# EXHIBIT A: RATE PLAN

## A-CCC-1

On March 12, 2015, the Board released its Decision regarding the Hydro One Inc. rate application for a five-year custom plan (EB-2014-0247). In that Decision the Board set out a number of reasons why Hydro One's application is insufficient as a Custom IR application under the RRFE. In light of the conclusions reached by the Board in that case, please explain how PowerStream's application is compliant with the RRFE.

**RESPONSE:**

The PowerStream application is consistent with the intent of the RRFE with respect to Custom IR applications. The RRFE Report states *"This Report provides the general policy direction for this rate-setting method, but the Board expects that the specifics of how the costs approved by the Board will be recovered through rates over the term will be determined in individual rate applications. This rate-setting method is intended to be customized to fit the specific applicant's circumstances. Consequently, the exact nature of the rate order that will result may vary from distributor to distributor."* (RRFE Report pg. 18).

The RRFE Report also states *"The Board does not intend to publish filing requirements for the Custom IR method (other than the Consolidated Capital Plan Filing Requirements) at this time, although much of the material in Cost of Service Filing Requirements will be relevant for Custom IR filers. Consistent with the conclusions set out in this Report in relation to the Custom IR method, the onus will be on the applicant to specify and substantiate its preferred approach to multi-year rate-setting. After the Board has gained some experience with these types of applications it may publish filing requirements for Custom IR applicants"* (RRFE Report pg. 70).

The Custom IR features discussed in the Hydro One Distribution (EB-2013-0416) decision relate to the RRFE central policy objectives of measuring performance and providing incentives for continuous improvement. The Board's findings in the Hydro One decision indicate the need for a utility to focus on a number of areas as described below. Beneath each focus area is a description of how PowerStream's application addresses these Custom IR requirements:

*1.* Consistency with outcomes based regulation
   - PowerStream followed a top down and bottom up approach to budgeting, rather than simply extrapolating prior resource based spending patterns. This included use of asset management practices and risk based

prioritization of capital spending. Spending levels have been established with a focus on meeting all outcome based OEB Scorecard targets.

*2.* Externally Imposed Incentives
- OM&A is set at a level lower than "status quo" costs to drive PowerStream to seek and find further productivity savings or risk earning less than the regulated return. These savings, whether they are achieved or not, are passed on to customers through lower proposed OM&A levels during the Custom IR term. PowerStream has provided analysis to support that the embedded productivity savings meet or exceed the Board's expectation embodied in the X factor. (Exhibit F, Tab 1, p3. 3-5)

*3.* Benchmarking evidence
- Comparison to predicted costs based on the Pacific Economics Group econometric model used by the OEB to set stretch factors (Exhibit F, Tab 2, pgs. 1-4)
- Comparisons to other LDC's (Exhibit F, Tab 2, pgs. 5-8)

*4.* Prospects for continuous improvement
- Specific examples of continuous improvement are provided in Exhibit F, Tab 1, pgs. 7-10

*5.* Value to customers
- PowerStream engaged customers in a variety of ways including customer engagement on the Distribution System Plan and has considered customers preferences in formulating its plan;
- Customers are receiving value through the submitted application through the achievement of customer identified priorities such as service reliability and cost. The submitted plan contains investments in assets and operations that will allow for the achievement of appropriate service reliability levels. In addition, only necessary costs are included in the plan and customers have been given a commitment to the achievement of productivity savings during the Custom IR term.

PowerStream's application is different than Hydro One's in that it has specifically addressed the above RRFE requirements.
The RRFE Report states *"The Board expects that a distributor that applies under this method will file robust evidence of its cost and revenue forecasts over a five year horizon, as well as detailed infrastructure investment plans over that same time frame. In addition, the Board expects a distributor's application under Custom IR to demonstrate its ability to manage within the rates set, given that actual costs and revenues will vary from forecast. (*RRFE Report, pg. 19)

PowerStream application is consistent with the RRFE requirements for a Custom IR application as it meets the requirements contained in the above mentioned sections of the RRFE Report, and, in addition to the features mentioned above, includes:

- A 5 year plan duration supported by capital and OM&A budgets with a complete budgeting process, review and approval;
- A comprehensive Distribution System Plan that meets all the requirements of Chapter 5 of the Board filing guidelines;
- A commitment to the plan term with no expectation of seeking early termination;
- Expected productivity gains that exceed those of the Board's IRM methodology for the rate period that are reflected in lower rates through lower forecast OM&A and Capital levels than otherwise would have been the case;
- The risk of not achieving the embedded productivity savings is borne entirely by PowerStream; and
- Benchmarking of results consistent with the PEG report and peer-to-peer benchmarking information contained in the OEB Yearbook.

**A-CCC-2**

**REF: Ex. A/T1/ /p. 1**

The evidence sets out a truncated list of what the RRFE requires and how PowerStream has addressed those requirements. Please address the extent to which PowerStream's application has addressed the complete list of RRFE requirements.

**RESPONSE:**

PowerStream believes that it has addressed the complete list of RRFE requirements. Please also see the response to A-CCC.1.

**A-CCC-3**

**REF: Ex. A/T1/ /p. 1**

Please address the extent to which PowerStream's application has addressed the RRFE requirement "outcome measures" as follows:

a) Customer Focus: services are provided in a manner that responds to identified customer preferences;
b) Operational Effectiveness: continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives;
c) Public Policy Responsiveness: utilities deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board); and
d) Financial Performance: financial viability is maintained; and savings from operational effectiveness are sustainable.

As part of the RRFE the Board requires that a Scorecard will be used to monitor individual distributor performance and to compare performance across the distribution sector. Please provide the Board's scorecard (and associated annual targets) that PowerStream intends to report on during the term of the plan. Is PowerStream proposing additional metrics to measure its performance during the plan in addition to those set out in the Board's Scorecard? If so, please identify those metrics and the associated targets.

**RESPONSE:**

PowerStream proposes to use the Board's scorecard as its outcome measures.

PowerStream also proposes to report on capital spending as required by the RRFE.

The current Board scorecard is attached as A-CCC-3 Appendix A.

**A-CCC-4**

**REF: Ex. A/T1**

With respect to capital the RRFE states specifically that once rates have been approved the Board will monitor capital spending against that approved plan by requiring distributors to report capital spending against the approved plan by requiring distributors to report annually on actual amounts spent. If spending is significantly different from the level reflected in a distributor's plan the Board will investigate the matter and could terminate the rate-setting method. Please set out specifically how PowerStream will comply with this requirement. What level of detail does PowerStream intend to report on?

**RESPONSE:**

PowerStream proposes to report annually on its actual capital spending compared to that contained in the approved Custom IR rate plan. This would be submitted at the same time as the annual RRR reporting.

PowerStream would provide the following level of detail:

- Capital spending in the same detail as our Rate Proposal Exhibit G, Tab 2, Table 3.
- Capital additions in the same detail as Chapter 2 Filing Guidelines Appendix 2-BA.

**A-CCC-5**

Please explain how PowerStream has incorporated "explicit, externally imposed improvement incentives" into its rate proposal.

**RESPONSE:**

As discussed in Exhibit F, Tab 1, PowerStream has interpreted "explicit, externally imposed improvement incentives" as being the Board's productivity or X factor in the IRM price cap formula of IPI-X.

In this same section, PowerStream has undertaken analysis to demonstrate that its forecasted capital and OM&A spending incorporates productivity savings equal to or greater than the "explicit, externally imposed improvement incentives" under IRM.

**A-CCC-6**

Please explain why PowerStream's application should not be considered a Custom Cost of Service application.

**RESPONSE:**

The RRFE Report states *"This Report provides the general policy direction for this rate-setting method, but the Board expects that the specifics of how the costs approved by the Board will be recovered through rates over the term will be determined in individual rate applications. This rate-setting method is intended to be customized to fit the specific applicant's circumstances. Consequently, the exact nature of the rate order that will result may vary from distributor to distributor."* (RRFE Report pg. 18).

The RRFE Report also states *"The Board does not intend to publish filing requirements for the Custom IR method (other than the Consolidated Capital Plan Filing Requirements) at this time, although much of the material in Cost of Service Filing Requirements will be relevant for Custom IR filers. Consistent with the conclusions set out in this Report in relation to the Custom IR method, the onus will be on the applicant to specify and substantiate its preferred approach to multi-year rate-setting. After the Board has gained some experience with these types of applications it may publish filing requirements for Custom IR applicants"* (RRFE Report pg. 70).

The RRFE Report further states *"The Board expects that a distributor that applies under this method will file robust evidence of its cost and revenue forecasts over a five year horizon, as well as detailed infrastructure investment plans over that same time frame. In addition, the Board expects a distributor's application under Custom IR to demonstrate its ability to manage within the rates set, given that actual costs and revenues will vary from forecast. (*RRFE Report, pg. 19)

To highlight from the above OEB excerpts: the RRFE provides the general policy direction; much of the material in Cost of Service Filing Requirements will be relevant for Custom IR filers; a distributor that applies under this method will file evidence of its cost and revenue forecasts over a five year horizon.

As a full set of filing guidelines have not been developed by the OEB, electricity distributors have been given flexibility in bringing forward their applications as long as they contain or adhere to the RRFE principles and features. PowerStream's application is based on a revenue requirement structure. Not only is this structure not prohibited, it is contemplated as the Board speaks of cost and revenue forecasts and the relevance of cost of service filing guidelines. In fact in the case of Horizon Utilities Custom IR Application which was correspondingly structured, the Board has already accepted the settlement agreement. In any event, PowerStream's Custom IR Application can be thought of as Custom Cost of Service Application or a Custom Revenue Requirement Application but espousing and containing RRFE principles and features making it a Custom IR Application. For these principles and features please see Exhibit A of the Rate Proposal filing and PowerStream's response to A-CCC-1.

**A-CCC-7**

**REF: Ex. A/T1/p. 3**

PowerStream is proposing an annual updating of the revenue requirement and resulting rates for 2017-2020. Please describe the annual process that PowerStream is proposing. Please include proposed timelines and a list of the evidence that PowerStream intends to produce as a part of that process.

**RESPONSE:**

Please see the responses to A-Energy Probe-1.

