendor and vice versa	N		
PO 6.2	Report outstanding purchase requisitions by department or buyer, indicating the following:			
PO 6.2.1	Requisition number	I		
PO 6.2.2	Requested delivery date	I		
PO 6.2.3	Requisition amount	I		
PO 6.2.4	Buyer name	I		
PO 6.2.5	Status	I		
PO 6.2.6	Date received in Purchasing	I		
PO 6.3	Allow on-line inquiry of the following:			
PO 6.3.1	Requisitions, including status	I		
PO 6.3.2	Purchase orders, all types	I		

E	PURCHASING/PROCUREMENT	Priority	Solution	Comments
PO 6.3.3	Invitation to Bids	I		
PO 6.3.4	Requests for Quotes	N		
PO 6.3.5	Requests for Proposals	N		
PO 6.4	Support inquiry into encumbrances (summary and detail) by department	I		
PO 6.5	Provide on-line inquiry of purchase orders by department number, purchase order number, bid number, requisition number, and vendor name	I		
PO 6.6	Provide a report that lists remaining amounts and vouchers paid against purchase order.	I		

Functional Requirements Workbook

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F	INVENTORY MANAGEMENT	Priority	Solution	Comments
General Requirements				
Inventory Data				
IM 2.1	Track following Inventory Items info:			
IM 2.1.1	Item Number	C		
IM 2.1.2	Item Status	V		
IM 2.1.3	Item Description (short and long)	C		
IM 2.1.4	Different Units of measure for purchasing and Issuing	V		
IM 2.1.5	Item Location	V		
IM 2.1.6	Item Shelf Life or Expiration Date	I		
IM 2.1.7	Item Unit Cost	C		
IM 2.1.8	Other Item Unit Costs (shipping, delivery, etc.)	V		
IM 2.1.9	True Item Unit Cost	V		
IM 2.1.10	Bulk Cost	V		
IM 2.1.11	Average Price	V		
IM 2.1.12	Vendor Number	I		
IM 2.1.13	Primary Vendors	I		
IM 2.1.14	Min-Max Points	V		
IM 2.1.15	Quantity on hand	C		
IM 2.1.16	Quantity on order	C		
IM 2.1.17	Quantity received on orders	C		
IM 2.1.18	Quantity on back-order	C		
IM 2.1.19	Ordered year-to-date	V		
IM 2.1.20	Received year-to-date	V		
IM 2.1.21	Issued current period	V		
IM 2.1.22	Issued year-to-date	V		
IM 2.1.23	Commodity Code	V		
IM 2.1.24	Lead Time/Lead Lag	I		
IM 2.1.25	Turnover Rate	I		
IM 2.1.26	Warranty	I		
IM 2.1.27	Internal Ownership	I		
IM 2.1.28	Project Stock	V		

F	INVENTORY MANAGEMENT	Priority	Solution	Comments
IM 2.1.29	Item nature - new, used, refurbished	V		
IM 2.1.30	Other user-defined fields	I		
IM 2.2	Allow unlimited number of Inventory Items	V		
IM 2.3	Cross-reference manufacturer's part number(s) with warehouse part number	I		
IM 2.4	Support Inventory Items with zero dollar value and/or zero quantity	I		
IM 2.5	Provide ability to display images for all Inventory items	N		
IM 2.6	Support referencing on-line vendor catalogues	N		
IM 2.7	Maintain Inventory Item data specific for the following transactions:			
IM 2.7.1	Purchases	V		
IM 2.7.2	Returns to suppliers	V		
IM 2.7.3	Returns to stock	V		
IM 2.7.4	Adjustments (e.g., credits, etc.)	V		
IM 2.7.5	Transfers	V		
IM 2.7.6	Receipts	V		
IM 2.7.7	Requisitions	V		
IM 2.7.8	Backorders	V		
IM 2.7.9	Defective or damaged parts returned to vendors	V		
IM 2.7.10	Issuance of Inventory	V		
IM 2.7.11	Recalls	V		
IM 2.7.12	Surplus/junk/spoiled items	V		
IM 2.8	Support multiple inventory control accounts	I		
IM 2.9	Support multi-level location structure with the following info:			
IM 2.9.1	Building, Room and Desk	I		
IM 2.9.2	Warehouse	I		
IM 2.9.3	Storage Area	I		
IM 2.9.4	Aisle	I		
IM 2.9.5	Bin	I		
IM 2.9.6	Shelf	I		
IM 2.9.7	Rack	I		
IM 2.9.8	Cart	I		
IM 2.9.9	Required environmental conditioned for the specific locations	I		
IM 2.9.10	Other user-defined fields	I		
IM 2.10	Provide the ability to default each user sign-on to a primary warehouse and printer for warehouse documents	I		
IM 2.11	Provide the ability for users to override their default warehouse for exception transactions	I		
IM 2.12	Support allocation of purchases and stock to various departments, warehouses, sections of the warehouse, etc.	V		
IM 2.13	Support primary and multiple secondary locations for Inventory Items	I		
IM 2.14	Produce and track stock tags with the following info:			
IM 2.14.1	Stock location	I		
IM 2.14.2	Item number	I		
IM 2.14.3	Unit of measure	I		

F	INVENTORY MANAGEMENT	Priority	Solution	Comments
IM 2.14.4	Cost	I		
IM 2.14.5	Commodity Code	N		
IM 2.14.6	Issuing unit by location	N		
IM 2.14.7	Manufacturer name	N		
IM 2.14.8	Manufacturer's part number	N		
IM 2.14.9	Part Number	N		
IM 2.14.10	Reference Field	N		
IM 2.14.11	Other user-defined fields	N		
Transaction Processing				
IM 3.1	Support electronic approval process for the following transactions:			
IM 3.1.1	Receipts	I		
IM 3.1.2	Returns	I		
IM 3.1.3	Issues	I		
IM 3.1.4	Requisitions	I		
IM 3.2	Provide stock on hand for each location	I		
IM 3.3	Provide stock on hand for multiple locations	I		
IM 3.4	Issue alerts to the defined user when stock is zero	I		
IM 3.5	Track item usage and provide automatic notification to defined users of all items under the minimum on hand quantity or at the re-order point	V		
IM 3.6	Allow user-defined re-order points and quantities	V		
IM 3.7	Permit automatic adjustment of re-order points based on usage history, forecasted demand and other user-defined criteria	I		
IM 3.8	Support automatic re-order process for all, or selected stock items with electronic request and approval process	V		
IM 3.9	Automatically adjust item cost in the inventory base on transactions performed in the accounts payable	V		
IM 3.10	Allow users to specify a mark-up or overhead cost for each Inventory Item	I		
IM 3.11	Capture quantities in metric or imperial units and automatically convert to established product standard	N		
IM 3.12	Convert between different units of measure automatically (e.g. purchase vs. issue unit)	N		
IM 3.13	Transfer items between warehouses and sites	I		
IM 3.14	Schedule pick-up and transfer of inventory utilizing the most efficient process	I		
IM 3.15	Automatically determine most efficient pick location	N		
IM 3.16	Provide charge out stock withdrawn from inventory to the requesting department	I		
IM 3.17	Provide users with ability to view all system documents related to an inventory charge-out requests	I		
IM 3.18	Provide requisition self service functionality	I		
IM 3.19	Assign stock requisition numbers:			
IM 3.19.1	Automatically	I		
IM 3.19.2	Manually	O		

F	INVENTORY MANAGEMENT	Priority	Solution	Comments
IM 3.20	Perform following transactions on stock requisitions:			
IM 3.20.1	Edit/Modify	V		
IM 3.20.2	Reverse	V		
IM 3.20.3	Cancel	V		
IM 3.20.4	Reject	V		
IM 3.21	Generate pick list at pre-scheduled times	I		
IM 3.22	Automatically update inventory on-order information during requisition creation	I		
IM 3.23	Reserve stock items for specific project or work order based upon requisition utilizing user-defined time frames	V		
IM 3.24	Support assigning of the inventory to:			
IM 3.24.1	Employees	N		
IM 3.24.2	Crew	N		
IM 3.24.3	Work Unit	N		
IM 3.24.4	Vehicle	N		
IM 3.24.5	Other user-defined breakdown	N		
IM 3.25	Support placing a cap on the quantity of an item that can be issued to a requestor during a specified time period with override approval	N		
IM 3.26	Support placing a cap on the dollar amount of an item that can be issued to a requestor during a specified time period with override approval	N		
Physical Inventory				
Inquiry and Reporting				
IM 5.1	Supports key word/phrase search capability	N		
IM 5.2	Inventory Status Report	I		
IM 5.3	Departmental Charge Summary Report	I		
IM 5.4	Report on quantities consumed in a rolling 12 month period by part number	N		
IM 5.5	Min-max reporting based on historical usage	N		
IM 5.6	Inventory Count Report	I		
IM 5.7	Physical inventory discrepancy report	I		
IM 5.8	Reports on obsolescence and overstock	I		
IM 5.9	Inventory Pick Report by work order	I		
IM 5.10	Economic Order Quantity Report	I		
IM 5.11	Suggested Order Report	I		
IM 5.12	Reorder Point Report	I		
IM 5.13	Inventory Valuation Report	I		
IM 5.14	Item Order Status	I		
IM 5.15	List of Expired Items	N		
IM 5.16	Where Used Report	N		

Priority Requirements

C	Critical, proposals may be disqualified if several of these requirements not met
V	Required Very Important, System Severely limited or compromised
I	Important, preferred solution should have these
N	Nice to Have, moderately important
O	Optional. Least Important, but system would benefit

Solution Classification

Core	Functionality resides in basic FIS
Client Configure	Functionality is available to clients to configure
Optional	Functionality not available in basic FIS but would be available as an upgrade or add-on
Pending	Planned functionality not yet available but will be in near future - indicate if it will be Core or Optional
N/A	Not presently available and not planned for near future

G FIXED ASSETS

		Priority	Solution	Comments
General Requirements				
FA 1.1	Maintain an audit trail of all fixed assets transactions	C		
FA 1.2	Provide the ability for all transactions to be captured through stationary/hand-held bar code readers or portable memory barcode data terminals and uploaded to the system.	N		
FA 1.3	Maintain a detailed transaction ledger of all transactions	C		
Fixed Assets Data				
FA 2.1	Track unlimited number of:			
FA 2.1.2	Capitalized items	V		
FA 2.1.3	Non-capitalized items	I		
FA 2.2	Following Fixed Asset item data should be available:			
FA 2.2.1	Asset number	V		
FA 2.2.2	Account code	V		
FA 2.2.3	Serial number	V		
FA 2.2.4	Account number	V		
FA 2.2.5	Commodity code	I		
FA 2.2.6	Description	V		
FA 2.2.7	Asset Category	V		
FA 2.2.8	Asset type	I		
FA 2.2.9	Asset sub-type	I		
FA 2.2.10	Location	N		
FA 2.2.11	Bar code number	N		
FA 2.2.12	Project number/identifier	I		
FA 2.2.13	Parent-child relationship	I		
FA 2.2.14	Responsible (e.g., department, employee, etc.)	N		
FA 2.2.15	Acquisition date	I		
FA 2.2.16	Vendor	N		
FA 2.2.17	Purchase cost	V		
FA 2.2.18	Assessed value of land	N		
FA 2.2.19	Acquisition method (ie, contributed capital, purchased, etc.)	N		
FA 2.2.20	In Service Date	V		
FA 2.2.21	Asset Status (ie, sold, re-placed, disposed, etc.)	V		
FA 2.2.22	Useful life	V		

G	FIXED ASSETS	Priority	Solution	Comments
FA 2.2.23	Remaining life	V		
FA 2.2.24	Make and/or model, year	I		
FA 2.2.25	Maintenance schedule	N		
FA 2.2.26	Actual dates of maintenance	N		
FA 2.2.27	Maintenance provider	N		
FA 2.2.28	Warranty terms and Expiration date	N		
FA 2.2.29	Software license information	N		
FA 2.2.30	Support Agreement	N		
FA 2.2.31	Software version	N		
FA 2.2.32	Complete asset valuation data	N		
FA 2.2.33	Trailing costs	N		
FA 2.2.34	User-defined fields	N		
FA 2.3	Specify location of an asset using:			
FA 2.3.1	Relational location coordinates	N		
FA 2.3.2	Global Positioning System (GPS) identifier	N		
FA 2.3.3	Building, floor, room number	N		
FA 2.3.4	Address	N		
FA 2.3.5	Legal description (including parcel, block, etc.)	N		
FA 2.3.6	Auto-CAD information	N		
FA 2.3.7	Department responsible for the asset	N		
FA 2.3.8	Individual with possession of the asset	N		
FA 2.4	Record following insurance information:			
FA 2.4.1	Insurance company name	N		
FA 2.4.2	Insurance company address	N		
FA 2.4.3	Insurable value	N		
FA 2.4.4	Primary policy holder	N		
FA 2.4.5	Policy number	N		
FA 2.4.6	Policy period	N		
FA 2.4.7	Renewal date	N		
FA 2.4.8	Coverage type	N		
FA 2.4.9	Liability limits	N		
FA 2.4.10	Premium	N		
FA 2.4.11	Construction type	N		
FA 2.4.12	Fire and construction codes	N		
FA 2.4.13	Number of stories	N		
FA 2.4.14	Square meters	N		
FA 2.4.15	Assessed value and last assessment date	N		
FA 2.4.16	Contents	N		
FA 2.4.17	Owned/leased/rented/managed	N		
FA 2.4.18	User-defined fields and criteria	N		
FA 2.5	Maintain following information on asset disposals, retirement, loss, theft and trade-ins:			
FA 2.5.1	Asset number	I		
FA 2.5.2	Reporting department and Individual	N		
FA 2.5.3	Date of occurrence	I		

G FIXED ASSETS		Priority	Solution	Comments
FA 2.5.4	Description of circumstances	N		
FA 2.5.5	Steps taken to locate the item	N		
FA 2.5.6	Disposal date	I		
FA 2.5.7	Disposal amount	I		
FA 2.5.8	Disposal method	I		
FA 2.5.9	Original cost	I		
FA 2.5.10	Accumulated depreciation	I		
FA 2.5.11	Book value	I		
FA 2.5.12	User-defined fields	N		
Transaction Processing				
FA 3.1	Support copying existing asset record to create a similar asset record	N		
FA 3.2	Accommodate splitting a single asset between multiple assets	N		
FA 3.3	Support electronic approval process for the following transactions:			
FA 3.3.1	Transfers	I		
FA 3.3.2	Disposals	I		
FA 3.3.3	Asset item data corrections after creation (e.g., adjustments of the original asset cost, useful life, etc.)	I		
FA 3.4	Write-off assets upon disposals	I		
FA 3.5	Write-off assets after a defined period	I		
FA 3.6	Support purging and archiving of the inactive fixed assets records based on user defined criteria	N		
FA 3.7	Allow for a selected group of assets to be set to a particular depreciation method, without individually assigning it to each asset	I		
FA 3.8	Provide electronic alert to appropriate users when trailing cost period - a specified period (usually 1 year) - is passed from the in-service date	N		
Physical Counts/Adjustments				
Inquiry and Reporting				
FA 5.1	Provide following Reports:			
FA 5.1.1	Detailed inventory of all Fixed Assets	V		
FA 5.1.2	Disposals and Transfers	V		
FA 5.1.3	Total acquisitions	V		
FA 5.1.4	Assets assigned to individuals	N		
FA 5.1.5	Detailed Insurance Information	N		
FA 5.1.6	Changes in Fixed Assets	V		
FA 5.1.7	Write-offs	V		
FA 5.1.8	Fully depreciated items	I		
FA 5.1.9	Gains/losses for disposed assets	V		
FA 5.2	Generate reports based on "activity" (e.g., beginning balance, year's depreciation, ending current value)	V		
FA 5.3	Ability to export to Excel any reports or queries	V		

#REF!