**A-CCC-8**

**REF: Ex. A/T1/p. 3**

Please explain how internally PowerStream intends to measure its progress with respect to productivity during the term of the plan.

**RESPONSE:**

PowerStream's projected productivity improvements will come from implementing various projects and initiatives throughout the term of the plan. PowerStream's Organizational Effectiveness (OE) department will play a lead role in monitoring and reporting on the planned and projected productivity savings in order to measure its progress during the term of the plan. OE will work with the various business units within PowerStream to ensure the Projects and initiatives with significant productivity improvements have metrics and baselines established prior to implementation.

**A-CCC-9**

**REF: Ex. A/T1/p. 5**

The evidence states that PowerStream may request disposition of certain other deferral and variance accounts (beyond those set out in the EDDVAR Report) where the amounts are significant and the circumstances are appropriate for disposition similar to the Board's current direction on disposing of LRAM variance amounts during IRM. Please provide a list of these other accounts and the current balances. How will PowerStream decide what is "significant"? What are the "circumstances" under which PowerStream would apply for disposition of these accounts?

**RESPONSE:**

PowerStream proposes that a Deferral or Variance account ("DVA") balance greater than ± $10 million would be significant and might be considered for disposition.

PowerStream would be guided by the Board's annual IRM DVA Continuity Schedule as to which other DVA accounts may be considered for disposition.

**A-CCC-10**

**REF: Ex. A/T1/p. 5**

The evidence indicates that PowerStream proposes that some unexpected or unpredictable events might be best addressed through a re-opening of the Custom IR rate plan and in other cases may require termination of the plan. PowerStream has provided examples of events that could trigger a re-opening or termination of the plan. In this context how does PowerStream define "material"? Would a future merger or acquisition trigger a re-opening or termination of the plan? If not, why not?

**RESPONSE:**

For purposes of re-opening or termination of the rate plan, PowerStream defines material as 5% of target net income which would be approximately $2 million for 2016. PowerStream proposes that externally driven events with net costs to PowerStream of this magnitude would allow PowerStream to apply for re-opening or termination of the Custom IR rate plan.

PowerStream does not think that a future merger or acquisition need trigger a re-opening or termination of the plan. The Board Report: Rate-Making Associated with Distributor Consolidation, March 26, 2015 (EB-2014-0138) provides guidance on this situation.

**A-CCC-11**

**REF: Ex. A/T1/p. 5**

Given the fact that PowerStream is spending a significant amount on "storm hardening" throughout the term of the plan, how would costs associated with storm damage be treated during the term of the rate plan? Has PowerStream embedded storm damage costs in it budgets? If so, please identify where these costs are accounted for.

**RESPONSE:**

PowerStream has budgeted for storm damage on the basis of historical data and also considered the proposed "storm hardening" initiatives being carried out. Table A-CCC.11-1 summarizes the Storm damage capital and OM&A budget amounts included in the Rate Proposal.

**Table A-CCC.11-1: Storm Damage Budgeted Costs ($ thousands)**

| | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|
| Capital Budget | $1,000 | $1,006 | $1,006 | $1,010 | $1,010 |
| OM&A Budget | $377 | $385 | $391 | $397 | $403 |

**A-CCC-12**

Please provide copies of any corporate scorecards PowerStream has in place. Please provide results and targets for the past 5 years and targets for the rate plan period.

**RESPONSE:**

Corporate Scorecards from 2010 to 2014, as well as the Balance Scorecard developed for 2015, are included in A-CCC-12-Appendix A.

Scorecards for 2016 to 2020 will be developed in the future.

**A-CCC-13**

In recent cases the Board has approved an earnings sharing mechanism as part of several IRM rate plans (Enbridge, Union Gas, Horizon). Would PowerStream be supportive of incorporating earnings sharing into its plan? If not, why not?

**RESPONSE:**

In its Rate Proposal, PowerStream is sharing benefits as contemplated by the *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach.*

**A-Energy Probe-1**

**REF: Ex. A, Tab 1 & 2**

a) Please provide a list of the adjustments that are being proposed by PowerStream in its annual filings for 2017 through 2020. Please subdivide these adjustments to show those that would apply to rates and those that would apply to pass through items.

b) Please provide a comprehensive list of the things that would not be adjusted throughout the Custom IR plan, but would be determined by the Board as part of this application for the entire term of the Custom IR plan. Please subdivide these adjustments to show those that impact on rates and those that would apply to pass through items.

c) PowerStream refers to the annual adjustment process as providing information for a draft rate order. Does PowerStream envision an application process that includes the filing of evidence, the provision for interrogatories, a settlement conference, and if needed, a hearing? If not, please explain.

**RESPONSE:**

a) PowerStream proposes the following annual adjustments for the 2017 through 2020 rate years.

    1) Annual adjustments affecting the calculation of revenue requirement and distribution rates:
        - Updated Working Capital Allowance resulting from updated cost of power forecasts;
        - Updating of cost of capital and return for changes in Board's parameters and new debt issued;
        - Updating of tax estimate;
        - Potential OM&A adjustment only for significant changes in the rate of inflation beyond a threshold; and
        - Changes in fixed – variable splits as directed by Board policy.

    2) Affecting pass through items:
        - Updating of transmission rates based on the most current wholesale transmission costs available;

- Changes in the smart meter entity charge;
- Updating of low voltage rates based on the most current approved Hydro One sub-transmission rates available; and
- Updating of loss factors.

3) Other items affecting rates:
    - Disposition of group 1 Deferral and Variance accounts (DVA) and other DVA as permitted by the Board under IRM.

b) PowerStream proposes that the following items are set for the custom IR term and would not be included in the annual update process:

- Load forecast and billing determinants (including CDM adjustment);
- Revenue Offsets;
- Capital additions and depreciation expense (see also A-Energy Probe-2);
- Cost allocation; and
- OM&A (except for potential inflation adjustment).

c) PowerStream envisions that the "draft rate order" process will be similar to the 4th generation IRM filing process that follows a cost of service rebasing year, both in terms of timing and scope. Due to the limited adjustments, the scope would be similar to an IRM application with some additional items beyond the IRM model and price cap adjustment.

The proposed adjustments are largely mechanical in nature. However some updated values must be determined and the revenue requirement and rates recalculated. This would require filing of supporting material. Such material would include:
:

- Updated cost of power forecast;
- Updated OEB tax model;
- Updated revenue requirement calculation;
- DVA rate riders if applicable;

The derivation of the updated values and the calculations would be different than calculations under the price cap. In that regard, a written hearing may be warranted for some matters. This of course will need to be determined by the Board at the appropriate time.

**A-Energy Probe-2**

**REF: Ex. A, Tab 2**

The evidence indicates that the base revenue requirement would be updated for a number of annual adjustments. Would there be any update based on the capital expenditures and depreciation expense that were actually incurred each year, as opposed to the forecast? If not, please explain.

**RESPONSE:**

PowerStream has not included capital spending adjustments as part of the annual update process in this rate proposal.

This is based on the following reasons:

- As a practical matter an update to the net fixed assets and related depreciation, PowerStream thinks this is beyond the scope of an annual update as this would require substantial evidence and review.
- Underspending in one year may be offset by higher spending in the next year if a significant project is delayed going into service.
- The Report of the Board: Renewed Regulatory Framework for Electricity Distributors (RRFE) on page 13, Table 1 indicates that the differences between actual and planned capital spending are to be tracked in a deferral and variance account. On page 20 of the RRFE, the Board addresses capital spending:

> *Under Custom IR, planned capital spending is expected to be an important element of the rates distributors will be seeking, and hence will be subjected to thorough reviews by parties to the proceeding. Once rates have been approved, the Board will monitor capital spending against the approved plan by requiring distributors to report annually on actual amounts spent. If actual spending is significantly different from the level reflected in a distributor's plan, the Board will investigate the matter and could, if necessary, terminate the distributor's rate-setting method. A distributor on the Custom IR method will have its rate base adjusted prospectively to reflect actual spend at the end of the term, when it commences a new rate-setting cycle. This is consistent with the Board's existing policies in relation to incremental capital under 3rd Generation IR.*

**A-SEC-1**

Please explain how the proposed plan differs from a 5 year cost of service application.

**RESPONSE:**

Please see response to A-CCC-6

**A-SEC-2**

Please explain how PowerStream believes the proposed plan meets the requirements for a Custom IR application as discussed in the Hydro One Distribution (EB-2013-0416) decision.

**RESPONSE:**

Please see response to A-CCC-1

**A-SEC-3**

Please provide a table showing, for each between 2016-2020:

a. The proposed distribution revenue to be collected under the plan.

b. The distribution revenue PowerStream would expect to receive under 4th Generation IRM using 2016 proposed rates as the base.

**RESPONSE:**

Table A-SEC-3-1 below presents the requested information. For purposes of responding to this request only, PowerStream has assumed for 2017 to 2020 a price cap index (IPI-X) of 1.3%, based on an assumed IPI of 1.6% and a stretch factor of 0.3%.

**Table A-SEC-3-1: Proposed vs. 4th GIRM Revenue, 2016 -2020 ($000)**

| | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|
| Proposed in Plan | $ 191,447 | $ 210,004 | $ 220,687 | $ 231,247 | $ 240,869 |
| Assumed IPI-X | n/a | 1.30% | 1.30% | 1.30% | 1.30% |
| Estimated 4GIRM | $ 191,447 | $ 193,936 | $ 196,457 | $ 199,011 | $ 201,598 |

**A-SEC-4**

**REF: Ex. A-1,p.5-6**

Please explain what specific criteria PowerStream believes is appropriate for the Board to apply to any application to re-open to the plan after approval. What specific approvals with regards to the ability to re-open the plan is PowerStream seeking approval of?

**RESPONSE:**

The Board's off-ramp criterion of ±3% ROE is intended to address under-earnings (or over-earnings) that are in PowerStream's view a result of costs and revenues turning substantially different than forecasts that underpin rates.  For PowerStream to be able to manage within the rates set, which is a Board expectation under Custom IR, the Board's off-ramp criterion is viewed by PowerStream as operable for business as usual situations, not for unexpected or unpredictable and therefore un-forecastable events that may compelled by authorities or by industry developments.