Functional Requirem

Priority Requirements

C	Critical, proposals may be disqualified if several of these requirements not met
V	Required Very Important, System Severely limited or compromised
I	Important, preferred solution should have these
N	Nice to Have, moderately important
O	Optional. Least Important, but system would benefit

H PROJECT COSTING

General Requirements	
PC 1.1	System will support multiple-year projects
PC 1.2	System will provide a field for a unique identification number for each project in effect throughout its lifecycle
PC 1.3	System will support unlimited hierarchy of projects linked into programs and portfolios (parent-child relations for projects and sub-projects)
PC 1.4	System will support grouping or splitting projects
PC 1.5	System will allow master project data to be copied for set-up of new projects in system
PC 1.6	System maintains historical data for all projects throughout the life of the project and for a user-specified period after project close. Global definition of this record retention date/period must exist. Deletion of a project must be confirmed by prompting the user
PC 1.7	System will use free form text for project descriptions
PC 1.8	System allows embedded attachment of supporting documents
Project Accounting	
PC 2.1	System maintains the following financial and related project information:
PC 2.1.1	Budgets
PC 2.1.2	Pre encumbrances
PC 2.1.3	Encumbrances
PC 2.1.4	Expenditures
PC 2.1.5	Receivables
PC 2.1.6	Revenues
PC 2.1.7	Penalties
PC 2.1.8	Retentions/Hold-backs
PC 2.1.9	Scope changes
PC 2.1.10	Amendments/Change orders
PC 2.1.11	Ability to save multiple iterations and types of budget

H PROJECT COSTING

PC 2.2	System accommodates project budgets to be controlled by the following elements:
PC 2.2.1	Fiscal year
PC 2.2.2	Funding Source
PC 2.2.3	Department
PC 2.2.4	Function
PC 2.2.5	Project
PC 2.2.6	Project manager
PC 2.2.7	Program
PC 2.2.8	Activity
PC 2.2.9	Task
PC 2.2.10	Phase
PC 2.3	System will automatically transfer from AP all project-related expenses.
PC 2.4	System will automatically record POs for projects as commitments
PC 2.5	System will allow direct entry of project commitments
PC 2.6	System will allow for equipment costs for assets under construction to be recorded in system prior to capitalization
PC 2.7	System will provide ability for projects to accumulate employee costs based on actual costs (salary and user defined benefit & employment costs)
PC 2.8	System will provide ability for projects to accumulate employee costs based on actual costs plus uplift
PC 2.9	System will provide ability for projects to accumulate employee costs based on role/employee grade rates
PC 2.10	System will provide ability for projects to accumulate employee costs based on standard costs
PC 2.11	System will track budget-vs.-actual and percent of completion (summary or line item levels)
PC 2.12	System will allow the user to specify and control the project closing process with appropriate security
PC 2.13	System will allow simultaneous closing of multiple projects at the user's options
PC 2.14	System will allow for multiple user-defined closure dates
PC 2.15	System will close projects partially or completely
PC 2.16	System will allow users to re-open a closed project subject to workflow and security constraints
PC 2.17	System will provide an automated procedure to purge and archive data for closed projects
PC 2.18	System will identify inactive projects for possible close. The definition of 'inactive' should be user-defined by setting business rules for project data fields
PC 2.18	System will update the following types of accounts during a close:
PC 2.18.1	Capitalization
PC 2.18.2	Expenses

H PROJECT COSTING

PC 2.18.3	Assets
PC 2.19	System will allow for projects may be flagged as billable.
PC 2.20	System will allow billing of fixed amount (contract value).
PC 2.21	System will allow billing of actual costs incurred.
PC 2.22	System will allow billing of actual costs incurred with percentage uplift.
PC 2.23	System will allow milestone-based billing.
PC 2.24	System will allow stage payment billing.
PC 2.25	System will allow recurring billing amounts with percentage increments.
PC 2.26	System will allow percentage of complete billing.
PC 2.27	System will allow user-specified billing schedule.
PC 2.28	System will allow time and rate-based billing (for example, hours worked).
PC 2.29	System will allow user-defined billing methods.
PC 2.30	System will allow for invoices to be previewed online before transmission.
PC 2.31	System will allow for invoices to be saved in a pdf format.
PC 2.32	System will have revenue recognition capability at time of billing and/or at a user defined stage.
PC 2.33	System will be capable to ensure that project billings do not exceed the reimbursable budget with an override capability based on security.
Inquiry and Reporting	
PC 3.1	System will provide the ability to "drill down" from summary information to detail transactions.
PC 3.2	System will provide the ability to "drill back" from source transactions.
PC 3.3	System will accommodate ad hoc querying & reporting.
PC 3.4	System will generate reports from specific dates or ranges of:
PC 3.4.1	Project number or name
PC 3.4.2	Type (for example, capital, operating or other user-defined type)
PC 3.4.3	Departments and organization/division
PC 3.4.4	Year or other user-defined date range
PC 3.4.5	Funding source/type
PC 3.4.6	Location
PC 3.4.7	Project Manager
PC 3.4.8	Work order number
PC 3.4.9	Other user-defined
PC 3.5	System will produce variance reports according to the account ranges specified above.
PC 3.6	System will allow user to modify the level of detail for all reports.
PC 3.7	System will provide an online, real-time inquiry screen that displays the following:
PC 3.7.1	Project budget

H PROJECT COSTING

PC 3.7.2	Pre encumbrances
PC 3.7.3	Encumbrances
PC 3.7.4	Expenditures
PC 3.7.5	Retention
PC 3.7.6	Revenues
PC 3.7.7	Vendor
PC 3.7.8	Customers
PC 3.7.9	Available budget
Project Management	
PC 4.1	System will support integration with Microsoft Project.
PC 4.2	System will permit limiting view of project information for external users (e.g. contractors).
PC 4.3	System should have ability to define roles, their access/authority levels associated with a project (for example, surveyor and consultant), and system as a whole.
PC 4.4	System should allow for billing rates to be held by role, employee grade and employee.
PC 4.5	System should have ability to hold standard rates by role, employee grade and employee.
PC 4.6	System will provide ability to record billable and no billable time.
PC 4.7	System provide ability to record staff vacation time.
PC 4.8	System will provide ability to document Change Request in the system using predefined template.
PC 4.9	System will provide ability to view and compare project budgets, forecasts, actual, commitment and earned value amounts.
PC 4.10	System will provide ability to do performance exception reporting using visual indicators (in dashboard and elsewhere).
PC 4.11	System must support various project performance metrics (e.g. earned value, CPI, SPI).
PC 4.12	System will allow data be viewed in datasheet view (similar to excel) to process multiple sets of data in a single window.
PC 4.13	System will allow to associate a contract detail to one or many projects
PC 4.14	System will allow record and maintain various document/report/file details associated to a project

ents Workbook

Solution Classification

Core	Functionality resides in basic FIS
Client Configure	Functionality is available to clients to configure
Optional	Functionality not available in basic FIS but would be available as an upgrade or add-on
Pending	Planned functionality not yet available but will be in near future - indicate if it will be Core or Optional
N/A	Not presently available and not planned for near future

Priority	Solution	Comments
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Priority	Solution	Comments
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Request for Proposals

For

Provision of Financial Information System for Brantford Power Inc.

Request for Proposals No.: **15-17**

Issued: **April 16, 2015**

Submission Deadline**: May 14, 2015**

TABLE OF CONTENTS

PART 1 – INVITATION AND SUBMISSION INSTRUCTIONS

1.1 Invitation to Proponents

This Request for Proposals (the "RFP") is an invitation by Brantford Power Inc. ("BPI") to prospective proponents to submit proposals for the provision of Financial Information System for BPI**,** as further described in the RFP Particulars (Appendix D) (the "Deliverables").

BPI's preference is for a hosted FIS solution. The data centre must reside in Canada. Data cannot cross Canadian borders for any reason.

BPI considers the following list of items as required to successfully satisfy the intent of this RFP:

- Project management, system design, commissioning, and training;
- Creation and implementation of all required interfaces including technical expertise required to establish communications between the FIS and BPI's back office systems;
- System security (i.e., detailed security parameters to protect all information collected and stored);
- Service levels and value added services;
- Applicable costs, pricing and rates;
- Conversion assistance to convert from the existing FIS solution(s) to the new FIS;
- Detailed reporting functionality;
- Business Intelligence; and
- Ongoing technical support and updates.

This RFP bid solicitation is being issued by the City of Brantford on behalf of Brantford Power Inc. All issues related to this RFP pre-award shall be dealt with by the City, on behalf of Brantford Power Inc. The agreement shall be between Brantford Power Inc. and the selected proponent.

1.2 BPI's Procurement Policy

BPI's procurement processes are governed by the BPI's Purchasing Policy – Policy No.1 (BPI's Policy"). It is the Proponent's responsibility to become familiar with and comply with BPI's Policy, which is available on line at:

http://brantfordpower.com/about-brantford-power-inc/financial-regulatory-affairs/reports/

1.3 RFP Contact

For the purposes of this procurement process, the "RFP Contact" shall be:

Eva Cislo, Buyer
Email: evacislo@brantford.ca

Proponents and their representatives are not permitted to contact any employees, officers, agents, elected or appointed officials or other representatives of the City or BPI, other than the RFP Contact, concerning matters regarding this RFP. Failure to adhere to this rule may result in the disqualification of the proponent and the rejection of the proponent's proposal.

1.4 Type of Contract for Deliverables

The selected proponent will be requested to enter into direct contract negotiations to finalize an agreement with BPI for the provision of the Deliverables. The terms and conditions found in the Form of Agreement (Appendix A) are to form the basis for commencing negotiations between BPI and the selected proponent. It is the BPI's intention to enter into an agreement with only one legal entity.

1.5 RFP Timetable

Issue Date of RFP	**April 16, 2015**
Deadline for Questions	**May 5, 2015**
Deadline for Issuing Addenda	**May 8, 2015**
Submission Deadline	**May 14, 2015 at 3:00:59 p.m.**
Rectification Period	**2 business days**
Anticipated Initial Ranking and Demonstrations	**June 8, 2015**
Commencement of Concurrent Negotiations	**June 22, 2015**
Anticipated Deadline for Submission of Best and Final Offers ("BAFO")	**July 8, 2015**
Anticipated Final Ranking	**July 22, 2015**
Contract Negotiation Period	**30 business days**

The RFP timetable is tentative only, and may be changed by BPI at any time based on BPI's requirements.

1.6 Submission of Proposals

1.6.1 Proposals to be Submitted at the Prescribed Location

Proposals must be submitted at:

Purchasing Division – Finance Department
City of Brantford
1 Market Square, Lower Level, Suite 120
Brantford, Ontario
N3T 6C8

1.6.2 Proposals to be Submitted on Time

Proposals must be submitted at the location set out above on or before the Submission Deadline. Proposals submitted after the Submission Deadline will be rejected.

1.6.3 Proposals to be Submitted in Prescribed Format

Proponents should submit 7 hard copies of their proposal and 1 electronic copy of their proposal in accordance with the instructions below. If there is a conflict or inconsistency between the hard copy and the electronic copy of the proposal, the hard copy of the proposal shall prevail.

The hard copies of the Pricing Form (Appendix C) and any other information in respect of pricing should be separated from the rest of the proposal and enclosed in a separate envelope marked “Pricing Envelope”. Both the separate Pricing Envelope and the rest of the proposal should be packaged together in a sealed package and prominently marked with the RFP title and number (see RFP cover), with the full legal name and return address of the proponent.

The electronic copy of the Pricing Form (Appendix C) and any other information in respect of pricing should be saved in a separate file from the rest of the proposal and clearly identified as the pricing file. Both the separate pricing file and the rest of the proposal should be submitted on a single USB key in the sealed package with the hard copies of the proposal.

1.6.4 Amendment of Proposals

In order to amend a proposal submitted prior to the Submission Deadline the proponent must withdraw the previously submitted proposal in accordance with section 1.6.5, below, and submit a new proposal prior to the Submission Deadline.

1.6.5 Withdrawal of Proposals

At any time throughout the RFP process until the execution of a written agreement for provision of the Deliverables, a proponent may withdraw a submitted proposal. To withdraw a proposal, a notice of withdrawal must be sent to the RFP Contact and must be signed by an authorized representative of the proponent. BPI is under no obligation to return withdrawn proposals.

[End of Part 1]

PART 2 – EVALUATION AND NEGOTIATION

2.1 Stages of Evaluation and Negotiation

BPI will conduct the evaluation of proposals and negotiations in the following five stages:

2.2 Stage I – Mandatory Submission Requirements

Stage I will consist of a review to determine which proposals comply with all of the mandatory submission requirements. If a proposal fails to satisfy all of the mandatory submission requirements, BPI will issue the proponent a rectification notice identifying the deficiencies and providing the proponent an opportunity to rectify the deficiencies. If the proponent fails to satisfy the mandatory submission requirements within the Rectification Period, its proposal will be excluded from further consideration. The Rectification Period will begin to run from the date and time that BPI issues a rectification notice to the proponent. The mandatory submission requirements are as follows:

2.2.1 Submission Form (Appendix B)

Each proposal must include a Submission Form (Appendix B) completed and signed by an authorized representative of the proponent.

2.2.2 Pricing Form (Appendix C)

Each proposal must include a Pricing Form (Appendix C), including the Pricing Schedules, completed according to the instructions contained in the form.

2.2.3 Other Mandatory Submission Requirements

Each proposal must include the completed Functional Requirement Workbook completed according to the instructions contained in the workbook.

2.3 Stage II – Evaluation

Stage II will consist of the following three sub-stages:

2.3.1 Mandatory Technical Requirements

BPI will review the proposals to determine whether the mandatory technical requirements as set out in Section C of the RFP Particulars (Appendix D) have been met. Questions or queries on the part of BPI as to whether a proposal has met the mandatory technical requirements will be subject to the verification and clarification process set out in Part 3.