PowerStream has provided in Exhibit A-1 examples of events for re-opening.  If these are not specifically captured by the letter or spirit of the Board's Z-factor policy, they should be thought of as such.  In that regard, the criterion should be the Board's materiality threshold - $ 1 million in the case of PowerStream.

The specific approval PowerStream is seeking is Board consent that that PowerStream will be allowed to put forth an application to revise the rate plan in the specific or similar circumstances articulated in Exhibit A-1, pages 5-6.

**A-SEC-5**

Please complete the Board's Cost of Service Checklist.

**Response:**

PowerStream has attached a completed copy of the Board's Cost of Service Checklist. Please refer to A-SEC-5 Appendix A.

**A -VECC-1**

**REF: Ex. A/T-1/pg. 4**

Pre-amble: PowerStream writes "*As discussed above, inflation and productivity have been built into PowerStream's forecasted costs underpinning rates, so no automatic annual adjustment is proposed*"

In its Decision EB-2013-0416 (Hydro One Networks Inc. distribution rates) the Board wrote: "The OEB expects Custom IR rate setting to include expectations for benchmark productivity and efficiency gains that are external to the company. The OEB does not equate Hydro One's embedded annual savings with productivity and efficiency incentives. Incentive-based or performance-based rates are set to provide companies with strong incentives to continuously seek efficiencies in their businesses."

a) Please explain how the proposal is different than Hydro One's (which the Board rejected as not being in conformance with the RRFE principles).

**RESPONSE:**

a) Please see the response to A-CCC-1.

**A-VECC-2**

**REF: Ex. A/T-1/pg. 4 & E-F/T-1/pg.6/Table 5**

a) Please provide the source of the inflation forecasts shown in Table 5.
b) Does table 5 shown CPI, GDPI or some other inflation measurement?

**RESPONSE:**

a) Please see the response to F-Energy Probe-6.

b) Please see the response to part (a).

**A-VECC-3**

**REF: Ex. A/T-1/pg. 2**

a) At the above reference it states: "*PowerStream has prepared five year capital investment plans in the past but only optimized and prepared detailed capital budgets for two year periods*. " Please explain this statement and what bearing it has on the 2017-2020 capital budgets shown in this proposal.

**RESPONSE:**

a) At the time of PowerStream's 2013 cost of service application, capital projects for the years 2012 and 2013 were subject to the capital budgeting process.

   In 2014, the capital budgeting process was extended to cover a six year period, 2015 to 2020, including entering all the proposed projects into the capital optimization tool. The full capital budgeting process was applied for all years of the Custom IR plan.

**A-VECC-4**

**REF: Ex. A/T-2/pg. 1**

a) It appears that PowerStream proposes to set rates interim at the beginning of each new rate followed some time later by final rates based on adjustments of the annual rate filing. Please confirm this is the correct interpretation. If so, please provide details as to the regulatory process that PowerStream proposes to review these adjustments and the final implementation timing of the rates.

**RESPONSE:**

a) Confirmed. PowerStream proposes that the rates for 2017 to 2020, as determined by the Board at the time of approving 2016 rates, would be interim rates. For 2017 to 2020 rates, an annual update and draft rate order be filed for approval of final rates. Please see the response to A-Energy Probe-1 for further details.

# EXHIBIT B: BILL IMPACTS AND PROPOSED RATES

## B-AMPCO-1

## REF: Ex. B-Tab 1, Page 1 Table 1

a) Please add the revenue requirement information for 2013 to Table 1.

## RESPONSE:

Please refer to the updated Table 1 below that includes 2013 Board-Approved Revenue Requirement.

### Table 1: Changes in Revenue Requirement and Drivers ($ millions)

| | 2013 Board approved | 2016 | % change | 2017 | % change | 2018 | % change | 2019 | % change | 2020 | % change |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Revenue Requirement | $154.22 | $191.50 | | $210.00 | | $220.70 | | $231.30 | | $240.90 | |
| Revenue at "current" rates | | $162.40 | | $191.50 | | $210.00 | | $220.70 | | $231.30 | |
| **Increase in revenue required** | | **$29.00** | **17.90%** | **$18.60** | **9.70%** | **$10.70** | **5.10%** | **$10.60** | **4.80%** | **$9.60** | **4.20%** |
| Drivers: | | | | | | | | | | | |
| **IRM Lag** | | **$20.10** | **69.40%** | **$ -** | **0.00%** | **$ -** | **0.00%** | **$ -** | **0.00%** | **$ -** | **0.00%** |
| **Extraordinary items** | | **$5.40** | **18.40%** | **$10.10** | **54.30%** | **$2.00** | **19.10%** | **$0.80** | **7.70%** | **$0.80** | **8.10%** |
| **Business as usual** | | **$3.50** | **12.10%** | **$8.50** | **45.70%** | **$8.60** | **80.90%** | **$9.80** | **92.30%** | **$8.80** | **91.90%** |
| Total | | $29.00 | 100.00% | $18.60 | 100.00% | $10.70 | 100.00% | $10.60 | 100.00% | $9.60 | 100.00% |

## B-CCC-14

## REF: Ex. B/T1/p. 1

The evidence states that the most significant increase in the revenue requirement is, in 2016, due to capital investments made in 2014 and 2015 as well as an increase in the level of operating costs to the 2015 levels. Please provide a schedule summarizing the major capital investments in 2014 and 2015 that PowerStream is seeking to add to rate base. Please indicate why these should be considered "prudent" investments. Please provide a schedule summarizing the main drivers for increased OM&A during the IRM period.

**RESPONSE:**

Table B-CC-14-1 below provides a summary of the in-service capital investments for 2014 and 2015.

**Table B-CC-14-1: 2014 and 2015 In-Service Additions**

| | 2014 | 2015 |
|---|---|---|
| System Access | $ 29.1 | $ 26.1 |
| System Service | $ 17.9 | $ 17.1 |
| System Renewal | $ 38.3 | $ 40.6 |
| General Plant | $ 10.6 | $ 56.1 |
| **Total** | **$ 95.9** | **$ 139.9** |

Investments for 2014 consist of a large number of smaller projects.

- System Access consists mainly of Road Authority of $12.7 million and New Services of $10.0 million, both of these totals represent the sum of many small projects.

- System Service includes the purchase of land for the new Vaughan transformer station #4 of $4.1 million. Details of this project are included in Appendix A of section 5.4.5 of the Distribution System Plan (Exhibit G, Tab 2).

- System Renewal includes Cable Injection of $10.9 million, Emergency restoration of $8.2 million and overhead rebuild and replacements of $4.8 million representing the totals for many discrete projects. Most of these additions relate to capital spending in PowerStream's 2014 rate application under the Incremental Capital Module (ICM). See Exhibit G, Tab 2b, Table and the attached project summaries Appendices B-CC-14-A to B-CCC-14-E for the ICM investment for details.

- General plant consists mainly of a number of projected related to upgrading of information and communications systems including planned replacement of equipment totaling $4.7 million.

The 2015 capital investments for System Access, System Service and System Renewal are similar to 2014 in terms of the types of capital work and amounts. Cable replacement is higher at $11.7 million. There is also new spending for Storm hardening of $3.5 million.

Much of the capital spending and additions in 2014 and 2015 is related to programs examined and approved in the 2013 Cost of Service application (EB-2012-0161). The capital budgeting and control processes described in the Distribution System Plan for 2015 to 2020 were applied to the 2014 capital spending. These were prudent investments.

Information regarding material investments can be found in Appendix A of section 5.4.5 of the Distribution System Plan (Exhibit G, Tab 2).

The increase in general plant capital additions is due to the replace of the customer information and billing system in 2015 with an in-service date in Q2 at a cost of $45.8 million. See the response to B.CCC-15 for more details regarding this investment.

Below is Table B-CCC-14-2 summarizing the main drivers for increased OM&A during the IRM period:

1
## Table B-CCC-14-2

| Recoverable OM&A Cost Driver Table | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Total OM&A ($000's)** | **2014 Actual** | **2015 Bridge Year** | **2016 Test Year** | **2017 Test Year** | **2018 Test Year** | **2019 Test Year** | **2020 Test Year** | **2014 Actuals to 2015 Bridge Year** | **2016 to 2020 Test Years** |
| **Opening Balance** | **80,849** | **85,454** | **92,558** | **96,216** | **98,112** | **99,920** | **102,195** | **80,849** | **92,558** |
| | | | | | | | | | |
| Compensation | 538 | 2,508 | 1,136 | 267 | 745 | 787 | 901 | 3,046 | 3,837 |
| Asset Management | 1,949 | 579 | 472 | 578 | 364 | 416 | 369 | 2,528 | 2,199 |
| Risk Management | 330 | 757 | 518 | 485 | (36) | 138 | (103) | 1,087 | 1,002 |
| Growth | 59 | 144 | 369 | 140 | 232 | 87 | 106 | 203 | 935 |
| Customer Expectation | 754 | (248) | 58 | 25 | 25 | 25 | 25 | 507 | 158 |
| Compliance | 262 | 185 | 132 | 18 | 18 | 18 | 19 | 447 | 205 |
| Other | 929 | 1,464 | 482 | 15 | 110 | 265 | 139 | 2,394 | 1,011 |
| | | | | | | | | | |
| **Closing Balance-Business as usual** | **85,670** | **90,844** | **95,724** | **97,745** | **99,571** | **101,657** | **103,650** | **91,060** | **101,904** |
| **Year over year ($)** | | **5,173** | **4,881** | **2,021** | **1,826** | **2,086** | **1,993** | | |
| **Year over year (%)** | | **6.0%** | **5.4%** | **2.1%** | **1.9%** | **2.1%** | **2.0%** | | |
| **<u>Extra-ordinary items</u>** | | | | | | | | | |
| Vegetation Management | (1,565) | 403 | 614 | 526 | 531 | 536 | 542 | (1,162) | 2,749 |
| CIS Implementation | 1,349 | 1,310 | (122) | (158) | (182) | 1 | 1 | 2,659 | (460) |
| **Closing Balance-Business with Extra-ordinary items** | **85,454** | **92,558** | **96,216** | **98,112** | **99,920** | **102,195** | **104,193** | **92,558** | **104,193** |
| **Year over year ($)** | | **7,104** | **3,659** | **1,896** | **1,808** | **2,275** | **1,999** | | |
| **Year over year (%)** | | **8.3%** | **4.0%** | **2.0%** | **1.8%** | **2.3%** | **2.0%** | | |

2

**B-CCC-15**

**REF: Ex. B/T1/p. 1**

Please provide the business case for the new customer care and billing system. Please provide a schedule setting the annual expenditures (Historical and Forecast) for the new billing system, capital and OM&A.