2.3.2 Rated Criteria

BPI will evaluate each qualified proposal on the basis of the rated criteria as set out in Appendix E – Evaluation Criteria and Ranking Method.

2.3.3 Pricing

Submitted pricing will be evaluated in accordance with the final evaluation and ranking method described in Appendix E – Evaluation Criteria and Ranking Method. The evaluation of price will be undertaken after the evaluation of mandatory requirements and rated criteria has been completed.

2.4 Stage III – Demonstrations

At the conclusion of Stage II, up to three (3) of the highest scoring proponents will be asked to provide a product demonstration. The evaluation of the demonstrations will be in accordance with the final evaluation and ranking method described in Appendix E – Evaluation and Criteria and Ranking Method.

2.5 Stage IV – Concurrent Negotiations

2.5.1 Ranking of Proponents

After the completion of Stage III, all scores will be calculated and the proponents will be ranked in accordance with the final evaluation and ranking method set out in Appendix E.

2.5.2 Concurrent Negotiations and BAFO Process

BPI intends to invite the top two ranked proponents to enter into concurrent negotiations. During these concurrent negotiations, BPI will provide each proponent with any additional information and will seek further information and proposal improvements from each proponent. After the expiration of the concurrent negotiation period, each proponent will be invited to revise its initial proposal and submit its BAFO to BPI.

2.5.3 Evaluation of BAFO and Final Ranking of Proponents

Each BAFO will be evaluated against the same criteria set out in Appendix E and proponents will be assigned a final ranking using the same process set out above. The top-ranked proponent based on the evaluation of the BAFOs will receive a written invitation to enter into a final round of negotiations to finalize the agreement with BPI.

2.5.4 Option not to Engage in BAFO

If after the completion of Stage III there is a difference of greater than twenty percent (20%) between the total score of the top-ranked proponent and the total score of the second-ranked proponent, BPI may choose not to engage in the concurrent negotiations and BAFO process and may proceed directly to contract negotiations with the top-ranked proponent.

2.6 Stage V - Contract Negotiations

2.6.1 Contract Negotiation Process

Any negotiations will be subject to the process rules contained in the Terms and Conditions of the RFP Process (Part 3) and will not constitute a legally binding offer to enter into a contract on the part of BPI or the proponent and there will be no legally binding relationship created with any proponent prior to the execution of a written agreement. The terms and conditions found in the Form of Agreement (Appendix A) are to form the basis for commencing negotiations between BPI and the selected proponent. Negotiations may include requests by BPI for supplementary information from the proponent to verify, clarify or supplement the information provided in its proposal or to confirm the conclusions reached in the evaluation, and may include requests by BPI for improved pricing or performance terms from the proponent.

2.6.2 Time Period for Negotiations

BPI intends to conclude negotiations and finalize the agreement with the top-ranked proponent during the Contract Negotiation Period, commencing from the date BPI invites the top-ranked proponent to enter negotiations. A proponent invited to enter into direct contract negotiations should therefore be prepared to provide requested information in a timely fashion and to conduct its negotiations expeditiously.

2.6.3 Failure to Enter into Agreement

If the parties cannot conclude negotiations and finalize the agreement for the Deliverables within the Contract Negotiation Period, BPI may discontinue negotiations with the top-ranked proponent and may invite the next-best-ranked proponent to enter into negotiations. This process shall continue until an agreement is finalized, until there are no more proponents remaining that are eligible for negotiations or until BPI elects to cancel the RFP process.

2.6.4 Notification to Other Proponents

Other proponents that may become eligible for contract negotiations will be so notified at the commencement of the negotiation process with the top-ranked proponent. Once an agreement is finalized and executed by BPI and a proponent, the other proponents will be notified in accordance with the Terms and Conditions of the RFP Process (Part 3).

[End of Part 2]

PART 3 – TERMS AND CONDITIONS OF THE RFP PROCESS

3.1 General Information and Instructions

3.1.1 Proponents to Follow Instructions

Proponents should structure their proposals in accordance with the instructions in this RFP. Where information is requested in this RFP, any response made in a proposal should reference the applicable section numbers of this RFP.

3.1.2 Proposals in English

All proposals are to be in English only.

3.1.3 No Incorporation by Reference

The entire content of the proponent's proposal should be submitted in a fixed form, and the content of websites or other external documents referred to in the proponent's proposal but not attached will not be considered to form part of its proposal.

3.1.4 References and Past Performance

In determining the acceptability of a proponent, BPI may consider information provided by the proponent's references and may also consider the proponent's past performance or conduct on previous contracts with BPI or other institutions. BPI may disqualify a proponent on the basis of information regarding the proponent's past performance or conduct that BPI finds unsatisfactory or unacceptable.

3.1.5 Information in RFP Only an Estimate

BPI and its advisers make no representation, warranty or guarantee as to the accuracy of the information contained in this RFP or issued by way of addenda. Any quantities shown or data contained in this RFP or provided by way of addenda are estimates only and are for the sole purpose of indicating to proponents the general scale and scope of the Deliverables. It is the proponent's responsibility to obtain all the information necessary to prepare a proposal in response to this RFP.

3.1.6 Proponents to Bear Their Own Costs

The proponent shall bear all costs associated with or incurred in the preparation and presentation of its proposal, including, if applicable, costs incurred for interviews or demonstrations.

3.1.7 Proposal to be Retained by BPI

BPI will not return the proposal or any accompanying documentation submitted by a proponent.

3.1.8 Trade Agreements

Proponents should note that procurements falling within the scope of Chapter 5 of the Agreement on Internal Trade are subject to that trade agreement but that the rights and obligations of the parties shall be governed by the specific terms of this RFP.

3.1.9 No Guarantee of Volume of Work or Exclusivity of Contract

BPI makes no guarantee of the value or volume of work to be assigned to the successful proponent. The agreement to be negotiated with the selected proponent will not be an exclusive contract for the provision of the described Deliverables. BPI may contract with others for goods and services the same as or similar to the Deliverables or may obtain such goods and services internally.

3.2 Communication after Issuance of RFP

3.2.1 Proponents to Review RFP

Proponents shall promptly examine all of the documents comprising this RFP, and may direct questions or seek additional information in writing by email to the RFP Contact on or before the Deadline for Questions. All questions or comments submitted by proponents by email will be deemed to be received once the email has entered into the RFP Contact's email inbox. No such communications are to be directed to anyone other than the RFP Contact. BPI is under no obligation to provide additional information, and BPI is not responsible for any information provided by or obtained from any source other than the RFP Contact. It is the responsibility of the proponent to seek clarification from the RFP Contact on any matter it considers to be unclear. BPI is not responsible for any misunderstanding on the part of the proponent concerning this RFP or its process.

3.2.2 All New Information to Proponents by Way of Addenda

This RFP may be amended only by addendum in accordance with this section. If BPI, for any reason, determines that it is necessary to provide additional information relating to this RFP, such information will be communicated to all proponents by addendum. Each addendum forms an integral part of this RFP and may contain important information, including significant changes to this RFP. Proponents are responsible for obtaining all addenda issued by BPI.

3.2.3 Post-Deadline Addenda and Extension of Submission Deadline

If BPI determines that it is necessary to issue an addendum after the Deadline for Issuing Addenda, BPI may extend the Submission Deadline for a reasonable period of time.

3.2.4 Verify, Clarify and Supplement

BPI may request further information from the proponent or third parties in order to verify, clarify or supplement the information provided in the proponent's proposal, including but not limited to clarification with respect to whether a proposal meets the mandatory technical requirements set out in Section C of the RFP Particulars (Appendix D). BPI may revisit and re-evaluate the proponent's response or ranking on the basis of any such information.

3.3 Notification and Debriefing

3.3.1 Notification to Other Proponents

Once the Agreement is executed between BPI and a proponent, the other proponents will be notified by a formal notice.

3.3.2 Debriefing

Proponents may request a debriefing after receipt of a notification of the outcome of the procurement process. All requests must be in writing to the RFP Contact and must be made within sixty (60) calendar days of such notification. The intent of the debriefing information session is to aid the proponent in presenting a better proposal in subsequent procurement opportunities. Any debriefing provided is not for the purpose of providing an opportunity to challenge the procurement process or its outcome.

3.3.3 Procurement Protest Procedure

If a proponent wishes to challenge the RFP process, it must provide written notice to the RFP Contact within sixty (60) calendar days of notification of the outcome of the procurement process, and BPI will respond in accordance with the dispute resolution process set out in BPI's Policy.

3.4 Conflict of Interest and Prohibited Conduct

3.4.1 Conflict of Interest

BPI may disqualify a proponent for any conduct, situation or circumstances, determined by BPI, in its sole and absolute discretion, to constitute a Conflict of Interest. For the purposes of this Section, "Conflict of Interest" has the meaning ascribed to it in the Submission Form (Appendix B).

3.4.2 Disqualification for Prohibited Conduct

BPI may disqualify a proponent, rescind an invitation to negotiate or terminate a contract subsequently entered into if BPI, in its sole and absolute discretion, determines that the proponent has engaged in any conduct prohibited by this RFP.

3.4.3 Prohibited Proponent Communications

A proponent shall not engage in any communications that could constitute a Conflict of Interest and should take note of the Conflict of Interest declaration set out in the Submission Form (Appendix B).

3.4.4 Proponent Not to Communicate with Media

A proponent shall not at any time directly or indirectly communicate with the media in relation to this RFP or any agreement entered into pursuant to this RFP without first obtaining the written permission of the RFP Contact.

3.4.5 No Lobbying

A proponent shall not, in relation to this RFP or the evaluation and selection process, engage directly or indirectly in any form of political or other lobbying whatsoever to influence the selection of the successful proponent(s).

3.4.6 Illegal or Unethical Conduct

Proponents shall not engage in any illegal business practices, including activities such as bid-rigging, price-fixing, bribery, fraud, coercion or collusion. Proponents shall not engage in any unethical conduct, including lobbying, as described above, or other inappropriate communications; offering gifts to any employees, officers, agents, elected or appointed officials or other representatives of BPI; deceitfulness; submitting proposals containing misrepresentations or other misleading or inaccurate information; or any other conduct that compromises or may be seen to compromise the competitive process provided for in this RFP.

3.4.7 Past Performance or Past Conduct

BPI may prohibit a supplier from participating in a procurement process based on past performance or based on inappropriate conduct in a prior procurement process, including but not limited to the following:

(a) illegal or unethical conduct as described above;

(b) the refusal of the supplier to honour its submitted pricing or other commitments; or

(c) any conduct, situation or circumstance determined by BPI, in its sole and absolute discretion, to have constituted an undisclosed Conflict of Interest.

3.4.8 Commercial Relationship and Litigation

BPI may disqualify a proponent if BPI, in its sole and absolute discretion, determines that the commercial relationship between BPI and the proponent has been impaired by the proponent's acts or omissions in connection with a prior or current contract, including where the proponent is or has been threatening or pursuing litigation against BPI in connection with a prior or current contract with BPI.

For the purposes of this section, the acts or omissions of a proponent include the acts or omissions of:

(a) an officer, a director or a majority or controlling shareholder of the proponent;

(b) a partner, associate or affiliate of the proponent; and

(c) an officer, a director or a majority or controlling shareholder of a partner, associate or affiliate of the proponent.

3.5 Confidential Information

3.5.1 Confidential Information of BPI

All information provided by or obtained from BPI in any form in connection with this RFP either before or after the issuance of this RFP

(a) is the sole property of BPI and must be treated as confidential;

(b) is not to be used for any purpose other than replying to this RFP and the performance of any subsequent contract for the Deliverables;

(c) must not be disclosed without prior written authorization from BPI; and

(d) must be returned by the proponent to BPI immediately upon the request of BPI.

3.5.2 Confidential Information of Proponent

A proponent should identify any information in its proposal or any accompanying documentation supplied in confidence for which confidentiality is to be maintained by BPI. The confidentiality of such information will be maintained by BPI, except as otherwise required by law or by order of a court or tribunal. Proponents are advised that their proposals will, as necessary, be disclosed, on a confidential basis, to advisers retained by BPI to advise or assist with the RFP process, including the evaluation of proposals. In addition, proponents are advised that certain contractual information, including pricing information, may be disclosed to the Ontario Energy Board and, accordingly, may become part of the public record. If a proponent has any questions about the collection and use of personal information pursuant to this RFP, questions are to be submitted to the RFP Contact.

3.6 Procurement Process Non-binding

3.6.1 No Contract A and No Claims

This procurement process is not intended to create and shall not create a formal, legally binding bidding process and shall instead be governed by the law applicable to direct commercial negotiations. For greater certainty and without limitation:

(a) this RFP shall not give rise to any Contract A–based tendering law duties or any other legal obligations arising out of any process contract or collateral contract; and

(b) neither the proponent nor BPI shall have the right to make any claims (in contract, tort, or otherwise) against the other with respect to the award of a contract, failure to award a contract or failure to honour a proposal submitted in response to this RFP.

3.6.2 No Contract until Execution of Written Agreement

This RFP process is intended to identify prospective suppliers for the purposes of negotiating potential agreements. No legal relationship or obligation regarding the procurement of any good or service shall be created between the proponent and BPI by this RFP process until the successful negotiation and execution of a written agreement for the acquisition of such goods and/or services.

3.6.3 Non-binding Price Estimates

While the pricing information provided in proposals will be non-binding prior to the execution of a written agreement, such information will be assessed during the evaluation of the proposals and the ranking of the proponents. Any inaccurate, misleading or incomplete information, including withdrawn or altered pricing, could adversely impact any such evaluation or ranking or the decision of BPI to enter into an agreement for the Deliverables.

3.6.4 Cancellation

BPI may cancel or amend the RFP process without liability at any time.

3.7 Governing Law and Interpretation

These Terms and Conditions of the RFP Process (Part 3):

(a) are intended to be interpreted broadly and independently (with no particular provision intended to limit the scope of any other provision);

(b) are non-exhaustive and shall not be construed as intending to limit the pre-existing rights of the parties to engage in pre-contractual discussions in accordance with the common law governing direct commercial negotiations; and

(c) are to be governed by and construed in accordance with the laws of the province of Ontario and the federal laws of Canada applicable therein.

[End of Part 3]

APPENDIX A – FORM OF AGREEMENT

Proposed draft agreement is for consideration by the proponents. Terms and conditions of the final agreement shall be as negotiated and agreed to during the negotiation period.

This Agreement made this day of   , 2015

B E T W E E N:

BRANTFORD POWER INC.
(hereinafter called the "BPI")

OF THE FIRST PART,

-and-

<SUPPLIER LEGAL NAME>
(hereinafter called the "Supplier")

OF THE SECOND PART,

WHEREAS BPI requested proposals from interested proponents (reference RFP 15-17) for the provision of financial information system for Brantford Power Inc., herein after referred to as the “Services”,

AND WHEREAS the Supplier submitted a proposal dated _____________, 2015, (as attached in Schedule B) and in which BPI wishes to accept;

NOW THEREFORE IN CONSIDERATION OF THE MUTUAL COVENANTS HEREIN CONTAINED AND THE PROVISION OF OTHER GOOD AND VALUABLE CONSIDERATION (THE RECEIPT AND ADEQUACY OF WHICH IS ACKNOWLEDGED) THE PARTIES HERETO HAVE AGREED AS FOLLOWS:

1. Services of the Supplier

1.1. The Supplier agrees to perform the services identified in Schedule A (Supplier Proposal, RFP Particulars and any Addenda issued) for BPI.

2. Level of Services

2.1 Unless otherwise expressly specified in this Agreement, the Supplier agrees to supply at its sole cost and expense all labour and material costs, all travel and carriage costs, all insurance costs, all costs of delivery, all costs of installation and set-up, including any pre-delivery inspection charges, and all other overhead and disbursements necessary to perform the Services to be furnished under this Agreement and assume all overhead expenses in connection therewith, to the reasonable satisfaction of BPI.

3. Commencement and Prosecution of Work

3.1 The Supplier shall commence work on this Project when directed by BPI. The Supplier shall proceed with due dispatch to ensure that its obligations are completed as quickly as reasonably possible, but in any event to be completed before ___________, 2015. BPI shall give due consideration to all plans, drawings, reports, tenders, proposals, and other information provided by the Supplier and shall make any decisions which it is required to make in connection therewith within a reasonable time so as not to delay the work of the Supplier.

3.2 BPI shall be entitled to terminate this Agreement at any time without cause, and in the event of such termination, the remuneration payable to the Supplier shall be determined by calculating the proportion of the work completed and applying that proportion to the fees payable hereunder for the Services.

4. Total Contract Price

4.1. BPI shall pay to the Supplier in full payment and compensation for its Services under this Agreement, of which includes all Disbursements, applicable Taxes and excluding H.S.T. (if applicable) for the sum of **<WRITTEN NUMERIC WORDS> DOLLARS and xx/100 ($XX,XXX.XX).**

4.2. Despite section 4.1 above, the parties may agree on the performance of extra work by the Supplier. Any such extras must have been approved in writing by BPI and, failing such approval; no payment shall be made in respect of same.

5. Payment

5.1 Payments shall be made to the Supplier by BPI, to the limits established in section 4 of this Agreement, in accordance with invoices from the Supplier detailing work time and expenses incurred and based on completion and the tasks outlined in the Supplier's Proposal and Project Schedule. Invoices submitted on a monthly basis for simply payment purposes will not be allowed. Terms of payment of any such invoice shall be net 30 days. **All invoices shall reference BPI's RFP number (15-17). Failure to identify the RFP number on an invoice may result in delay of payment.**

5.2 Progress payments for the Services performed by the Supplier shall be made only where expressly agreed in writing by BPI. A claim for a progress payment made by the Supplier shall not include any aspect of the Services not yet fully and properly performed.

5.3 If any Services under the Agreement are included by the Supplier in its progress claims as partially or fully completed, but are not completed in accordance with the Agreement or are not otherwise completed to BPI's satisfaction, BPI may withhold from payment the total amount payable, or a part thereof, for those Services until they are completed or corrected to its full satisfaction of BPI.

5.4 Where a contingency allowance is provided for in the Agreement, the Supplier shall not be entitled to payment of the whole or any part of that amount, except to the extent that it can be shown that extra or additional Services have been carried out by the Supplier beyond that contemplated within the Agreement, and those extra Services have been approved, in advance, by BPI's Project Manager or contract representative as set out in the Agreement, or in default of such a provision, BPI's President & C.E.O.

6. Insurance Requirements

6.1 Throughout the term of the Agreement, the Supplier covenants and agrees at all times during the term hereof to take out and keep in full force and affect a policy(s) of:

6.1.1 **Commercial General Liability Insurance**, insuring against damage or injury to persons or property with limits of not less than $5,000,000.00 per occurrence or such greater amount as BPI may from time to time request or other types of policies appropriate to the work as BPI may reasonable require. In addition, any sub consultants have to be approved by BPI before any work is done and the following insurance and indemnification requirements and clauses apply. The insurance policy shall:

a. Include as additional insured "Brantford Power Inc.";

b. Contain a cross-liability clause, severability of interests clause endorsement;

c. Contain a clause including Contractual Liability coverage arising out of the contract or agreement;

6.1.2 **Automobile Liability Insurance** that complies with all requirements of the current legislation of the Province of Ontario, having an inclusive limit of not less than $2,000,000.00 per occurrence or such greater amount as BPI may from time to time request, in respect of the use or operation of licensed vehicles owned or leased by the Supplier for the provisions of Services;

6.1.3 **Non-Owned Automobile Liability Insurance** in standard form having an inclusive limit of not less than $2,000,000.00 per occurrence or such greater amount as BPI may from time to time request, in respect of the use or operation of vehicles not owned by the Supplier for the provisions of Services;

6.1.4 **Professional Liability Insurance (Errors and Omission)** is required and will have an inclusive limit of not less than $2,000,000 or, alternatively, the Supplier shall purchase and maintain in force for the duration of the project, single project Professional Errors & Omissions Liability Insurance with limits dedicated to the Project and having an inclusive limit of not less than $2,000,000 per claim.

6.2 Proof of insurance will be submitted by way of an executed Certificate of Insurance in a form satisfactory to BPI each year or ten (10) days prior to renewal of policy. All requested lines of coverage to be shown on the Certificate. The Supplier shall neither perform nor be remunerated for any Services under this Agreement unless and until said insurance certificate has been provided and approved by BPI.

6.3 All such insurance policies shall stay in force and If cancelled or changed in any manner, that would affect BPI as outlined in coverage specified herein for any reason, thirty (30) days prior written notice by mail or facsimile transmission will be given by the insurer(s) and forwarded to the attention of BPI's project manager.

6.4 It shall be the sole responsibility of the Supplier to determine what additional insurance coverage, if any, are necessary and advisable for its own protection and/or to fulfil its obligation under this agreement. Any such additional insurance shall be maintained and provided at the sole expense of the Supplier.

7. Indemnification

7.1 The Supplier shall indemnify and save harmless BPI, its employees, agents, successors, members and assigns, from and against all actions claims and demands whatsoever which may be brought against or made upon BPI and against all losses, liability, judgments, claims, costs, demands or expenses which BPI may sustain, suffer, or be put to resulting from or arising out of the Supplier's failure to exercise reasonable care, skill or diligence in the performance or rendering of any work or service required hereunder to be performed or rendered by the Supplier.

7.2 Without limiting the generality of the foregoing, the Supplier hereby agrees to well and truly save, keep harmless and fully indemnify BPI, its employees, agents, successors and assigns, from and against all actions, claims and demands whatsoever which may be brought against or made upon BPI, its successors and assigns, for the infringement of or use of any intellectual property rights including any copyright or patent arising out of the reproduction or use in any manner of any plans, designs, drawings, specifications, information, negatives, data, material, sketches, notes, documents, memoranda, or computer software furnished by the Supplier in the performance of this Agreement.

7.3 For the purposes of this section, "costs" shall mean those costs awarded in accordance with the order of a court of competent jurisdiction, the order of a board, tribunal or arbitrator or costs negotiated in the settlement of a claim or action.

7.4 All goods and services provided to BPI pursuant to this agreement, including information, software and other intellectual property, shall be fully warranted against defects in accuracy, material and workmanship (as applicable) for a warranty period which commences immediately upon the supply and delivery of the goods and services, and which terminates one year following the total completion of this Agreement unless stated otherwise in the specifications.

8. WSIB

8.1 The Supplier prior to commencing the Project, Services or supply,

(a) shall submit to BPI an original Clearance Certificate from the Ontario Workplace Safety and Insurance Board and shall provide additional certificates with respect to such coverage as often as BPI deems necessary during the term of the Agreement to ensure continued good standing with the Workplace Safety and Insurance Board; or

(b) furnish proof in a form satisfactory to BPI from the Workplace Safety and Insurance Board that the Supplier does not require Workplace Safety and Insurance Board insurance, but in such a case if the Supplier changes its status during the term of the Agreement so that such coverage is required, the Supplier shall immediately provide BPI with the certificate required under clause (a).

8.2 Where a substantial portion of the work to be done under the Agreement is to be carried out by a sub consultant, BPI may require the Supplier to furnish the same evidence as provided under subsection (1).

9. Supplier Conflict of Interest, etc.

9.1 In performing the duties, providing advice and exercising all other rights and discretion associated with its role as a Supplier, the Supplier shall,

(a) act diligently, honestly and in good faith and in the best interests of BPI;

(b) to the best of its ability make every effort to promote the interests and reputation of BPI; and

(c) to the best of its ability assist BPI in achieving its objectives and goals.

9.2 The Supplier shall act ethically and fairly in all of its dealings with BPI and all elected or appointed officials, officers, employees and independent contractors of BPI, and co-operate with them in respect of the discharge of their duties to BPI.

9.3 The Supplier shall not act in any case where there may be any conflict of interest between it (or any of its directors, officers, employees) and BPI. The Supplier shall notify BPI of and fully disclose to BPI, in writing and immediately upon same becoming known to the Supplier, any potential or actual conflict of interest that may arise or has arisen prior to the execution of this Agreement or during the performance of its duties under the Agreement.

10. Assignment and Subconsulting

10.1 The Supplier shall not assign, transfer or encumber in any manner or part this Agreement without the prior written consent of BPI. Any attempt to assign, transfer or encumber any of the rights, duties or obligations of this Agreement without such consent of BPI is void.

10.2 No subconsulting by the Supplier shall relieve the Supplier of any responsibility for the full performance of all obligations of the Supplier under the Agreement. Notwithstanding the approval of any subconsultants by BPI, the Supplier shall be fully responsible for every subconsultant's activities, works, Services and acts or omissions.

11. Confidential Information

11.1 Upon completion or other termination of this Agreement, the Supplier shall return to BPI all written or descriptive matter, including but not limited to drawings, descriptions, or other papers, documents or any other material, which contains any confidential information. Except as expressly provided in this paragraph, no confidential information shall be disclosed without the approval in writing of BPI, and:

(a) the Supplier shall hold all confidential information obtained in trust and confidence for BPI and shall not disclose any such confidential information, by publication or other means, to any person, company or other government agency nor use same for any other project other than for the benefit of BPI as may be authorized by BPI in writing;

(b) any request for such approval by BPI shall specifically state the benefit to BPI of disclosure of confidential information;

(c) any use of the confidential information shall be limited to the express purposes as set out in the approval of BPI; and,

(d) the Supplier shall not, at any time during or after the term of this agreement, use any confidential information for the benefit of anyone other than BPI.

12. Right of Ownership and Use

12.1 Upon completion or other termination of this Agreement, all information, negatives from original photography, computer software, data, material, sketches, plans, designs, notes, documents, memoranda, specifications or other paper writing gathered, assembled, or prepared by the Supplier, its employees, servants, subconsultants or agents (hereinafter collectively referred to as "the material") shall become the sole property of BPI including copyright with respect to all such material. The Supplier shall execute any documents required to give effect to the foregoing.

12.2 The Supplier waives in whole and in part any and all moral rights arising under the Copyright Act in the material as against BPI and anyone claiming rights of any such nature from or through BPI. Further, the Supplier represents and warrants that its employees, servants, subconsultants and agents have waived or shall waive in whole and in part any and all moral rights arising under the Copyright Act in the material as against all parties, including the Supplier and BPI, and anyone claiming rights of any such nature from or through BPI.

13. Accessibility For Ontarians With Disabilities Act, 2002 And Barrier Free Design Guidelines

13.1 Brantford Power Inc. is committed to providing equal treatment to people with disabilities with respect to the use and benefit of BPI services, programs, and goods in a manner that respects their dignity and that is equitable in relation to the broader public.

13.2 Effective 1 January 2010, third party contractors who deal with the public or other third parties on behalf of BPI, as well as Suppliers who participate in developing BPI policies, practices or procedures governing the provision of goods and services to members of the public or other third parties, must conform with the Accessibility Standards for Customer Service, O. Reg. 429/07 (Appendix A) (“Regulation”), under The Accessibility for Ontarians With Disabilities Act, 2005 (AODA).

13.3 Pursuant to Section 6 of the Regulation, the Supplier shall ensure that all of its employees, agents, volunteers, or others for whom it is at law responsible, receive training about the provision of the goods and services contemplated herein to persons with disabilities. Such training shall be provided in accordance with Section 6 of the Regulation and shall include, without limitation, a review of the purposes of the Act and the requirements of the Regulation, as well as instruction regarding all matters set out in Section 6 of the Regulation. Where requested by BPI, the Supplier shall provide written proof that employees working with BPI staff and/or public have been trained as required under the act as well as any documentation regarding training policies, practices and procedures.

14. Supplier's Default and BPI's Remedies

14.1 The provisions of this section are in addition to any other rights, privileges and remedies to which BPI is entitled by Law, in equity or otherwise in the Agreement.

14.2 The following shall constitute, without limitation, Acts or Events of Default ("Default") by the Supplier:

(a) where the Supplier fails or neglects to commence or to proceed with the provision of Services diligently and at a rate of progress that in the opinion of BPI will ensure entire completion within the time provided for in the Agreement;

(b) where BPI determines reasonably that the Supplier has abandoned its duties with respect to the Project or failed to observe and perform any of the provisions of the Agreement, the determination of which BPI shall be the sole judge;

(c) where the Supplier fails to comply with and maintain in good standing any insurance policies, professional certificates, permits, licences or approvals required by the Agreement or commits any acts or omissions that jeopardizes or may jeopardize these policies, permits, licences or approvals;

(d) where the Supplier fails to comply with or observe or perform, or breaches or violates, any provision, term, covenant, warranty, condition, responsibility and/or obligation of the Agreement;

(e) where the Supplier fails to comply with any Law;

(f) where the Supplier fails to comply with any instruction or direction of BPI;

(g) where the Supplier defaults in the completion of the Services within the time limit under the Agreement or within a BPI-extended time limit;

(h) where the Supplier makes an assignment for the benefit of creditors or becomes bankrupt or insolvent, or makes a proposal to its creditors.

14.3 Without restricting, limiting, precluding or otherwise prejudicing any other right, privilege or remedy of BPI provided in the Agreement or by Law or in equity, in the event that the Supplier has committed an Act of Default or an Event of Default has occurred, BPI may provide written notice ("Default Notice") to the Supplier to the effect that if the Supplier does not completely remedy the Default to the satisfaction of BPI within three (3) Business Days of delivery of the Default Notice, or such other period of time as may be specifically provided for under the Agreement or otherwise granted by BPI in writing, in its absolute discretion, then BPI may terminate the Agreement and/or the Services of the Supplier immediately.

14.4 If the Default is not completely remedied to the satisfaction of BPI in accordance with subsection 14.3, BPI may terminate the Agreement immediately and enforce any performance bond, letter of credit or other performance security provided by the Supplier (where applicable).