**RESPONSE:**

The business case for the new customer care and billing system is attached as B-CCC-15 Appendix A. This is the evidence filed by PowerStream in its Cost of Service application EB-2012-0161 at Exhibit B1, Tab 1, Schedule 5.

Annual capital expenditures and a comparison to the initial budget from EB-2012-0161 are summarized in Table 1.

**Table 1: Annual Capital Expenditures for New Billing System ($000s)**

| | Budget per | Actual | | | | Forecast | | Variance from |
|---|---|---|---|---|---|---|---|---|
| | EB-2012-0161 | 2011 | 2012 | 2013 | 2014 | 2015 | Total | EB-2012-0161 |
| **Expenditure** | | | | | | | | |
| Internal Labour | 4,167 | 20 | 1,143 | 2,055 | 2,584 | 2,060 | 7,862 | 3,695 |
| Hardware | 1,155 | - | 470 | - | - | - | 470 | (685) |
| Software | 3,978 | - | 2,891 | 231 | 125 | 11 | 3,258 | (720) |
| Consulting | 1,680 | 60 | 594 | 977 | 4,345 | 4,223 | 10,198 | 8,518 |
| System Integrator | 20,000 | - | 1,214 | 5,955 | 8,507 | 6,554 | 22,230 | 2,230 |
| Legal | 338 | 143 | 128 | 263 | - | - | 534 | 196 |
| Miscellaneous | 613 | - | 3 | 9 | 17 | 94 | 122 | (491) |
| Capital lease | 564 | - | 180 | 311 | 432 | 277 | 1,199 | 635 |
| Contingency | 2,000 | | | | | - | - | (2,000) |
| Total | **34,495** | **223** | **6,624** | **9,801** | **16,008** | **13,218** | **45,874** | **11,379** |

Total project costs of $45.9 Million are $11.4 million higher than the initial plan primarily due to the original project plan being aggressive and only able to absorb a limited number of change requests and schedule slippages. The project took longer than expected to complete due to challenges and complexities associated with system interfaces and testing. The variances are further explained below.

It should be noted that the current approved capital budget for this project is $45.9 million. The rate proposal contains capital costs of $42.8 million. PowerStream proposes to include this change in the first update.

**Internal Labour ($3,695K above plan):** Costs higher than plan due to additional scope of work and system complexities beyond what was originally anticipated. This complexity resulted in project delays and the associated additional staff resource time increased project costs.

**Consulting ($8,518K above plan):** Costs are higher than plan primarily due to additional system complexities and the associated consulting support required. Consulting included support from Oracle (interface design and testing), InfoTech and Util-Assist (system testing), Kaihen (project management and support) and E&Y (training and review). Consulting costs are also higher due to a $3.0M shift in the scope of work initially within the responsibility of the System Integrator (CGI) to PowerStream. This shift included the transfer of responsibility for certain activities such as report development, Organizational Change Management, Middleware and change requests. In addition, the initial project budget did not include $1.1M of overhead burdens associated with the project.

**Systems Integrator ($2,230K above plan):** Costs are higher than planned primarily due to extension of timeline to handle the additional complexities related to system interfaces, change requests and data conversion and testing activities

The primary reason for a later in-service date than initially planned (Q2 2014 to Q2 2015) is system testing that led to the identification of missing or incomplete requirements resulting in Change Requests to all 20 interfaces. It was not possible to fully identify at the "Discovery" phase of a project all of the issues associated with converting from a 30-year old system

The annual OM&A costs for the new billing system are set out in Table B-CCC-15- 2 below.

**Table B-CCC-15-2: Annual OM&A Expenditures for New Billing System ($000s)**

| Expenditure | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|
| ***Information Services:*** | | | | | | | | | |
| Application Managed Services Fee (AMS) | | | | $2,016 | $2,000 | $2,000 | $2,000 | $2,000 | $2,000 |
| Oracle CC&B Software Maintenance Fee | $577 | $535 | $535 | $530 | $535 | $541 | $546 | $551 | $557 |
| Training | | | | $11 | $15 | | | | |
| Other Software Purchase | | | | $47 | $64 | $66 | $67 | $68 | $69 |
| Additional Consulting | | | | $30 | $40 | $40 | | | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Website Hosting Services | | | | $35 | $47 | $12 | | | |
| | | | | | | | | | |
| ***Customer Service:*** | | | | | | | | | |
| Training | | | $1,350 | $19 | $30 | $7 | | | |
| Outsourced Call Centre | | | | $375 | $200 | $125 | | | |
| Miscellaneous | | | | $124 | $141 | $130 | $130 | $130 | $130 |
| | | | | | | | | | |
| **Total** | **$577** | **$535** | **$1,885** | **$3,187** | **$3,072** | **$2,921** | **$2,743** | **$2,749** | **$2,756** |

**B-CCC-16**

**REF: Ex. B/T1/p. 1**

System hardening has been identified as a significant cost driver for 2016 and 2017. Please provide a detailed explanation of this program and a schedule setting out all capital and OM&A expenditures for each year of the plan term related to this program. In addition, please identify all expenditures related to this program each year prior to 2016.

**RESPONSE:**

A detailed explanation of the Storm Hardening & Rear Lot Conversions program is included in the Consolidated Distribution System Plan, Section 5.4.5, page 19 of 36 as noted below

> *Storm Hardening & Rear Lot Conversion*
> Included in the study report was a series of recommendations. This category covers the capital work that PowerStream must complete to harden (strengthen) the overhead distribution system to withstand the frequency and severity of storms (wind, rain, ice) that have been experienced the last few years and, according to meteorologists, is expected to become more common in the future.
>
> The vast majority of PowerStream's overhead distribution system has been designed and constructed to legacy standards for the typical wind and ice loadings commonly experienced at that time. Over the past 15 years, the increased frequency and severity of extreme weather events has led to improvements to construction standards for all new distribution system construction, however, parts of the existing distribution system needs remedial work to bring it up to the latest standards.
>
> PowerStream has a number of pockets of customers (mainly residential) being supplied by rear lot construction. In accordance with the consultant's report, PowerStream will adopt full conversion for rear lots and recommend completion over 15 years. The projects will be prioritized based on age, asset condition, customer needs and reliability.
>
> PowerStream's proposed rear lot conversion investment expenditures for 2016 to 2020 is based on historical expenditures of similar type construction work. The proposed investments are based on estimated construction costs of approximately $12,400 per customer.

Initiatives included in the Storm Hardening program include:

a) *Grade 1/Composite Poles for Strategic Locations:*
PowerStream will continue development of composite pole standards and consider use of composite poles and Grade 1 construction in future construction of poles with 3 or more circuits or critical poles as defined.

b) *Periodic in-line Anchoring :*
PowerStream will review existing lines and determine additional anchoring needs, both in-line anchors and storm-guying. PowerStream plans to reinforce all poles that carry 4 circuits, 1500 poles in all.

c) *Flood Avoidance:*
Relocate all existing flood sensitive equipment (switches, breakers, relays, etc) located in existing transformer stations to be above grade. PowerStream plans to complete this work over four years.

d) *Rear Lot Remediation*:
Convert to full front lot current standard over 15 years.

PowerStream's proposed investment expenditures for 2016 to 2020 is based on combination of available resources and affordability.

From an OM&A perspective, vegetation management is the main focus for system hardening. This includes such activities as increasing the tree clearance cutback around lines, complete removal of any limbs overhanging lines (referred to as "blue-skying"), removal of hazard trees located close to a power line where failures of the tree could pose a hazard to the line, and implementing vegetation management around secondary wires on customer properties.

The capital and OM&A expenditures for each year of the plan term related to this program are shown below.

| (000's) | **2016** | **2017** | **2018** | **2019** | **2020** |
|---|---|---|---|---|---|
| Capital | $ 7,900 | $ 7,999 | $ 7,499 | $ 6,900 | $ 7,200 |
| OM&A | $ 614 | $ 525 | $ 531 | $ 536 | $ 541 |

There are no expenditures for this program prior to 2016.

**B-CCC-17**

**REF: Ex. B/T1 p. 1**

Please provide the complete business case for the Vaughan Transformer Station

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**RESPONSE:**

Please see New Vaughan TS4 Business Case attached as B-CCC-17 Appendix A.

## B-CCC-18

## (Ex. B/T1/p.p. 3-4)

Please provide the distribution increases (Tables 4 and 6) for residential consumers with consumption levels of 400 kWh and 1000 kWhs/month.

## RESPONSE:

### Table B-CCC.-18-1: Summary of Monthly Bill Impacts for a Typical Customer – Distribution Portion (400 kWh/month)

| Customer Class | Billing Determinant | Consumption per Customer (kWh) | Load per Customer (kW) | Distribution Component 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|
| Residential | York Region | 400 | 0 | 16.0% | 7.7% | 3.6% | 0.6% | 3.1% |
| | Barrie | 400 | 0 | 15.5% | 7.7% | 3.6% | 0.6% | 3.1% |

### Table B-CCC-18-2: Summary of Monthly Bill Impacts for a Typical Customer – Distribution Portion (1,000 kWh/month)

| Customer Class | Billing Determinant | Consumption per Customer (kWh) | Load per Customer (kW) | Distribution Component 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|
| Residential | York Region | 1,000 | 0 | 17.7% | 8.9% | 4.0% | 2.1% | 3.5% |
| | Barrie | 1,000 | 0 | 16.9% | 8.9% | 4.0% | 2.1% | 3.5% |

**B-CCC-19**

**REF: Ex. B/T1**

Is the only difference between the Barrie rate zone and the former York Region rate zone related to the 2014 LRAM? If not, please explain the reason for the different rates.