14.5 A waiver of a Default shall not extend to, or be taken in any manner whatsoever to affect the rights of BPI with respect to any subsequent default, whether similar or not.

14.6 The remedies provided in this Agreement are in addition to all other legal, equitable or statutory remedies to which BPI is otherwise entitled, as well as any other remedies stipulated in the Agreement, and the taking of any one remedy shall not preclude the taking of any other remedy.

14.7 If BPI terminates the Agreement as a result of an Act or Event of Default, in addition to any other rights, privileges and remedies it is entitled to, BPI may:

(a) take possession of all of the work in progress, supplies, goods and materials, and complete the Services by whatever means BPI may deem appropriate under the circumstances;

(b) withhold any further payments to the Supplier until the completion of the Services and the expiry of all obligations; and

(c) recover from the Supplier loss, damage and expense incurred by BPI or may be incurred by BPI by reason of the Supplier's default (which may be deducted from any monies due or becoming due to the Supplier, with any balance remaining to be paid by the Supplier to BPI).

14.8 Unless BPI otherwise agrees in writing and without limiting any other provision of this section, the failure, refusal or neglect by the Supplier to deliver the Services in a diligent manner within the time specified or to promptly replace, remedy or correct the Supplier's performance and/or Services as required pursuant to the Agreement shall be deemed to constitute an authority for BPI to purchase and/or replace the Services in question on the open market. The Supplier shall forthwith reimburse BPI for all of its extra costs and expenses incurred to purchase and/or replace such Services, and BPI's internal costs and any delay costs.

15. Compliance with Laws

15.1 The Supplier shall comply with all Federal, Provincial and Municipal Laws and regulations in performing the Agreement including, without limitation, the Occupational Health and Safety Act, or any successor legislation, as applicable, and to provide to BPI, upon request, reports confirming such compliance.

15.2 The Supplier shall comply with the Human Rights Code and refrain from acts of discrimination and harassment in the same manner as would apply to employees of BPI pursuant to its Code of Conduct.

16. Governing Law

16.1 This Agreement shall be governed by the laws of the Province of Ontario and the laws of Canada, as applicable to the matters herein. Any action or other legal proceeding arising under or with respect to the Agreement will be determined by a court of (or other forum) of competent jurisdiction within the Province of Ontario.

17. Agreement Non Exclusive

17.1 Unless otherwise expressly provided in the RFP or any Addendum thereto, no Agreement shall be deemed to confer upon the Supplier an exclusive right to supply those Services to BPI for the Project or otherwise.

18. Notification

18.1 Any notice required, or permitted to be given, under this agreement shall be given as follows:

Brantford Power Inc.
84 Market St.
Brantford, Ontario
N3T 2Z7
Attention: Corporate Secretary

Name of Supplier
Address of Supplier
City, Province
Postal Code
Attention:

18.2 Either party may change its address by notice given in accordance with this section. Notices may be delivered personally, in which case they shall be effective immediately, or through regular mail, in which case they shall be effective on the fifth day following mailing.

19. Interpretation

19.1 Words importing the masculine gender shall include the feminine and neuter, and the singular shall include the plural where the meaning or context so requires.

20. Complete Agreement

20.1 This Agreement and the Agreement Documents attached thereto, constitutes the complete and exclusive statement of the agreement between the parties which supersedes all other communications between the parties relating to the subject matter of this Agreement.

21. Relationship of the Parties

21.1 Nothing in this Agreement shall be constructed to place the parties in the relationship of partners, joint venturers, principal/agent, or employer/employee. The Supplier also acknowledges that it has no authority to bind BPI to any obligation of any nature or any kind, in law or in equity.

22. Successors and Assigns

22.1 This Agreement shall enure to the benefit of and be binding on the parties hereto, and their respective heirs, successors and assigns. Provided, however, that the Supplier shall not assign this Agreement nor any interest therein without the prior written consent of BPI, and for the purposes of this Agreement, assignment shall include any transfer in the majority ownership or controlling interest in the Supplier, whether through the sale of shares, direct acquisition of assets or otherwise.

IN WITNESS WHEREOF the parties hereto have hereunto affixed their corporate seals attested to by the hands of their respective proper signing offices in that behalf duly authorised.

Signed, sealed and delivered as of the date first above written.

<SUPPLIER LEGAL NAME>

Per: ________________________________

Date: ________________________________

I/ we have the authority to bind the Supplier.

BRANTFORD POWER INC.

Per: ________________________________

Date: ________________________________
<Name, Title>

Per: ________________________________
<Name, Title>

Date: ________________________________

APPENDIX B – SUBMISSION FORM

1. Proponent Information

Please fill out the following form, naming one person to be the proponent's contact for the RFP process and for any clarifications or communication that might be necessary.	
Full Legal Name of Proponent:	
Any Other Relevant Name under which Proponent Carries on Business:	
Street Address:	
City, Province/State:	
Postal Code:	
Phone Number:	
Fax Number:	
Company Website (if any):	
Proponent Contact Name and Title:	
Proponent Contact Phone:	
Proponent Contact Fax:	
Proponent Contact Email:	

2. Acknowledgment of Non-binding Procurement Process

The proponent acknowledges that the RFP process will be governed by the terms and conditions of the RFP, and that, among other things, such terms and conditions confirm that this procurement process does not constitute a formal, legally binding bidding process (and for greater certainty, does not give rise to a Contract A bidding process contract), and that no legal relationship or obligation regarding the procurement of any good or service shall be created between BPI and the proponent unless and until BPI and the proponent execute a written agreement for the Deliverables.

3. Ability to Provide Deliverables

The proponent has carefully examined the RFP documents and has a clear and comprehensive knowledge of the Deliverables required. The proponent represents and warrants its ability to provide the Deliverables in accordance with the requirements of the RFP for the rates set out in the completed Pricing Form (Appendix C).

4. Non-binding Pricing

The proponent has submitted its pricing in accordance with the instructions in the RFP and in the Pricing Form (Appendix C). The proponent confirms that the pricing information provided is accurate. The proponent acknowledges that any inaccurate, misleading or incomplete information, including withdrawn or altered pricing, could adversely impact the acceptance of its proposal or its eligibility for future work.

5. Addenda

The proponent is deemed to have read and taken into account all addenda issued by BPI prior to the Submission Deadline. The proponent is requested to confirm that it has received all addenda by listing the addenda numbers, or if no addenda were issued by writing the word "None", on the following line: ____________________________. If this section is not completed, the proponent will be deemed to have received all posted addenda.

6. No Prohibited Conduct

The proponent declares that it has not engaged in any conduct prohibited by this RFP.

7. Conflict of Interest

For the purposes of this RFP, the term "Conflict of Interest" includes, but is not limited to, any situation or circumstance where:

(a) in relation to the RFP process, the proponent has an unfair advantage or engages in conduct, directly or indirectly, that may give it an unfair advantage, including but not limited to (i) having, or having access to, confidential information of BPI in the preparation of its proposal that is not available to other proponents, (ii) communicating with any person with a view to influencing preferred treatment in the RFP process (including but not limited to the lobbying of decision makers involved in the RFP process), or (iii) engaging in conduct that compromises, or could be seen to compromise, the integrity of the open and competitive RFP process or render that process non-competitive or unfair; or

(b) in relation to the performance of its contractual obligations under a contract for the Deliverables, the proponent's other commitments, relationships or financial interests (i) could, or could be seen to, exercise an improper influence over the objective, unbiased and impartial exercise of its independent judgement, or (ii) could, or could be seen to, compromise, impair or be incompatible with the effective performance of its contractual obligations.

For the purposes of section (a)(i) above, proponents should disclose the names and all pertinent details of all individuals (employees, advisers, or individuals acting in any other capacity) who (a) participated in the preparation of the proposal; **AND** (b) were employees of BPI within twelve (12) months prior to the Submission Deadline.

If the box below is left blank, the proponent will be deemed to declare that (a) there was no Conflict of Interest in preparing its proposal; and (b) there is no foreseeable Conflict of Interest in performing the contractual obligations contemplated in the RFP.

Otherwise, if the statement below applies, check the box.

- ❑ The proponent declares that there is an actual or potential Conflict of Interest relating to the preparation of its proposal, and/or the proponent foresees an actual or potential Conflict of Interest in performing the contractual obligations contemplated in the RFP.

If the proponent declares an actual or potential Conflict of Interest by marking the box above, the proponent must set out below details of the actual or potential Conflict of Interest:

____

____

____

____

8. Disclosure of Information

The proponent hereby agrees that any information provided in this proposal, even if it is identified as being supplied in confidence, may be disclosed where required by law or by order of a court or tribunal. The proponent hereby consents to the disclosure, on a confidential basis, of this proposal by BPI to the advisers retained by BPI to advise or assist with the RFP process, including with respect to the evaluation this proposal. In addition, the proponent consents to the disclosure of contractual information, including pricing information, which may be disclosed to the OEB and, accordingly, may become part of the public record.

______________________________	______________________________
Signature of Witness	Signature of Proponent Representative
______________________________	______________________________
Name of Witness	Name of Proponent Representative
	______________________________
	Title of Proponent Representative
	______________________________
	Date
	I have the authority to bind the proponent.

APPENDIX C – PRICING FORM

1. Instructions on How to Complete Pricing Form

(a) Rates shall be provided in Canadian funds, inclusive of all applicable duties and taxes except for HST, which should be itemized separately.

(b) Rates quoted by the proponent shall be all-inclusive and shall include all labour and material costs, all travel and carriage costs, all insurance costs, all costs of delivery, all costs of installation and set-up, including any pre-delivery inspection charges, and all other overhead, including any fees or other charges required by law.

(c) Appendix C – Pricing Form (Schedule of Prices) is located on the FTP Site. For each pricing component (e.g. Hosted Solution – production; test environment; disaster recovery), proponents may detail the module subsections into separate item costs if desired. If the item is not priced in a detailed subsection fashion, the total module base cost shall be inserted into the "Base FIS System Price" and shall be deemed to include all module subsection costs.

(d) The contract price shall include a price for the provisional item(s) as identified in the Pricing Form – Schedule of Prices. BPI reserves the right to delete any or all provisional items through the negotiation period should it be determined by BPI that the item is not required for the project.

(e) The contract price shall be exclusive of the alternate item(s) identified in the Pricing Form. BPI reserves the right to delete the proposed hosted solution and replace the project in its entirety with an on premise solution should it be determined by BPI that the on premise solution is more beneficial for the project. The alternate priced 'on premise' solution will only be considered from the top two ranked proponents.

Note: Mathematical errors in the extension of unit prices may be corrected by BPI. The unit prices will be deemed to be correct and only errors in the multiplication or addition of unit prices will be corrected.

2. Pricing Form

Summary of Prices – Hosted Solution	
Hosted Model Total Price - Production	$
Hosted Model Total Price - Test	$
Hosted Model Total Price - Disaster Recovery	$
Contract Price	**$**

3. Alternate Price

Summary of Alternate Price ‘On Premise’ Solution	
Licensed ‘on premise’ Total Price - Production	$
Licensed ‘on premise’ Total Price - Test	$
Licensed ‘on premise’ Total Price - Disaster Recovery	$
Alternate Price ‘On Premise’ Solution Total	**$**

PROPONENT’S NAME: ____

APPENDIX D – RFP PARTICULARS

A. THE DELIVERABLES

BPI's preference is for a non-ownership "Hosted" FIS solution. In the context of this RFP, a "Hosted" solution will be perceived to be one where the vendor will own the licenses for the software, and will own the hardware. The solution fee shall include, but not be limited to, applicable integration, resources, and travel costs, in addition to any applicable start-up costs associated with the implementation of the solution. BPI is also seeking alternate pricing for an owned 'on premise' solution.

For any hosted solution, the data centre must reside in Canada. Data cannot cross the Canadian border for any reason.

BPI considers the following list of items as required to successfully satisfy the intent of this RFP:

- Project management, system design, commissioning, and training;
- Creation and implementation of all required interfaces including technical expertise required to establish communications between the FIS and BPI's back office systems;
- System security (i.e., detailed security parameters to protect all information collected and stored);
- Service levels and value added services;
- Applicable costs, pricing and rates;
- Conversion assistance to convert from the existing FIS solution(s) to the new FIS;
- Detailed reporting functionality;
- Business Intelligence; and
- Ongoing technical support and updates.

Complete Solutions Specifications and Response Criteria prepared by the project consultant, Util-Assist, can be found on the FTP site.

B. MATERIAL DISCLOSURES

Conditions of Award

The selected proponent must satisfy the following conditions and provide the following information within the contract negotiation period:

- Certificate of Insurance for the coverage and limits as set out in the agreement, naming Brantford Power Inc. as additionally insured;
- WSIB clearance certificate confirming the proponent is registered and has an account in good standing; and

C. MANDATORY TECHNICAL REQUIREMENTS

N/A

D. FTP SITE

BPI has established a FTP site for this project. The documents contained on the FTP site form part of the contract. Documents may be accessed using the following web address, username and password:

https:/filesend.brantford.ca

Username: **fs_rfp15-17** Password: **WSdHEWEc**

E. DOCUMENT INDEX

The Document Index for this RFP consists of 4 separate attachments, which are located on the FTP site, as follows:

1. RFP Document
2. Functional Requirement Workbook
3. Solution Specifications and Response Criteria
4. Appendix C – Pricing Form (Schedule of Prices)

F. DEFINITIONS

(a) “Hosted” will mean that the proponent physically hosts the solution, and also owns the hardware and software licenses.

(b) “On-Premise” refers to a solution where BPI will physically host and own the hardware and software licenses.

APPENDIX E – EVALUATION CRITERIA AND RANKING METHOD

A. RATED CRITERIA

The following is an overview of the categories and weighting for the rated criteria of the RFP. Proponents who do not meet a minimum threshold score for a category will not proceed to the next stage of the evaluation process.

Section	Rated Criteria Category	Weighting (points)	Minimum Threshold
	Functional Requirement Workbook	5 points	N/A
Solution Specifications:			
1.	Prerequisites	Pass/Fail	Must pass all aspects
2.	Proponent Company Information	3 points	N/A
3.	Technical Solution - FIS Functionality	57 points	N/A
	Total Points for Rated Criteria	***65 points***	***45.5 points***
	Pricing	30 points	N/A
	Demonstration	5 points	N/A

Suggested Proposal Content for the Evaluation of Rated Criteria

Specific evaluation criteria are written into the Solution Specifications and Response Criteria located on the FTP site. It is the proponent's responsibility to ensure that all criteria requirements listed have been addressed to the level of detail required and included in the submission response.

Each specification subsection identifies a proposal requirement indicator to assist proponents with the level of detailed response required..

Proposal Requirements Indicators

Proposal requirement indicators indicate whether the proponent should provide:

- information (I);
- a statement of compliancy (C); or
- a statement of compliancy <u>and</u> information (CI)

pertaining to the functionality of the proposed product.

Proponents are required to list the questions followed by and their subsequent response to that specific question.

Indicator	Requirement
(I)	When an (I) has been included with the section heading, BPI requires information regarding the proposed system's functionality to satisfy the RFP requirement.
(C)	When a (C) has been included with the section heading, BPI requires a statement of compliancy from the Proponent. Within the submission documentation, the Proponent is required to state the proposed product's compliancy with the requirement by stating Fully Compliant, Project Compliant, Partially Compliant, or Not Compliant.
(CI)	When a (CI) has been included with the section heading, BPI requires both a statement of compliancy, and information regarding the proposed system's functionality to accommodate the RFP requirement.

In indicating compliancy to a particular requirement, the proponent is to use one of the following terms:

- **Fully Compliant** – Proponent confirms that the functionality required is currently in its product in a live environment with other customers.
- **Project Compliant** – Proponent confirms that the functionality required is in beta testing with another customer and scheduled to be part of the base product in a specified future version or the proponent intends to build the functionality into the product to meet the specifications.
- **Partially Compliant** – Proponent confirms that some of the functionality required is in its current product in a live environment but may be missing a portion of the required functionality or the proponent confirms that the functionality required is in beta testing with another customer and scheduled to be part of the base product in a specified future version.
- **Not Compliant** – Proponent confirms that this functionality is not part of its current product in a beta or live environment with other customers.

In instances where the product is Partially Compliant or Not Compliant, the proponent is required to state plans (complete with development timeline) to bring their product into compliancy.

B. PRICING

The pricing points for each proponent will be determined based on a relative pricing formula using the prices set out in the Pricing Form. Each proponent will receive a percentage of the total possible points allocated to price for the particular category it has bid on, which will be calculated by dividing that proponent's price for that category into the lowest bid price in that category. For example, if a proponent bids $120.00 for a particular category and that is the lowest bid price in that category, that proponent receives 100% of the possible points for that category (120/120 = 100%). A proponent who bids $150.00 receives 80% of the possible points for that category (120/150 = 80%), and a proponent who bids $240.00 receives 50% of the possible points for that category (120/240 = 50%).

Lowest price
-------------------   x   Total available points = Score for second-lowest price
Second-lowest price

Lowest price
-------------------   x   Total available points = Score for third-lowest price
Third-lowest price

And so on, for each proposal.

C. DEMONSTRATION

Up to three proponents who achieve or exceed the minimum threshold in the rated criteria combined with the pricing points will be invited to provide a demonstration at a City of Brantford facility. BPI reserves the right, in their sole, complete and unfettered discretion, to increase the number of proponents who are invited to provide a demonstration.

The demonstration will take no longer than 180 minutes in total, including questions and discussion.

The demonstration will become a component of the proposal; therefore proponents are requested to bring at least one hardcopy and one electronic copy of the demonstration materials.

The demonstration will be scored. Demonstration scoring criteria will be provided to proponents at the time the demonstrations are scheduled.

D. FINAL EVALUATION AND RANKING METHOD

The ranking of proponents will be based on the total score calculated by adding total points obtained by a proponent for each of the evaluation categories.

Rated Criteria Score + Pricing Score + Demonstration Score = Total Score.

Attachment 4-SEC-18-C.2: FIS

BEST AND FINAL OFFER

Section 1 – General Information			
RFP No. & Title:	RFP 15-17 Provision of Financial Information System for Brantford Power Inc.		
Closing Date:	Thursday, December 3, 2015	Closing Time:	3:00:59 p.m.
Submission Address:	Purchasing Division - 1 Market Square, Suite 120 , Brantford, ON N3T 6C8		
City Representative:	Eva Cislo, Buyer	Phone No:	(519)759-4222 ext.5194
Email:	evacislo@brantford.ca	# of pages included with this BAFO	11

Section 2 – BAFO Process

1. This Best and Final Offer package (the "BAFO") has been created to provide top ranked proponents with one final opportunity to provide proposal improvements.
2. The BAFO package released is identical for all top ranked proponents.
3. As part of this BAFO process, Brantford Power Inc. (BPI) will provide each top ranked proponent with any additional information and will seek further information and proposal improvements. This may be completed via a dialogue session with BPI to ensure any concerns have been addressed and that the proponents have the clarity they require in order to provide the most accurate proposal.
4. Questions arising from the BAFO requirements shall be directed to the City Purchasing Representative by **Wednesday, November 25, 2015 @ 4:00 p.m.**
5. Each top ranked proponent is invited to revise its initial proposal and submit its BAFO to BPI.
6. BAFO submissions shall include 5 hard copies and 1 electronic copy of the BAFO Submission Form, the proponent's revised proposal and BAFO pricing (to be completed on the Pricing Form provided).
7. Each BAFO will be evaluated and assigned a final ranking using the same criteria and process as set out in the initial RFP.
8. The top ranked proponent based on the evaluation of the BAFOs will receive a written invitation to enter into a final round of negotiations to finalize the agreement with BPI.
9. BAFOs submitted after the deadline may not be accepted.

Section 3 – Proponent Information			
Legal Name of Proponent:			
Business Address:			
Phone No.:		Email:	
Contact Person:		Title:	
Signature:		Date:	

Section 4 – BAFO Requirements

This request is to acquire a best and final offer. A proponent's offer should integrate the previous response to the RFP and any changes listed below.

Brantford Power Inc. encourages the proponent to supply more competitive prices. The proponent should submit its most competitive prices per the BAFO Pricing Form of this request for BAFO.

NOTE: This proposal is still in the evaluation period. During this period and prior to award, possession of the BAFO, original proposal response and accompanying information is limited to the Purchasing Division and to Brantford Power Inc. members responsible for participating in the evaluation. Proponents who attempt to influence the evaluation process or not abide by the BAFO process will be in violation of purchasing process and their offer will not be further evaluated or considered.

1.0 Implementation Experience

RFP 15-17 Reference

BPI's RFP 15-17 did request that Proponents provide information regarding their experience implementing the proposed solution; **3.21.1 Implementation Experience (I)** asked proponents to describe their experience in the Ontario Local Distribution Company (LDC) market. The Guiding Principles explained in RFP Section 1 were meant to provide insight into BPI's desire to use out-of-the-box solutions, and follow Best Practices wherever possible. To accomplish this, vast experience in the unique Ontario electricity LDC sector market is considered a critical qualifying asset.

BAFO Requirement

BPI is seeking an understanding of each proponent's experience both inside and outside the Ontario electricity LDC market. As part of the BAFO response, BPI would request that the proponent's explain the role that they provided in each of the deployments referenced as part of their RFP response during the last ten years. Where such Ontario LDC experience is limited, the proponent should clearly address how they have mitigated or addressed this limitation in all elements of their BAFO.

To be clear, BPI understands that there is a:

- **Technical component** to each implementation, where the software solution and its features forms the Technical Component.
- **Software Implementation component** to each implementation, where the proponent (or a subcontractor to the proponent) is engaged with the utility for the purpose of deploying the software solution.
- **Hosting Service Provider component** to this particular bid response, due to the nature of BPI's preference to procure a hosted solution. It is assumed by BPI that the Hosting Service Provider would house the hardware component of the Technical Component, and provide expertise to assist with hardware and software maintenance, ensure system availability, possibly assist with security and/or user administration, etc.

Reference 3.21.1 and 3.21.2

As part of the BAFO response, BPI requests that the proponent be explicit about their role in previous deployments of their proposed solution in a hosted environment clearly outlining their experience with the three elements outlined above in providing a complete FIS solution to LDC's in Ontario.

BPI seeks providers with ample experience in the Ontario electricity LDC market in all respects of the solution, but understands that the proponent may specialize in some aspect of the overall solution. In those circumstances, details must be provided on how the proponent intends to address limited or no LDC experience in any of the three solution components outlined above. Where there may be reliance on subcontractors to deliver elements that the proponent has limited direct LDC experience, the proponent should clearly outline in the BAFO the specific LDC experience any subcontractors will bring to the solution that will complement those provided by the proponent.

It should be noted that only proponents who have demonstrated that the technical component of the overall solution meets BPI requirements have been invited to participate in the BAFO process. As a result of the clarification required by this section, BPI will determine the level of risk and internal costs associated with a solution provider due to a level of inexperience in the Ontario LDC market in one or more element of the proposed solution. This may preclude BPI from considering such a proponent unless BPI is satisfied that the BAFO and ultimate contractual arrangements clearly address and fully mitigate such risks for BPI.

2.0 Project Deliverables

RFP 15-17 Reference

BPI's RFP 15-17 did request that proponents provide sample implementation plans in section **3.21 Implementation of the FIS (I).** The requested project plans are intended to allow BPI to gain an understanding of the proponent's approach, as well as their experience implementing the proposed solution. From the material submitted, BPI would also look to understand their own resource requirements, as assumed by the proponent's plans.

BAFO Requirement

BPI requests the proponent's, in their BAFO submission, provide a full RACI, Gantt and Time Task Matrix organized by modules. BPI expects that significant portions of the original submission will be re-submitted for the BAFO process, but that the reorganization of the information, improved definition of tasks and revised timelines will provide clarity to the proponent's intended process for implementing the solution, as well as providing BPI with the ability to better define internal resource requirements that are anticipated by the proponents to be provided through the implementation of the solution. Proponents should specify what modules are to be implemented concurrently and which ones will be phased based on industry best practices leading to an outcome where the proposed solution, including all modules, are successfully implemented no later than December 31, 2016.

Reference 3.21:

- Gantt Chart – a project schedule outlining key milestones and critical paths, including meetings and significant deliverables.
- Time Task Matrix – shall identify each task for the team members for the project and also the number of hours during each phase and major tasks. These should coincide with the Gantt Chart and RACI table. For any tasks that include work to be performed by BPI, the project plan must include an expected number of hours required by each BPI resource required to perform the work.
- Accountability will be properly defined through the plan at the task level. BPI requests that the proponents use RACI format for assigning accountability; where R indicates the role that is Responsible for completing that step in the process, A indicates the role that is accountable for ensuring the step is completed, C indicates the role that is Consulted prior to completion of the step, and I indicates the role that is Informed of the results once the step is completed.
  - Where the proponent intends to use or rely on subcontractors for any tasks, the proponent should provide details of the relationship with the subcontractor, the location of the subcontractor, what measures exist to ensure the tasks are completed in the manner expected by the proponent, and what contingency plans exist should the relationship with the subcontractor change during the course of the FIS engagement.
- Proponent's should include the testing functions and success criteria associated with Unit Testing, System Integration Testing (SIT), and User Acceptance Testing (UAT), etc., where:
  - Unit testing accounts for the testing components as each "wave" of the project plan is executed and completed; Unit Tests would be specific to the implemented module.
  - SIT testing accounts for the integration components of the FIS solution, ensuring that the integration with CIS, GIS, etc, is functioning as expected.

- o UAT is the final testing processes which are effectively end to end tests conducted by users of the system to ensure that the anticipated business processes for use of the implemented FIS solution function as expected.

- In addition to the above testing the plans should reflect additional testing such as performance testing, data conversion testing, disaster recovery testing, etc. as required or suggested by the proponent.
- The project plans should clearly define the anticipated process to cut-over to the new FIS solution as well as incorporate any/all anticipated resources required for implementation based on the following (but not limited to):
  - **Integration (Section 1.1)**
  - **Data Conversion (Section 1.2)**
  - **Test Plan (Section 1.3)**
  - **Business Process Documentation (Section 1.4):** The project plans must refer by module to the documentation and review of current business processes and the development, validation and transition to new business processes that will be required in the management of the new FIS solution.
  - **Training (Section 1.5):** The proponent should specify who should be trained and when the different training sessions will occur (e.g., training session for SMEs vs. for end users).

It is important to note that the RACI chart, Gantt Chart and Time Task Matrix submitted will become part of the contract that is negotiated with the preferred proponent. In this regard, BPI has provided a composite sample Project Plan and Integrated RACI charts to illustrate the level of detail by module the proponents are requested to provide. BPI will accept existing formats of the proponent provided they provide the same level of detail provided in the sample below.

.

FIS Project					Vendor		BPI / COB Resources											
					Project Manager	Technical	Project Sponsor		Project Manager		IT Manager		SME 1		SME 2		Other	
Module	Task	Vendor Responsibilities	BPI Responsibilities	Output	Role	Role	Role	Hrs	Role	Hrs	Role	Hrs	Role	Hrs	Role	Hrs	Role	Hrs
Payroll	Discovery				A	R			I	4	C	40	C	40				
Payroll	Functional Design				A	R			I	4	C	20	C	20				
Payroll	Data Conversion				A	R			I	4	C	80	C	40				
Payroll	Configuration				A	R			I	4	C	10	C	10				
Payroll	Change Managemet / Business Process Design				A	R			I	8	C	10	C	40				
Payroll	Tester Training				A	R			I	2	C	0	C	24				
Payroll	UT				A	R			I	4	C	0	C	5				
Payroll	SIT				A	C			A	4	C	0	R	40				
Payroll	UAT				A	C			A	4	C	0	R	40				
Payroll	Support Training Material				A	R			A	2	C	0	R	40				
Payroll	End User Training				A	R			A	4	C	0	R	80				

Figure 1: Sample Project Plan with Integrated RACI chart

2.1 Integration

RFP 15-17 Reference
BPI's RFP 15-17 did request that proponents provide information regarding integration with CIS in section **3.4.2 Integration with the CIS (CI).** Other sections of the RFP (e.g., 3.4.1, 3.4.3) also inquired as to the proponents experience with integration to other utility applications. As part of these sections, BPI was hoping to understand the proponent's experience with the anticipated integrations, the preferred process, and the anticipated BPI resource requirement to accommodate the conversion process. BPI notified FIS proponents (through Section 3.2.1) that BPI is also replacing their CIS system in the near term, and reminded FIS proponents (through Section 3.4.2 subsection iv) that two integrations to CIS would be required; 1 to make the proposed FIS "fit for purpose" in the existing operating environment, with the CIS integration being repeated when the new CIS is deployed.
BAFO Requirement
The goal that BPI hopes to achieve through the re-submission of information associated with the Integration process, is to ***comprehensively understand by module when applicable, the process and internal resource requirements*** associated with the integration of systems. Any training that is anticipated to be required to allow BPI resources to understand the integration process should be captured. The submission should also make it clear to BPI that the Proponent understands the complexities of the current operating environment.