**RESPONSE:**

Yes, the only difference between York Region and former Barrie rates zones is the Rate Rider for Recovery of Lost Revenue Adjustment Mechanism effective until December 31, 2015. This rate rider is applicable to Residential, GS<50 and GS>50 customers in the former Barrie rate zone only.

**B-CCC-20**

**REF: Ex. B/T1**

Has Horizon considered rate smoothing with respect to its plan? If not, why not? If so, why has rate smoothing been rejected?

**RESPONSE:**

PowerStream considered rate smoothing but did not propose this as the total bill impacts are below the Board's threshold that requires rate mitigation.

**B-Energy Probe-3**

**REF: Ex. B, Tab 1**

a) Tables 1 and 2 show the revenue requirement for the 2016 through 2020 period and these figures appear to the match the base revenue requirement found in the electronic versions of the RRWF provided for each year. Please confirm this is accurate.

b) The revenue at current rates shown in Tables 1 and 2 are different than that show in each of the RRWF provided. Please explain what is shown in the RRWF for each year as distribution revenue? In particular, are the figures shown in the RRWF for each year the forecast of customers, kWh's and kW's at the current 2015 rates? If not, please explain fully what the distribution revenue figures in the RRWF's represent and how they were calculated.

c) Tables 1 and 2 appear to show the distribution revenue each year as being equal to the revenue requirement for the previous year. This implies no change in the forecast number of customers, kWh's and kW's over this five year period. Please explain.

d) Please provide a version of Tables 1 and 2 that reflects the rates derived from the revenue requirement of the previous year applied to the current test year forecast of customers, kWh's and kW's.

e) Similar to part (d) above, please provide live electronic versions of the RRWF for each of 2016 through 2020 where the distribution revenue at current approved rates reflects the same thing as in part (d) above, i.e. rates derived from the revenue requirement from the previous year applied to the current test year forecast of customers, kWh's and kW's.

**RESPONSE:**

a) PowerStream confirms that this is accurate.

b) Table 1 below summarizes 2015-2020 revenue requirements and revenue at current rates as presented in 2016 – 2020 RRWFs and Exhibit B Tables 1 and 2.

**Table B-EP-3-1: Revenue Requirement and Revenue at Current Rates ($000)**

| | | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|
| A | Base Revenue Requirement | $174,290 | $191,447 | $210,004 | $220,687 | $231,247 | $240,869 |
| B | Revenue at Current Rates (RRWF) - all years at 2015 rates | 161,153 | 162,444 | 163,345 | 164,308 | 165,283 | 166,319 |
| C | Base Revenue Requirement (Exh. B, Tables 1-2) - no growth | | 162,444 | 191,447 | 210,004 | 220,687 | 231,247 |
| D | Base Revenue Requirement - at previous year RR rates | | 162,444 | 192,544 | 211,010 | 221,832 | 232,548 |

Revenues at Current Rates, as presented in RRWF, are calculated based on the forecasts of customers, kWhs/kWs at current 2015 rates for each of the year from 2016 through 2020. For the purpose of the presentation of the bill impacts (Exhibit B, Tables 1 & 2), revenue at current rates for each of the year starting 2017 is the previous year base revenue requirement figure.

c) Revenue at current rates for each of the year starting with 2017 is taken as the previous year base revenue requirement figure. It does not take into effect the change in the forecast number of customers, kWhs and kWs. For the purpose of the presentation of the bill impacts breakdown by component (i.e. IRM lag, Extraordinary Items, Business as Usual), PowerStream did not perform additional analysis to account for the growth impact.

d) Revenue at current rates, calculated at the rates derived from the revenue requirement of the previous year applied to the current test year forecast of customers, kWhs and kWs, is presented in Line D of Table B-EP-3-1.

Tables B-EP-3-2 and B-EP-3-3 below are updated to reflect the rates derived from the revenue requirement of the previous year as applied to the current test year forecast of customers, kWhs and kWs.

**Table 2: Changes in Revenue Requirement and Drivers ($ millions)**

| | 2016 | % change | 2017 | % change | 2018 | % change | 2019 | % change | 2020 | % change |
|---|---|---|---|---|---|---|---|---|---|---|
| Revenue Requirement | $191.50 | | $210.00 | | $220.70 | | $231.30 | | $240.90 | |
| Revenue at "current" rates | $162.40 | | $192.54 | | $211.01 | | $221.83 | | $232.55 | |
| **Increase in revenue required** | **$29.10** | **17.92%** | **$17.46** | **9.07%** | **$9.69** | **4.59%** | **$9.47** | **4.27%** | **$8.35** | **3.59%** |
| Drivers: | | | | | | | | | | |
| **IRM Lag** | **$20.21** | **69.45%** | | | | | | | | |
| **Extraordinary items** | **$5.37** | **18.45%** | **$9.49** | **54.34%** | **$1.85** | **19.10%** | **$0.73** | **7.67%** | **$0.68** | **8.13%** |
| **Business as usual** | **$3.52** | **12.10%** | **$7.97** | **45.66%** | **$7.84** | **80.90%** | **$8.74** | **92.33%** | **$7.67** | **91.87%** |
| Total | $29.10 | 100.00% | $17.46 | 100.00% | $9.69 | 100.00% | $9.47 | 100.00% | $8.35 | 100.00% |

**Table 3: Changes in Revenue Requirement – Capital and OM&A ($ millions)**

| | 2016 | % change | 2017 | % change | 2018 | % change | 2019 | % change | 2020 | % change |
|---|---|---|---|---|---|---|---|---|---|---|
| Revenue Requirement | $191.50 | | $210.00 | | $220.70 | | $231.30 | | $240.90 | |
| Revenue at "current" rates | $162.40 | | $192.54 | | $211.01 | | $221.83 | | $232.55 | |
| **Increase in revenue required** | **$29.10** | **17.92%** | **$17.46** | **9.07%** | **$9.69** | **4.59%** | **$9.47** | **4.27%** | **$8.35** | **3.59%** |
| Drivers: | | | | | | | | | | |
| **Capital** | **$20.53** | **70.55%** | **$13.23** | **75.82%** | **$7.14** | **73.67%** | **$6.59** | **69.57%** | **$6.04** | **72.33%** |
| **OM&A** | **$8.57** | **29.45%** | **$4.22** | **24.18%** | **$2.55** | **26.33%** | **$2.88** | **30.43%** | **$2.31** | **27.67%** |
| Total | $29.10 | 100.00% | $17.46 | 100.00% | $9.69 | 100.00% | $9.47 | 100.00% | $8.35 | 100.00% |

e) Live electronic versions of the RRWF for each of 2016 through 2020 where the distribution revenue at current approved rates reflects the same thing as in part (d) above are attached as the electronic Appendices B-Energy Probe-3-1 through B-Energy Probe-3-5.

## EXHIBIT C: BUSINESS PLANNING ABD BUDGETING PROCESS AND ECONOMIC ASSUMPTIONS

**C-AMPCO-2**

**REF: Ex. C**

a) Page 1: PowerStream indicates a 10 year capital plan is developed early in the year. Please provide a copy of PowerStream's latest 10 year capital plan.

**RESPONSE:**

Please see latest version of PowerStream's Corporate 10 Year Plan attached as F-SEC-15 Appendix B.

**C-CCC-21**

**REF: Ex. C/p. 1**

Please provide the budgeting guidelines and instructions sent to staff regarding the development of the budgets for 2016-2020.

**RESPONSE:**

The budget guidelines and instructions are provided to PowerStream Senior Leadership and Management Teams at a budget kick off meeting in May.  Please find the budget guidelines document attached as C-CCC-21 Appendix A.

See F-SEC-7 for similar IR and attachment

**C-CCC-22**

**REF: Ex. C/p. 1**

The evidence states that the Corporate Finance Department coordinates and manages the business planning and budgeting process. Furthermore, it states that targets are set for operating and capital expenditures based on a “top down” approach considering corporate strategy and objectives, business needs and financial impact. Please explain the process undertaken to develop this five-year plan in the context of this budgeting process. Please provide the targets set for operating and capital expenditures based on this top down approach for this five- year period. Please explain, in detail, how the “bottom up” approach to the development of the budgets is undertaken by each of the business units.

**RESPONSE:**

PowerStream has a detailed annual planning process which involves all the business groups in the organization. The planning process begins by reviewing and confirming corporate strategy and objectives. This in turn sets the parameters for the development of a six-year plan. The business planning process begins in late March and results in a six-year Budget/Outlook delivered to PowerStream’s Board of Directors for approval in December. Once the Budget/Outlook is approved, this document serves as the baseline for PowerStream’s operating and capital spending activities. With respect to the 2015-2020 planning period, the first year of the Budget/Outlook is the budget for 2015 reporting purposes and also the “bridge year” for rate filing purposes. Budgets beyond the bridge year (2016-2020) underpin the “test years” for this custom IR application.

Overall budget targets are set for operating and capital expenditures based on a top down approach considering corporate strategy, business needs and financial impact. As a means of ensuring PowerStream manages OM&A costs, the initial top down target for the 2015 budget work activity costs was derived based on a three year historical average of actual costs (2011-2013) indexed by 1% for cost increases. Targets for the years after 2015 used the prior year budget and indexed by 1% for cost increases. The initial OM&A targets prior to the detailed bottom build process are identified in the table below.

| | Budget | Budget | Budget | Budget | Budget | Budget |
|---|---|---|---|---|---|---|

| (in Millions of Dollars) | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|
| OM&A | 93.6 | 95.8 | 98.1 | 100.8 | 103.5 | 106.4 |

The capital budget target is developed in parallel with the OM&A budget and the detailed bottom build is led by the Asset Investment Planning Department. The 10 year capital plan is initially updated early in the year based on the aggregation of detailed project request and reviews of project and work program requirements. The capital portfolio is shared with Finance and capital targets are developed taking into consideration financial impacts. Initial capital targets for annual capital spending prior to the detailed optimization and portfolio setting process are shown in the table below.

| (in Millions of Dollars) | Budget 2015 | Budget 2016 | Budget 2017 | Budget 2018 | Budget 2019 | Budget 2020 |
|---|---|---|---|---|---|---|
| Net Capital Expenditures | 114.9 | 121.4 | 120.1 | 114.0 | 105.0 | 100.0 |

The bottom up OM&A budget is led by Corporate Finance who communicates the targets so the business can develop detailed budgets. Business units consider corporate, divisional and business needs when developing their individual budgets. These factors are evaluated against the historical activity and it is determined whether the historical volume or cost levels are relevant to build the future budget costs. Individual business areas assess changes in costs based on business specific drivers that impact their area. (i.e. new contracts, price escalation factors, changes in business operations). Each operating and maintenance project or program is also reviewed during the detailed budget build process. There are various factors that are considered by the business units during this bottom up process. Some notable factors are Asset Condition Assessment studies, reliability standards, historical failure rates, and environment, health and safety requirements, regulatory and operating standards (i.e. cyclical maintenance requirements). Every effort is made to manage within the target. When cost pressures cannot be managed within targets, these cost drivers, whether internal or external, are assessed by the Budget Working Group in order to determine the criticality of incorporating the cost increase in the budget.