2.2 Data Conversion

RFP 15-17 Reference
BPI's RFP 15-17 did request that proponents provide information pertaining to the Data Conversion process in sections **3.6.2 Data Conversion (I)** and **3.21.3 Data Conversion (I).** BPI is seeking to understand whether the proponent utilized tools to assist with conversion, and better understand the BPI resources that were assumed to be part of the conversion process. BPI attempted to clarify through section 3.2, that the current operating environment is not considered optimal, possibly creating some unique requirements in the data conversion process that would be required in moving to the proposed solution.
BAFO Requirement
BPI wishes to ***comprehensively understand the process and internal resource requirements*** associated with the data conversion process. To this end, proponents should include the following as part of their BAFO submissions: <u>Reference 3.1-3.5</u> • An understanding of the uniqueness of BPI's current operating environment and confirmation that the BAFO provides for all of the necessary tasks required for a successful transition from the existing complex system and business process environment to the new solution and is included with the price submission. <u>Reference - 3.6.2.3</u> • The number of years of history included in your price (minimum 5 years detailed history at the transaction level supplemented with remaining additional years of summarized history).

Reference - 3.6.2.4

- Any training that is anticipated to be required to allow BPI resources to understand the conversion tools should be captured.

2.3 Test Plan

RFP 15-17 Reference

BPI's RFP 15-17 did request that proponents provide information regarding the suggested plan for testing in section **3.6.3 System Acceptance Test Plan (I).** As part of this section, BPI is seeking an understanding of the proponent's experience with testing, standard test scripts which have been used, and the anticipated BPI resource requirement to accommodate the test process.

BAFO Requirement

The format for the Project Plans specified in section 2.0 of this document should result in the clarity that BPI seeks. The goal that BPI hopes to achieve through the re-submission of information associated with the test process, is to ***comprehensively understand the process and internal resource requirements*** associated with the testing of the solution. To provide this clarity, Proponents should provide test plans, and include as part of the Project Plan the anticipated hours to complete the testing for each of the resources assumed to be participating in the exercise.

2.4 Business Process Documentation

RFP 15-17 Reference

BPI's RFP 15-17 did request that proponents provide information regarding the development of business processes in section **3.21.4 Business Process Documentation for the FIS (I).** BPI is seeking to understand the proponent's experience with developing Business Process documentation that can assist BPI in training, testing and the improvement of existing processes as appropriate for the new solution.

BAFO Requirement

The original submissions did not provide BPI with clarity as it relates to the BPI resource requirement associated with the development of Business Processes. The format for the Project Plans specified in section 2.0 of this document should result in the clarity that BPI seeks. The goal that BPI hopes to achieve through the re-submission of information associated with the development of Business Processes is to ***comprehensively understand the process and internal resource requirements by module*** associated with the documentation and review of **current** business processes and the development, validation and transition to **new** business processes that will be required in the management of the new FIS solution. To provide this clarity, proponents should include, as part of the Project Plan and the BAFO, the required tools and anticipated hours to complete the documentation of **current and end state** business process documentation in a format that BPI could modify and maintain in the future.

2.5 Training

RFP 15-17 Reference
BPI's RFP 15-17 did request that proponents provide information regarding the anticipated process of training BPI resources on the use of the proposed solution in section **3.22 Training Requirements (I).** BPI is seeking to understand the proponent's plan for Training, at the modular level (i.e. the training and associated BPI resource requirement for each module of the solution).
BAFO Requirement
The format for the Project Plans specified in section 2.0 of this document should result in the clarity that BPI seeks. The goal that BPI hopes to achieve through the re-submission of information associated with training is to ***comprehensively understand the process and internal resource requirements*** associated with the training that will be required to successfully manage the proposed solution. To provide this clarity, proponents should include as part of the Project Plan the anticipated hours to complete the training. BPI requires that all training for SMEs and end users be incorporated into the BAFO. Although BPI would consider "Train the Trainer" arrangements in the future, given the expected significant changes in business processes and the desired go live date of December 31, 2016, BPI is not contemplating having the capacity for SMEs to take on this role during the transition to the proposed solutions. All training is to take place at a BPI facility, therefore, proponents should incorporate these costs into their Contract Price.

3.0 Risk Mitigation Section

RFP 15-17 included several questions that—in addition to accommodating functional requirements—were intended to provide BPI with important information about each proponent's level of experience, including their experience specifically in the Ontario market. BPI's decision to utilize a hosted service provider was made in large part to mitigate the resource requirement to manage the system given the multitude of projects that BPI will endeavour to complete in the coming months and years.

3.1 Service Levels and Remedies

RFP 15-17 Reference
BPI's RFP 15-17 did request that proponents provide information regarding proposed Service Levels and Remedies in the event of non-compliance. **Section 2.6 Standard Agreement (I)** showcases the general terms and conditions expected of the contract. Section **3.3.3 Disaster Recovery of the FIS solution (CI)** requested examples of standard Service Level Agreements and the remedies for failure to meet those SLAs while section **3.3.1 FIS Environments (I)** questioned if the same service levels would apply to the test environments as to the production environment.
BAFO Requirement

BPI understands that multiple utilities within Ontario currently utilize the hosted service model for FIS. The Financial Information System is a critical system for the utility, and BPI expects that solutions providers together with their utility partners would have implemented Service Level Arrangements to assist in contract management. BPI would ask that proponent's submit, as part of their BAFO package:

- Reference 2.6 & 3.3.3A Service Level Agreement that specifies the significant milestones that are expected to be part of the Project Plan during the deployment of the solution as well as service performance metrics that would define the level of service BPI will receive once the proponent's solution is in service. The Service Level Agreement should reflect all Remedies that would be considered appropriate in the event that milestones are not met during the deployment phase because of the proponent or identified service levels are not achieved once the proponent's solution has moved to the production environment.
- A Service Level Agreement to capture the Service Levels (and associated remedies) during the deployment and production phases would expect to include:
    - System Availability (for Production, Disaster Recovery, Test, etc) – as the FIS systems are critical to the functioning of the business – BPI expects the system average up time over a year to be a minimum of 99.95%
    - Product Support through a help desk or other suitable methods of access should at a minimum be available between 8 a.m. to 8 p.m. EST, Monday to Friday, excluding statutory holidays. The ability for BPI to schedule additional level of support services outside of these minimum BAFO service levels should be described.
    - Response time depending on the severity of the problem or for system administration requests is expected to meet the following minimum performance standards:
        - Priority 1 – Urgent and High Priority – 4 hours
        - Priority 2 – Medium Priority - 8 hours
        - Priority 3 – Low Priority - 24 hours

        To clarify further the above expectations, the following classification descriptions are provided to clearly delineate the nature of these incidents:

        Priority 1 – High
        - System Down (Software Application, Hardware, Operating System, Database)
        - Inability to process
        - Program errors without workarounds
        - Incorrect calculation errors impacting a majority of records
        - Aborted postings or error messages preventing data integration and update
        - Performance issues of severe nature impacting critical processes

        Priority 2 - Medium
        - System errors that have workarounds
        - Calculation errors impacting a minority of records
        - Reports calculation issues
        - Printer related issues (related to interfaces with our software and not the printer itself)
        - Security issues
        - Performance issues not impacting critical processes
        - Usability issues
        - Workstation connectivity issues (Workstation specific)

Priority 3 - Low

- Report formatting issues
- Training questions, how to, or implementing new processes
- Aesthetic issues
- Issues with workarounds for large majority of accounts
- Recommendations for enhancements on system changes
- Questions on documentation

o Response time and the anticipated process to address specific FIS related regulatory requirements that are mandated for all Ontario utilities. NOTE: BPI understands that without context, this requirement will be hard to address. The intent isn't to be specific about a particular requirements such as OESP, but rather to better understand the process that is used by the proponent in accommodating these requirements and whether the proponent is willing (for BPI or for other current customers) to implement milestones and remedies that are specific to a regulatory change at the time that the change is mandated.

4.0 Third Party Licence Requirements

RFP 15-17 Reference

BPI's RFP 15-17 did request that proponents provide information regarding the licensing requirements in section **3.3 FIS Hardware Specification.** BPI has updated the estimated number of users of each module to assist the proponent in providing accurate pricing information pertaining to the modules and the associated licenses. Sixty-five is the approximate total number of employees of BPI and the affiliate companies, and the reason that 65 users are thought to be required for HR and Payroll, in the event that the vendor's system allows employees to enter their own payroll information. The proponent should clearly identify how third party licences are determined and how they are impacted by the number of users.

BAFO Requirement

As it is difficult for BPI to determine with certainty the number of users that will ultimately use the various modules as that will depend on the final business processes selected, the BAFO should reflect on the pricing sheet the actual cost of third party licences based on the specified number of users. In addition, the BAFO should clearly describe the methodology the proponent will use to update the final pricing for the third party licencing fees for each module should BPI increase or decrease the specified number of users.

5.0 Process and Tentative Milestones

Milestone	Description	Date
BAFO Evaluation	BPI will evaluate the BAFO submissions.	December 7, 2015
Management Recommendation / Negotiations	Discussions with the preferred proponent to commence.	Dec. 9 - Jan. 8, 2016
Board Approval in Principle	The Board ratifies the selection of the preferred proponent in principle	Dec. 16, 2015
Final Contract Development	BPI and the preferred proponent enter into a tentative contract (pending the Board's approval) that reflects the BAFO terms and conditions subject to amendments resulting from the discovery phase of the implementation process)	Jan. 18, 2016
Final Contract Review	The proposed agreements are given a final legal review	March 15, 2016
Board Final Contract Approval	The Board of Directors provides final approval	March 31, 2016

6.0 Desired Project Implementation Milestones

Milestone	Description	Date
Discovery Sessions	Proponent completes discovery sessions with BPI to validate BAFO terms and conditions for both parties (Time period reflects the need that financial SMEs will have limited availability until after the close of the 2015 fiscal year)	Jan 15, 2016 to Mar 7, 2016
Implementation Kick Off	The Project proceeds to the implementation phase	Apr 1, 2016
Implementation Completion	BPI is looking to have the proposed solution along with all modules fully implemented.	Dec. 31, 2016

BAFO - Pricing Form (Schedule of Prices)

ADDITIONAL UNIT PRICES FOR EXTRA WORK

No payment will be made to the contractor unless the extra work is ordered by Brantford Power Incorporated.

Additional Resources	Hourly Rate
Solutions Architect	$ -
Principal Consultant	$ -
Program Manager	$ -
Application Consultant	$ -
Principal Software Engineer	$ -
Principal Data Analyst	$ -
Senior Software Engineer	$ -
Systems Engineer	$ -
Software Engineer	$ -

Additional Incidental Costs	Price
Travel Time and Mileage Costs (per diem)	$ -
System Training (per diem)	

Attachment 4-Staff-40-COS Presentation for Board

Brantford Power Inc.

2017 Cost of Service

Rate Application

BRANTFORD power
Your delivery company

2017 Cost of Service

Rate Application

APPLICATION CONTENT OVERVIEW

Renewed Regulatory Framework
2017 CoS Application Content

2017 Cost of Service Application	
Exhibit	Purpose
1	Administration
2	Rate Base
3	Operating Revenue
4	Operating Costs
5	Cost of Capital and Capital Structure
6	Calculation of Revenue Sufficiency or Deficiency
7	Cost Allocation
8	Rate Design
9	Deferral & Variance Accounts

Distribution System Plan

Customer Engagement Findings

New for 2017

2017 Key Issues – Consolidated Facility

RATE BASE	REVENUE REQUIREMENT
• Full capital cost excluding 5 acre surplus land • Occupied and used and useful in 2016 • No half year rule in 2017	• Full depreciation and return • Exclude operating costs attributable to excess space • Include offset revenues from existing tenant and rent from affiliates

2017 Key Issues – System Integration

RATE BASE	REVENUE REQUIREMENT
• Capitalize software license costs • Capitalize direct implementation costs • FIS in 2016 – no half year rule • CIS & OMS in 2017 – half year rule	• Full depreciation and return • HW hosting costs, SW Mtce costs, internal costs, 3rd party costs + non capitalizable costs • Proposed 5 year cost average applied to 2017 to smooth impacts

2017 Key Issues – Cost Drivers

Item	$ Amount	Reference
2013 Board Approved OM&A (exlcuding LEAP)	8,854,025	
System Integration Projects	495,143	
Increase in Salary, wages and benefits	1,119,894	
Employee services provided to affiliates - Wages reallocated to Non-Utility Expenses	(275,856)	
Organizational Improvements/Strategic Initiatives	272,000	
Restructuring of Service Level Agreement	(186,758)	
Direct Labour Project Mix / Payroll Burden Allocation	(176,131)	
Other Charges (net)	385,627	
2017 Test Year OM&A	**10,487,944**	

2017 Key Issues – Other

RATE BASE

- IRRP Hydro One upgrades not in service until 2018 – Notice of ICM
- DSP Investments for 2017 incorporated
- Lower working capital allowance – OEB directive

Other

- Variance account for 2017 Cap and Trade Impacts
- Request to recover outstanding issue from 2013 Cost of Service error
- SLA extended with the exception of building and FIS related costs.
- 2016 Federal Budget – CEC Changes

RATE BASE HIGHLIGHTS
(in $1,000)

RATE BASE	2013	2017	Net Change	% Change
Avg. Net Fixed Assets	63,627	78,965	15,338	24.1%
Allowance for Working Capital	12,111	9,109	(3,002)	(24.8%)
Rate Base	**75,738**	**88,074**	**12,336**	**16.2%**

WORKING CAPITAL ALLOWANCE	2013	2017	Net Change	% Change
Controllable expenses	8,790	10,362	1,572	17.9%
Cost of Power	96,525	111,092	14,567	15.1%
Working Capital Base	105,315	121,454	16,139	15.3%
Working Capital Allowance (2013-11.5% - 2017 - 7.5%)	**12,111**	**9,109**	**(3,002)**	**(24.8%)**

BRANTFORD power Your delivery company

REVENUE REQUIREMENT HIGHLIGHTS (in $1,000)

REVENUE REQUIREMENT	2013	2017	Net Change	% Change
OM&A Expenses + Property Taxes	8,866	10,496	1,630	18.4%
Depreciation	2,901	3,697	796	27.4%
Income Taxes (Grossed Up)	590	693	103	17.5%
Deemed interest expense	1,970	2,097	127	6.5%
Return on Deemed Equity	2,721	3,238	517	19.0%
Service Revenue Requirement	**17,047**	**20,220**	**3,173**	**18.6%**
Revenue Offsets	1,220	1,335	115	9.4%
Revenue Requirement	**15,827**	**18,885**	**3,058**	**19.3%**

REVENUE DEFICIENCY
(in $1,000)

Service Revenue Requirement	2013 Approved (A)	2017 Revenue at Existing Rates Allocated in Proportion to 2013 Approved (B)	2017 Proposed (C)	Revenue Deficiency (D)= (C)-(B)
OM&A including property taxes	8,866,025	9,080,209	10,495,506	1,415,297
Depreciation	2,900,650	2,970,724	3,696,567	725,844
Return on Rate Base	4,689,981	4,803,281	5,334,383	531,102
PILs	589,927	604,178	693,105	88,926
Total	**17,046,583**	**17,458,392**	**20,219,561**	**2,761,169**
Rate Base	**75,737,921**		**88,074,031**	**12,336,110.14**