The bottom up build of the Capital Budget is led by Asset Investment Planning. Similar to OM&A, business units assess their capital needs based on business requirements and notable factors as outlined above for OM&A. A robust review of the capital projects is performed utilizing software that helps to determine the value and risks associated with a portfolio of projects. The portfolio results are reviewed by a multi-disciplinary review team as a means of setting the final capital portfolio.

The 2015-2020 Budget/Outlook includes a number of other budget areas that underpin the pro-forma financial statements for the planning period, these include; distribution revenue, other revenue and depreciation expense.

Distribution Revenue was developed based on a detailed load and customer forecast and revenue at current rates. 2016-2020 Distribution revenue is based on revenue requirement needs and the multi-year rebasing criteria. The budget for Other Revenue (which includes specific service charges) is determined based on billing determinants for specific service charges, historical averages or forecast volumes where applicable. The Depreciation budget was determined based on MIFRS depreciation rates and is consistent with the approach approved for setting rates in the previous Cost of Service application for establishing 2013 rates.

**C-CCC-23**

**REF: Ex. C/p. 1**

Please explain how the Budget Working Group balanced the objectives of rate mitigation with prudent spending to meet customer need in the context of this application. How did PowerStream decide what would be acceptable rate increases?

**RESPONSE:**

To enhance the Business Plan and Budget review process, and to help make decisions regarding managing OM&A costs and performance, a Budget Working Group (BWG) was created in 2013. Their mandate is to review OM&A rate drivers such as headcount, OM&A cost pressures and capital requirements in order to prioritize and manage increases based on the corporate strategy, objectives and business needs. This has raised the level of scrutiny regarding OM&A and capital costs and helps to ensure that there are appropriate reasons supporting cost increases. Rate impacts and cost drivers in relation to the rate plan increases were discussed with the BWG in their assessment to move forward with the Custom IR application.

**C-CCC-24**

**REF: Ex. C/p. 2**

Please explain how Corporate Finance developed capital expenditure targets for the years 2015-2020. What were the targets developed for each of those years?

**RESPONSE:**

The capital expenditure targets were set as part of the asset management process, as outlined in the DS Plan, Section 5.3.3, page 18. The figures are arrived at as a balance between capital requests, affordability and rate impacts.

Refer to G-AMPCO-7 for the targets developed for each of those years.

**C-CCC-25**

**REF: Ex. C/p. 2**

The evidence states that the capital budgeting process includes setting value and priority to the individual projects in order to evaluate the best capital portfolio mix. Please explain, in detail, how this is done.

**RESPONSE:**

As noted in the Consolidated Distribution System Plan, Section 5.3.3, page 19 of 38, all projects are valued (and optimized) based upon a Value Function. The Value Function is a weighting of a number of Value Measures. Value Measures include risk mitigation, financial benefits, impacts on Key Performance Indicators (KPI), and cost. The Value Function was configured to reflect how projects contribute to PowerStream's strategic objectives as indicated on Section 5.3.3, page 20. Questions were designed to provide value and scoring for these strategic elements, as noted in Exhibit G, Tab 2, Section 5.2.1, Figure 1.

Specifically, each of the Value Measures is calibrated to the same scale (1 value point approximately equal to $1000). Consequently, within the Value Function, each of the Value Measures (except Project Cost) is weighed with the same value of +1. As Project Cost is a negative contributor to Project Value it is weighted with a cost of -1.

All Value Measures are computed on a monthly or annual basis (e.g. the financial benefits for 2017 can be specified as being different than 2018). The stream of benefits (or costs) is converted to a single value for the Value Measure, by taking the Present Value of the stream, back to the beginning of the current fiscal year. The PV calculation uses the system defined discount rate (set on an annual basis). This value is then used in the optimization process.

**C-CCC-26**

**REF: Ex. C/p. 2**

The evidence states that each year a 10-year capital plan is developed early in the year, based on high-level assumptions of potential project activity and program work. Please provide all of the 10-year plans that have been developed since 2013.

**RESPONSE:**

Please refer to G-SEC-15, Appendix B.

**C-CCC-26**

Please provide PowerStream's policies and/or business strategies regarding future mergers and acquisitions. Does PowerStream intend to pursue mergers or acquisitions during the rate plan period? Have the costs associated with these activities been excluded from the regulated revenue requirement? If not, why not?

**RESPONSE:**

PowerStream has a stated objective to pursue growth opportunities through mergers and acquisitions.

**C-Energy Probe-4**

**REF: Ex. C**

a) How many months of actual data are included in the 2015 bridge year forecast included in the information provided?

b) How does PowerStream adjust its forecasts based on unforeseen events that take place after the process is well underway?

c) What is the timing of approval from the Board of Directors?

d) When did PowerStream get approval from the Board of Directors for the current custom IR proposal?

**RESPONSE:**

a) The entire 2015 bridge year amount is based on forecast. No actual data was available at the time that the rate proposal was prepared.

b) Unforeseen events would generally be managed by substituting projects in order to stay within the budget envelope.

c) Budget approval is at the December Board of Directors Meeting.

d) The Rate Proposal was not explicitly approved by the Board of Directors. The Board approved the underlying operating and capital budgets and Financial Outlook on December 12, 2014. This material was presented to intervenors on December 15, 2014.

# EXHIBIT E: REVENUE REQUIREMENT

## E-Energy Probe-5

## REF: Ex. E, Tab 1

Please provide a version of Table 1 that replaces revenue at current 2015 rates with revenue based on rates that would be determined based on the revenue requirement from the previous year, consistent with Question 3d above**.**

## RESPONSE:

Table 1 summarizes the calculation of Base Revenue Requirement for the years 2015 to

2020, revenue at rates based on the previous year's Base Revenue Requirement applied to the current year forecasted customers and billing determinants and the resulting revenue deficiency consistent with interrogatory B-Energy Probe-3(d).

**Table 1: Revenue Requirement and Revenue Sufficiency / (Deficiency)**

| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|
| Rate Base | $977,718,949 | $1,073,615,242 | $1,153,674,695 | $1,238,500,808 | $1,312,461,667 | $1,384,079,504 |
| Cost of Capital | 5.85% | 6.02% | 6.08% | 6.10% | 6.10% | 6.10% |
| Return on Rate Base | 57,193,566 | 64,667,180 | 70,181,135 | 75,496,552 | 80,005,059 | 84,370,740 |
| OM&A Expenses | 92,557,500 | 96,216,191 | 98,112,314 | 99,919,944 | 102,194,621 | 104,193,445 |
| Amortization Expense | 41,677,590 | 46,903,102 | 50,840,767 | 53,526,966 | 56,385,592 | 59,523,663 |
| PILs | (4,652,035) | (3,748,694) | 3,587,891 | 4,560,308 | 5,600,264 | 5,849,838 |
| **Service Revenue Requirement** | **$186,776,621** | **$204,037,779** | **$222,722,107** | **$233,503,769** | **$244,185,537** | **$253,937,686** |
| LESS: Revenue Offsets | 12,487,117 | 12,590,603 | 12,718,312 | 12,816,681 | 12,938,953 | 13,069,086 |
| **Base Revenue Requirement** | **$174,289,504** | **$191,447,176** | **$210,003,795** | **$220,687,088** | **$231,246,583** | **$240,868,600** |
| Revenue at Current Rates | 161,153,031 | 162,444,354 | 192,544,180 | 211,010,249 | 221,832,259 | 232,548,019 |
| **Revenue Deficiency** | **($13,136,473)** | **($29,002,822)** | **($17,459,615)** | **($9,676,840)** | **($9,414,324)** | **($8,320,581)** |

# EXHIBIT F: PRODUCTIVITY, BENCHMARKING AND CUSTOMER ENGAGEMENT

## F-AMPCO-3

**REF: Ex. F-Tab 2**

a) Benchmarking, Page 2, Table 1 Predicted vs. Actual and Forecasted Costs: For the years 2010 to 2014, please provide Predicted OM&A and Predicted Capital.

b) Page 6: PowerStream's goal is to have rates that are in the lowest quartile. By when?

**RESPONSE:**

a) In its calculations of predicted cost, PowerStream utilized PEG's benchmarking work. The purpose of the benchmarking work is to evaluate the total cost incurred by each distributor. PEG's benchmarking model calculates the Predicted Total Cost and does not provide Predicted OM&A and Predicted Capital costs.

b) The charts in Exhibit F-Tab 2 based on 2014 Board-Approved rates for Residential, General Service under 50 kW and General Service greater than 50 kW demand customers, shows PowerStream's rates are in the lowest quartile. This is also true after the inclusion of additional utilities as shown in the response to F-Energy Probe-10.

**F-CCC-27**

**REF: Ex. F/T1/p. 4**

Please explain, in detail, how PowerStream derived, for each year, the "Estimated Productivity Savings" found in Table 2. Please provide all assumptions.

**RESPONSE:**

Please see the responses to F-CCC.28, F-Energy Probe 6, F-Energy Probe-8, F-SEC-6, and F-VECC-6. In the response to F-SEC-6, the productivity savings from capital in Table 2 have been restated. The following comments are based on Table F-SEC-6-1, the restated Table 2.

The estimated productivity savings for OM&A are shown in Exhibit F, Tab 1, Table 4. The starting point is the 2013 Board Approved OM&A of $83.3 million. This amount is adjusted for inflation, customer growth, and net incremental new costs to arrive at the "Status Quo" OM&A for 2014 of $87.9 million.

The Status Quo OM&A for each of the subsequent years is calculated by taking the previous year's Status Quo OM&A and adjusting it for inflation, customer growth, and net incremental new costs to get the Status Quo OM&A for the year.

The net incremental new costs are derived from the OM&A cost drivers but do not include the compensation, growth or asset management cost drivers as these are captured in the inflation and customer growth adjustment factors above. The net incremental new costs need to be considered and accounted for in isolating the estimated productivity savings from the ongoing activities.

For each year, the Status Quo OM&A is compared to the actual/forecasted OM&A as determined through the OM&A detailed budget process and the difference is the estimated productivity savings from OM&A.

Estimated productivity savings from capital, as restated, have been calculated by taking the reduction in capital cost and determining the impact on revenue requirement. See F-SEC-6 for further details.

**F-CCC-28**

**REF: Ex. F/T1/p. 6**

The evidence sets out "Net Incremental Costs for Changing Requirements" in Table 6. Please provide the following:

a) A detailed explanation as to how the New CIS Incremental Costs were derived;
b) A detailed explanation as to how the Vegetation Management costs were derived;
c) A detailed explanation as to how the Compliance costs were derived;
d) A detailed explanation as to what constitutes “Risk Management” in this context and how the costs were derived; and
e) A detailed explanation as to what constitutes “Customer Expectation” costs how those costs were derived.

**RESPONSE:**

a) The new CIS incremental costs are detailed below.

**Table 1**: New CIS Incremental Costs ($)

| | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2016-2020 Total** |
|---|---|---|---|---|---|---|---|---|
| **Net Incremental New Costs** | **1,349** | **1,310** | **(122)** | **(158)** | **(182)** | **1** | **1** | **(459)** |
| | | | | | | | | |
| Information Services: Application Managed Services | | 2,017 | (17) | | | | | (16) |
| Information Services: Training | | 11 | 3 | (15) | | | | (11) |
| Information Services: Other Software Purchased | | 47 | 17 | 1 | 1 | 1 | 1 | 22 |
| Information Services: Additional Consulting | | 30 | 10 | | (40) | | | (30) |
| Information Services: Website Hosting Services | | 35 | 12 | (35) | (12) | | | (35) |
| | | | | | | | | |
| Customer Service: Training | 1,349 | (1,329) | 10 | (23) | (6) | | | (19) |
| Customer Service: Outsource Call Centre | | 375 | (175) | (75) | (125) | | | (375) |
| Customer Service: Miscellaneous | | 124 | 16 | (11) | | | | 5 |

**A detailed explanation of how new CIS incremental costs were derived is as follows:**

- The 2015 cost increase of $2,000,667, relates to the application management of the new CC&B Customer Information System. PowerStream partnered with CGI to provide a fully managed, end to end solution. This is the main driver for the increase in 2015.
- The other main increase in 2015 relates is $375,000 for outsourced customer service call centre costs which are to handle customer inquiries for overflow calls during peak times.

- The last significant increase in 2015 is for $124,500 for miscellaneous customer service costs that include incremental paper, print, and postage due to the move to larger print stock, in addition to outsourced electronic archiving costs.

The years subsequent to 2015 do not have significant increases and are in fact negative.

b) A detailed explanation of how the vegetation management costs were derived for the period of 2015 to 2020 is as follows:
   - 2015 costs increased by $300,000 over 2014 as an outcome of the 2013 ice storm; there has been an increased focus on rear lot tree trimming and heavily forested areas during this year.
   - 2016 costs increased by $614,000 over 2015 for a several reasons. Firstly there was a new lines supervisor and design tech added during this period which increased OM&A by $94,000, hired to support the increase in the vegetation management program. Secondly additional tree trimming (such as increased clearance cutbacks around lines and complete removal of limbs overhanging lines, collectively referred to as hardening the system) will be performed which increases costs by $500,000 during the period. Lastly there were inflationary increases for contracted work.
   - 2017-2020 costs increased by approximately $500,000 each year as a result of the additional tree trimming mentioned above and contract inflation.

c) Compliance costs are costs incurred by PowerStream to ensure compliance with regulations from third parties. The costs include smart grid related costs and regulatory costs associated with the Rate Proposal. The costs for the period 2015 to 2020 are derived as follows:

- 2015 costs consist of consulting and intervenor costs of $171,000 for the settlement of the Custom IR Rate Proposal and associated Board process.

- 2016 costs consist of a decrease in consulting and intervenor costs of $173,000 on the assumption that there will be a settlement, and an increase of $305,000 related to the Smart Grid program due to a change in regulatory accounting treatment. Specifically, in accordance with OEB Filing Requirements, Smart Grid OM&A costs for years prior to 2016 are recorded in deferral account 1534. From 2016 and onwards Smart Grid OM&A costs are no longer being deferred in account 1534 as per the OEB's guidance from the OEB Filing Requirements, and thus are increasing the OM&A costs in 2016.

- 2017 to 2020 contain inflationary increases on the above discussed categories of costs.

d) Risk Management activities include costs associated with pre-hiring for engineering and apprentice programs to ensure appropriate business continuity and succession planning. Costs include additional headcount for specialized positions to manage risks. Health and Safety accreditation costs are also included associated with BS OHSAS 18001 Occupational Health and Safety Management Systems, contractor support costs and HR Contract Management annual service fees. In addition, included are increased insurance costs for the protection of property, plant and equipment.

- 2015 costs consist of costs associated with pre-hiring for engineering and operations of $170,000 and apprentice programs of $169,000 to ensure skills transfer and operational continuity in preparation of upcoming retirements. There were also head count cost increases of $202,000 for specialized skills such as the Emergency Preparedness Manager, Application Support Analyst and Senior Technical Specialist to support PowerStream's growing portfolio of computer applications and associated equipment.

- As in 2015, 2016 costs also consist of costs associated with pre-hiring for engineering and operations, including apprentice programs of $180,000 to ensure skills transfer and operational continuity in preparation of upcoming retirements. There were also head count cost increases of $286,000 for specialized skills such as the Health and Safety Trainer, Legal Contracts Manager and Strategic Support Manager to further manage risks and seize opportunities related to corporate development.

- 2017 costs consist of costs associated with pre-hiring for engineering and operations, including apprentice programs of $122,000 to ensure skills transfer and operational continuity in preparation of upcoming retirements. There were also head count increases of $359,000 for specialized skills such as the Health and Safety Trainer, Legal Contracts Manager and Strategic Support Manager, including pre-hire IS Security Analyst for preparation of an upcoming retirement.

- 2018 to 2020 costs reflect inflationary increases on the above discussed categories.

e) Customer Expectation activities include consulting costs used to undertake surveys that analyze the engagement of customers. There are also costs included in relation to enhancing the call centre used for major outages.

- 2015 shows a decrease in costs. This from the fact that a customer engagement survey was conducted in 2014, there were no survey's conducted in 2015 and therefore consulting costs decreased.

- 2016 to 2020 costs reflect inflationary increases.

**F-CCC-29**

**REF: Ex. F/T1/p 6**

Please provide the full business case analysis for the underground cable program.

**RESPONSE:**

Refer to PowerStream's Cable Remediation Business Case attached as C-CCC-29 Appendix A.

**F-CCC-30**

**REF: Ex. F/T1/p. 7**

If the CIS system has been replaced prior to the plan period why is the replacement considered a ”productivity initiative” for the period 2016-2020?

**RESPONSE:**

While the CIS system is being replaced and is due to go live in 2015, realization of the productivity savings will only occur after the system has been stabilized and users have adopted and become proficient in their use of the new tool.

In PowerStream’s case we will be transitioning from 30 year old legacy practices and procedures, as such, there will still be work required post go live in order to ensure the business processes mirror the available system functionality, otherwise the potential of the system will not be realized.

**F-CCC-31**

**REF: Ex. F/T1/p. 8**

Please provide the business case analysis for the Work Force Management system.

**RESPONSE:**

Please refer to F-SEC-10 Appendix A.

**F-CCC-32**

**REF: Ex. F/T1/p. 10**

The evidence states that PowerStream has a significant pole replacement program due to the quantity of wood poles in service. Please provide the annual historical costs of this program (2012-2014 and 2015 budget). With the introduction of pole reinforcements, how will the costs of this program change during the term of the plan?

**RESPONSE:**

As detailed in the consolidated DS Plan, Appendix A, Project Investment Summaries, Project Code 100867, the annual historical costs are shown below:

| | Historical | | | Proposed |
|---|---|---|---|---|
| **System Renewal** | **2012** | **2013** | **2014** | **2015** |
| **Overhead Lines - Planned Asset Replacement** | **($)** | **($)** | **($)** | **($)** |
| Pole Replacement Program | 4,111,507 | 5,045,992 | 4,872,277 | 4,645,383 |

It is estimated that PowerStream will use the pole reinforcement method at 30 pole locations per year. For each pole reinforcement location, it is estimated that the cost saving is $7,000-$9,500 for a typical pole (pole reinforcement cost vs. pole replacement cost). The potential cost savings for 30 poles is estimated to be $285,000 per year. This cost saving has been reflected in the pole remediation program from 2015 to 2020.

**F-CCC-33**

**REF: Ex. F/T1/p. 10**

Have the savings associated with the PI Enterprise software been built into the budgets (OM&A and Capital) for the term plan? If so, please identify those savings. If not, why not?

**RESPONSE:**

The PI System has saved PowerStream in equipment failure and costs on a number of occasions, with the largest avoided failure being a TS transformer and the other a 10 MVA MS transformer.

No capital budget reductions have been included because there are no planned power transformer replacements in the capital budget.

The PI System has generally contributed to the flattening of the annual Stations OM&A budget because Station staff are more informed of system abnormalities by PI System automatic alerts (emails), as well as the business unit is more able to plan equipment replacements prior to failure, thus reducing costs. As well, the PI System allows maintenance scheduling to shift from time based to condition based triggering. The migration to purely condition-based methodology is not yet complete and ultimately may not reduce the budget, but allocate funds more appropriately within the budget envelope to those assets requiring more regular maintenance as a result of age, operating conditions, and duty cycle.