2017 Cost of Service

Rate Application

CUSTOMER ENGAGEMENT FINDINGS

CUSTOMER ENGAGEMENT - SATISFACTION

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

CUSTOMER ENGAGEMENT - RATES

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**

2017 Cost of Service

Rate Application

DISTRIBUTION SYSTEM PLAN SUMMARY

BRANTFORD power Your delivery company

DUSTRIBUTION SYSTEM PLAN SUMMARY

	Historical					Forecast				
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
	Actual	Actual	Actual	Actual	Budget	Forecast	Forecast	Forecast	Forecast	Forecast
System Access	1,503,450	1,452,693	1,098,678	1,282,158	1,125,683	1,711,017	2,108,207	3,525,912	2,341,333	1,269,199
System Renewal	1,292,552	447,280	528,003	744,529	704,415	607,313	525,206	843,801	696,548	545,989
System Service	713,987	553,194	837,000	1,531,276	403,945	425,798	592,642	159,840	229,640	340,160
General Plant	434,228	454,691	324,327	553,348	16,134,256	1,407,853	4,252,536	808,100	235,400	415,800
Total	**3,944,217**	**2,907,858**	**2,788,008**	**4,111,311**	**18,368,299**	**4,151,981**	**7,478,591**	**5,337,653**	**3,502,921**	**2,571,148**

2017 Cost of Service

Rate Application

RATE IMPACT SUMMARY

RATE IMPACT SUMMARY

Class	kWh	kW	# of connections	2016 Bill Amount	2017 Bill Amount	Difference	Total Bill Impact %	Distribution Bill Impact %
Residential	750			$ 134.14	$ 136.06	$ 1.92	1.43%	6.57%
Residential (10th percentile)	277			$ 61.45	$ 66.30	$ 4.85	7.89%	21.35%
Residential (non-RPP)	800			$ 176.17	$ 177.55	$ 1.38	0.78%	4.29%
General Service Less than 50 kW	2000			$ 333.68	$ 336.37	$ 2.70	0.81%	4.69%
General Service Less than 50 kW	3000			$ 480.85	$ 482.33	$ 1.48	0.31%	2.36%
General Service 50 to 4,999 kW	195000	500		$ 26,629.97	$ 26,362.21	$ (267.76)	-1.01%	-8.28%
Street Light	325	1	1	$ 46.89	$ 49.76	$ 2.87	6.11%	41.01%
Sentinel	325	1	1	$ 72.88	$ 76.61	$ 3.73	5.12%	13.16%
Unmetered Scattered Load	275			$ 56.44	$ 57.58	$ 1.14	2.03%	11.27%
Embedded Distributor	1500000	4000		$187,067.21	$189,452.08	$ 2,384.88	1.27%	30.52%

2017 Cost of Service

Rate Application

APPROVAL PROCESS

Approval Process

Attachment 4-Staff-56: OPEB

Brantford Power

Fiscal Year	January 1, 2015 to December 31, 2015	January 1, 2014 to December 31, 2014	January 1, 2013 to December 31, 2013
Starting values			
Accrued benefits	1,366,883	1,227,742	1,724,162
Adjustment due to January 1 valuation	(161,822)	-	-
Adjusted Accrued benefits	1,205,061	1,227,742	1,724,162
Assumed discount rate on liabilities at Beginning of Period ("BOP")	3.50%	4.25%	3.50%
Assumed discount rate on liabilities at End of Period ("EOP")	3.75%	3.50%	4.25%
Accrual for service (normal cost)	71,129	55,996	60,762
Actual benefit payments	52,222	70,000	109,752
Expected benefit payments	52,222	70,000	109,752
Average Remaining Service Period to retirement	15.0	14.0	14.0
Average Remaining Service Period to full eligibility	12.0	11.0	11.0
Exhibit I - Interest on accrued benefits			
Opening balance	1,205,061	1,227,742	1,724,162
Accrual for service	71,129	55,996	60,762
Benefit payments (mid-year)	(26,111)	(35,000)	(54,876)
Total	1,250,079	1,248,738	1,730,048
Interest	43,753	53,071	60,552
Exhibit II - Experience gains/ losses - accrued benefits			
Opening balance	1,205,061	1,227,742	1,724,162
Accrual for service	71,129	55,996	60,762
Interest on accrued benefits	43,753	53,071	60,552
Prior service costs	-	-	-
Benefit payments	(52,222)	(70,000)	(109,752)
Expected value at EOP	1,267,721	1,266,809	1,735,724
Actual value at EOP	1,236,004	1,366,883	1,227,742
Experience gain (loss)	31,717	(100,074)	507,982
Exhibit III - Unamortized experience			
Experience gain/(loss) at BOP	732,462	887,133	395,054
Adjustment due to January 1 valuation	161,822	-	-
10% Corridor	120,506	122,774	172,416
Total amount to be amortized	773,778	764,359	222,638
Amortization amount	(51,585)	(54,597)	(15,903)
Changes during year	31,717	(100,074)	507,982
Experience gain/(loss) at EOP	874,416	732,462	887,133
Exhibit IV - Post-retirement benefits cost recognized			
Accrual for services (total)	71,129	55,996	60,762
Interest on accrued benefits	43,753	53,071	60,552
Actuarial (gains) losses during year	(31,717)	100,074	(507,982)
Plan amendments during year	-	-	-
Net Benefit Cost Incurred	83,165	209,141	(386,668)
Adjustment for experience (gains)/losses	(19,868)	(154,671)	492,079
Adjustment for prior service costs	-	-	-
Net expense	63,297	54,470	105,411
Exhibit V - Calculation of accrual			
Accrued benefit liability at BOP	2,099,345	2,114,875	2,119,216
Expense (Income) for the year	63,297	54,470	105,411
Funding contributions (total)	(52,222)	(70,000)	(109,752)
Accrued benefit liability at EOP	2,110,420	2,099,345	2,114,875
Exhibit VI - Reconciliation			
Accrued benefit obligation at EOP	1,236,004	1,366,883	1,227,742
Less unamotized:			
Experience (gains)/losses	(874,416)	(732,462)	(887,133)
Prior service costs	-	-	-
Accrued benefit liability at EOP	2,110,420	2,099,345	2,114,875
Exhibit VI - Sensitivity in Health and Dental Care Trends			
Trend 1% Higher			
Change in Service and Interest Cost	15,986	15,311	16,124
Change in Accrued benefit obligation	114,441	143,963	113,023
Trend 1% Lower			
Change in Service and Interest Cost	(13,252)	(12,731)	(13,307)
Change in Accrued benefit obligation	(98,053)	(120,867)	(96,273)

Attachment 5-SEC-25: Promissory Note

PROMISSORY NOTE

Due: February 1, 2016

FOR VALUE RECEIVED, Brantford Power Inc. ("the Corporation") hereby promises to pay to or to the order of The Corporation of the City of Brantford (the "City") the Principal Sum of TWENTY-FOUR MILLION, ONE HUNDRED AND EIGHTY-NINE THOUSAND, ONE HUNDRED AND SIXTY-EIGHT DOLLARS ($24, 189,168) (The "Principal Sum") with interest at the rate specifed herein on February 1, 2016 (the "Maturity Date"). Interest on the Principal Sum shall accrue from the first day of February, 2011 and be payable at a rate per annum equal to the rate of five and eighty-seven one hundredths percent (5.87%). Interest at the aforesaid rate shall be payable annually to the City on the 30th day after the end of the Corporation's fiscal year.

At the option of the City and with six (6) months prior written notice by the City to the Corporation, this Promissory Note may be extended for successive periods (an "Extension Period") of five (5) years at a rate of interest equal to the prime rate of the Royal Bank of Canada (charged to its customers for commercial loans) plus one and one half percent (1.5%) or such other rate of interest as the City and the Corporation may agree upon (the "Extension Period Rate"). Interest at the Extension Period Rate shall be payable annually to the City on the 30th day after the end of the Corporation's fiscal year.

The obligation of the Corporation to pay the Principal Sum and all interest on this Promissory Note is subordinated and postponed to the obligations of the Corporation from time to time to any other financial institution or lender.

This Promissory Note may, at the option of the City, be converted, as to some or all of the Principal Sum outstanding, into common shares of the Corporation at a conversion ratio of $100 per share. The foregoing conversion right may be exercised by the City at any time on ninety (90) days prior written notice to the Corporation.

The terms of the Promissory Note are subject to the adjustment provisions of the Transfer By-law passed by the City on October 23, 2000 as By-law Number 156-2000.

This Promissory Note is not assignable by the City without the consent of the Corporation.

DATED this   day of January 2011.

BRANTFORD POWER INC.

Per: Heather Wyatt
Name: Heather Wyatt
Title: Secretary

Per: Tim Curtis
Name: Tim Curtis
Title: Chair

Attachment 4-VECC-44: OILC Rate

Lending Rates: Local Distribution Companies

Indicative Lending Rates as of 17/02/2016

Term	Construction	Serial	Amortizer
1 Month	1.62%	-	-
5 Year	-	1.83%	1.84%
10 Year	-	2.49%	2.52%
15 Year	-	2.97%	3.02%
20 Year	-	3.27%	3.35%
25 Year	-	3.47%	3.56%
30 Year	-	3.58%	3.68%

About our Lending Rates

Our online lending rates are updated frequently as we track the movement of our cost of borrowing in the capital markets.

Debentures - rates on debentures are fixed for the entire life of the loan once the debenture is purchased by Infrastructure Ontario.

Construction Loans - for construction loans, rates float throughout the term of the loan until they are replaced by a debenture. Construction loan requests over $75 million are subject to funding availability and interest rates may vary from those posted.

**These interest rates are the all-in cost for loans of the term and type selected

Ontario
Infrastructure Ontario

Attachment 9-Staff-68: DVA Continuity Schedule

(filed as live excel)

Attachment 9-VECC-47A: Issue 9 from Settlement

9.0 DEFERRAL AND VARIANCE ACCOUNTS (Exhibit 9)

9.1 Are the account balances, cost allocation methodology and disposition plan appropriate?

Status: **Complete Settlement**

Supporting Parties: BPI, Energy Probe, SEC, VECC

Evidence: Application: Exhibit 9 Tab 2 Schedules 1, 3, 4, 5

Interrogatories: 9-Staff-31, 9-Energy Probe-31

For the purposes of settlement, the Parties agree the account balances, cost allocation methodology and disposition periods for the deferral and variance accounts as presented in the evidence cited above, adjusted for the matters discussed below, are appropriate.

An updated version of BPI's EDDVAR Continuity Schedule as agreed upon by the Parties is attached as Attachment N.

Smart Meter Disposition Rider

Status: **Complete Settlement**

Supporting Parties: BPI, Energy Probe, SEC, VECC

Evidence: Application: Exhibit 9, Tab 3, Schedule 1

Interrogatories: 4-EP-22; 4-EP-38s; 4-EP-39s; 4-EP-43s; 4-Staff-14; 4-Staff-44s; 9-Staff-35; 9-Staff-36; 9-Staff-37; 9-Staff-39; and 9-Staff-48s.

Attachment 9-VECC-47B: 2013 Interrogatory Response

9.0 Staff-31

Ref: Exhibit 9, Tab 2, Schedule 1, Page 10-11, Account 1582

BPI is seeking recovery of the December 31, 2012 balance in Account 1582 in the amount of $353,252.

BPI states that totals for 2002-2004 would have been included in the 2006 EDR recovered amount in 1580. However, since BPI reallocated these amounts from Account 1580 to Account 1582, BPI reduced future recoveries of Account 1580 balances.

The Board ordered final disposition of all of the BPI deferral and variance account balances in its 2006 EDR, and Accounts 1580 and 1582 were disposed of on a final basis.

a) Did BPI obtain Board approval to reallocate balances from the accounts that were disposed of on final basis?

Response: BPI did not obtain Board approval to reallocate the balances from Account 1580 to Account 1582. However, this matter was identified to Board staff during its audit conducted in 2007. A copy of correspondence received from Board staff dated August 27, 2007 setting out the results of the audit review of regulatory balances is attached as Appendix # to this document. The reallocation of balances is discussed at item 2.3b on page 8.

b) Please confirm that the amount reallocated from Account 1580 to 1582 that was already disposed of on final basis was a debit of $211,246.13 (total of the amounts for the years 2002, 2003, and 2004, shown on page 11)

Response: BPI confirms that the amount reallocated from Account 1580 to 1582 that was already disposed of on final basis was a debit of $211,246.13 (total of the amounts for the years 2002, 2003, and 2004.

c) Please provide alternative rate rider calculations after removing the $211,246.13 and all related carrying charges from Account 1582.

Response: While BPI is of the view that the amounts booked to Account 1582 should be passed through to the ratepayers, BPI has provided the requested alternative rate rider calculations after removing the $211,246.13 and $73,156.05 carrying charges from Account 1582 in the tables below.

Table 9.11: 2013 Deferral and variance Account Rate Rider by Class

Customer Class	Group 1 Variance Accounts	Group 2 Variance Accounts	Total of Accounts 1562 & 1592	Total Variance Accounts	Billing Determinnents Projected 2013 KWh	Projected 2013 KW	Recovery Period (Years)	Rate Rider
Residential	$ (1,494,173)	$ 336,334	$ (20,601)	(1,178,440)	280,913,502	-	1	$ (0.0042)
GS< 50 kW	$ (518,788)	$ 116,778	$ (7,153)	(409,163)	97,535,297	-	1	$ (0.0042)
GS> 50 kW	$ (2,829,579)	$ 636,931	$ (39,014)	(2,231,662)	531,977,718	1,354,270	1	$ (1.6479)
Unmetered Scattered Load	$ (7,738)	$ 1,742	$ (107)	(6,103)	1,454,727	-	1	$ (0.0042)
Sentinel Lighting	$ (2,359)	$ 531	$ (33)	(1,860)	443,490	1,356	1	$ (1.3718)
Street Lighting	$ (40,174)	$ 9,043	$ (553.9)	(31,685)	7,553,004	23,455	1	$ (1.3509)
Total	$ (4,892,811)	$ 1,101,359		(3,858,913)	919,877,738	1,379,081		

Table 9.12: 2013 Non-RPP Global Adjustment Rate Rider by Class

Customer Class	Total Variance Accounts	Projected 2013 Non-RPP KWh	Projected 2013 Non-RPP KW	Recovery Period (Years)	Rate Rider
Residential	$ 65,816	36,518,755	-	1	$ 0.0018
GS< 50 kW	$ 17,578	9,753,530	-	1	$ 0.0018
GS> 50 kW	$ 709,485	393,663,512	1,002,159	1	$ 0.7080
Unmetered Scattered Load	$ 2,622	1,454,727	-	1	$ 0.0018
Sentinel Lighting	$ 799	443,490	1,356	1	$ 0.5894
Street Lighting	$ 13,612	7,553,004	23,455	1	$ 0.5804
Total	$ 809,913	449,387,018	1,026,971		