**F-CCC-34**

**REF: Ex. F/T2**

Does PowerStream employ internal benchmarking measures beyond those identified in the DSP regarding distribution system planning and implementation work? If so, please provide a list of those measures.

**RESPONSE:**

PowerStream employs benchmarking measures as identified in the DSP and those identified in F-SEC-11.

**F-CCC-35**

**REF: Ex. G/T2/S1 section 5.2.3 Page 4 of 19 Performance Measurement for Continuous Improvement**

Re: DS Plan Spending Progress Report

The evidence states that PowerStream will be monitoring its execution of the projects and programs included in the DS Plan. On an annual basis, PowerStream's will calculate for that year, and on a cumulative basis for the five years of the DS Plan, its actual capital spending compared to the approved capital budget. As this is the first DS Plan filing, there are no historical statistics.

How will PowerStream be held accountable if the actual capital spending in any year is above the approved capital budget?

**RESPONSE:**

Please see the response to A-CCC-4.

**F-CCC-36**

**REF: Ex. G/T 2/S1/section 5.2.3 Page 4 of 19 Performance Measurement for Continuous Improvement**

Re: Work Order Closing Variances

On an annual basis, PowerStream's will calculate for that year, how successful the variances on individual work orders were. PowerStream will review the variance reports and determine if incremental improvements have transpired, and based on the results, take corrective actions as are deemed necessary.

Is this the method PowerStream is using to determine if it has met its Productivity goals? If not, how will the utility measure whether it has met its goals?

**RESPONSE:**

Please see the response to A-CCC-8.

**F-CCC-37**

**REF: Ex. G/T2/S1 section 5.2.3 Page 9 of 19 Performance Measurement for Continuous Improvement**

Re: Reliability Performance

On an annual basis, PowerStream reviews its reliability indices and looks at programs or projects that could be implemented to improve these metrics. An annual report is prepared, projects/programs presented and selected, and monitoring of progress is performed monthly.

This application is based on forecasted OM&A and Capital expenditures for 2016 -2020. How will PowerStream accommodate new projects/programs as described above?

**RESPONSE:**

PowerStream's business and budgeting processes involve longer term planning and forecasting with an annual update process. Each year PowerStream updates the capital and operating budgets based on current information and conditions including updating and running the capital optimization tool to make the best use of limited resources.

**F-CCC-38**

**REF: Ex. G/T2/S1 section 5.3.3 Page 28 of 38 Asset Lifecycle Optimization Policies and Procedures**

Re: Vegetation Management

Further vegetation management strategies were recommended by the System Hardening review as a result of the ice storm. PowerStream has changed its policy for rear yards and heavily treed front yards from a five year cycle to a 2 year cycle. Rural areas now have a 4 year tree trimming cycle where previously they were not part of the tree trimming cycle.

Please provide the OM&A and Capital costs for each year of the plan if the policy for rear yards and heavily treed front yards was moved from a five year cycle to a 4 year cycle as well as a five year cycle to a 3 year cycle.

Did PowerStream consider any other vegetation management scenarios?

**RESPONSE:**

Late in 2012, after the filing of PowerStream's 2013 Cost of Service Application, the policy for vegetation management for all areas was adjusted from a 5-year cycle to a 3-year cycle in order to focus on a more proactive program, harmonise practices across all service territories, and better align with best utility practices.

In 2015, PowerStream further enhanced its vegetation management program as a result of the ice storm review by modifying the trimming cycles as follows:

- Extend rural territory from a 3 year to a 4-year cycle
- Reduce rear lot services from a 3 year to a 2-year cycle
- Maintain urban areas at the 3-year cycle

As requested, the estimated comparative OM&A costs for theoretically moving the rear yards and heavily treed front yards from a 5-year to a 4-year cycle and from a 5-year cycle to a 3-year cycle are shown in the table below. There are no capital costs in relation to this program therefore only OM&A costs are included. There were assumptions made in calculating this data, as explained in the text following the table.

**Table F-CCC-38: Cost of New Tree Trimming Cycles**

| Year | Increased Expenses 5-year to 4-year cycle | Increased Expenses 5-year to 3-year cycle |
|---|---|---|
| 2015 | $ 92,766 | $ 247,376 |
| 2016 | $ 93,693 | $ 249,849 |
| 2017 | $ 94,630 | $ 252,348 |
| 2018 | $ 95,577 | $ 254,871 |
| 2019 | $ 96,532 | $ 257,420 |
| 2020 | $ 97,498 | $ 259,994 |

The data presented above was derived by simply taking the costs currently incurred in the 3 year cycle for rear yards and heavily treed front yards and prorating it over a 4-year and 5-year cycle. This estimate assumes that forestry crews would work in exactly the same way, utilize the same equipment, and that the same cutbacks would be achieved regardless of the cycle involved. However, the risk of extending this cycle is that larger cutbacks would be required, which would increase costs as well as being impractical in many situations.

The experience of the 2013 Ice Storm demonstrated that more focus was required in these areas, which led to the decision to implement a 2-year cycle. A longer cycle, such as a 4- or 5-year cycle, would not be effective in allowing PowerStream to meet its objectives of employees and public safety, reliability, and customer service.

**F-CCC-39**

**REF: Ex. G/T2/S1/section 5.4.2**

Please provide the customer satisfaction surveys and results for the period 2011-2014. Please provide the Customer Experience Plan undertaken in 2012.

**RESPONSE:**

Please see F-CCC-39 Appendix A 1-6 for customer satisfaction surveys and results for 2011-2014

Please see F-CCC-39 Appendix B for the Customer Experience Plan for 2012

**F-CCC-40**

**REF: Ex. G/T2/S1/section 5.4.2, p. 5**

Please provide the third-party report that was undertaken following the 2013 ice storm.

**RESPONSE:**

This report is attached as G-SEC-19 Appendix B.

**F-CCC-41**

**REF: Ex. G/T2/S1/section 5.4.2, p. 7**

Please set out historical amounts and budget amounts for PowerStream's CDM activities for the years 2011-2020. Are these costs in the forecasts for the plan term or are these activities funded through the IESO and removed from the revenue requirement? Please explain, in detail, the full scope of activities PowerStream undertakes with respect to CDM.

**RESPONSE:**

The table below sets out the actual historical amounts and IESO program cost budget amounts for PowerStream's CDM programs (including Collus PowerStream) for the years 2011-2020. In 2013, PowerStream offered delivery and strategic development services to Collus PowerStream. PowerStream entered into a delivery arrangement with Collus to assist in the delivery of their 2011-2014 OPA-Contracted Province Wide Programs. Costs to assist with the delivery of Collus' programs were recovered through the OPA via Collus' Program Administrative Funding. Actual costs reflect costs incurred from 2011-2014 for the OPA Province-Wide Contracted Programs. Costs for 2015-2020 include the OPA Province-Wide Contracted Program Extension budget of $17.2M, the PowerStream 'Conservation first' Framework six year budget of $140.7M and the delivery of Collus PowerStream 'Conservation First' Framework six year budget of $4.4M.

| ($ million) | 2011 Actual | 2012 Actual | 2013 Actual | 2014 Actual | 2015 Budget | 2016 Budget | 2017 Budget | 2018 Budget | 2019 Budget | 2020 Budget | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| PowerStream 2015-2020 Conservation First Framework | | | | | $ 8.3 | $ 16.8 | $ 19.1 | $ 32.2 | $ 32.0 | $ 32.3 | $ 140.7 |
| Collus 2015-2020 Conservation First Framework | | | | | $ 0.3 | $ 0.5 | $ 0.6 | $ 1.0 | $ 1.0 | $ 1.0 | $ 4.4 |
| 2011-2014 OPA Province wide contracted program extension | | | | | $ 13.4 | $ 3.9 | | | | | $ 17.3 |
| 2011-2014 OPA Province wide contracted program | $ 9.9 | $ 10.4 | $ 20.0 | $ 24.2 | | | | | | | $ 64.5 |
| Total CDM | $ 9.9 | $ 10.4 | $ 20.0 | $ 24.2 | $ 22.0 | $ 21.2 | $ 19.7 | $ 33.2 | $ 33.0 | $ 33.3 | $ 226.9 |

The budget costs for 2015-2020 are all funded by the IESO and are not included in the calculation for revenue requirement for the rate plan.

PowerStream continues to deliver conservation initiatives to its customers based on the 2015-2020 ‘Conservation First’ framework (announced by Minister of Energy on March 31, 2014). PowerStream delivers CDM initiatives funded through the IESO. PowerStream has been allocated a 6-year CDM target of 535.44 GWh of energy savings persisting at the end of 2020 and a budget of $140.7M.

PowerStream is also entering into an agreement with Collus PowerStream to provide fully integrated turn-key CDM delivery services in Collus PowerStream’s territory. PowerStream will manage 95% of Collus PowerStream’s 6-year CDM Budget of $4.4M, in order to achieve their target of 16.86 GWh of energy savings.

As 2015 will be a transition year between the current and future CDM funding frameworks in Ontario, the OPA has extended the 2011-2014 CDM Master Agreement through to the end of 2015. This budget is $17.2M including Collus.

**F-CCC-42**

**REF: Ex. G/T2/S1/ section 5.4.2, p. 7**

Please identify the full costs of the work undertaken by Innovative Research Inc. How were those costs recovered? Are any of those costs embedded in the 2016-2020 forecasts? If so, please identify where those costs are in the OM&A budgets.

**RESPONSE:**

The full cost of the work undertaken by Innovative Research Inc. was $266,764.21

Costs were largely recovered in 2014 and 2015 out of current rates. These costs do not factor into the 2016-2020 application.

**F-CCC-43**

**REF: Ex. G/T2/S1/ section 5.4.2, p. 9**

There is a statement in the evidence which concludes that in terms of the customer engagement "customers generally accepted the proposed rate increases, but there was a concern from some business customers that PowerStream had not demonstrated that they looked for internal efficiencies prior to going to customers for the increase." In the context of these engagement activities did PowerStream or Innovative discuss distribution rate increases rather than bill increases with the customers? If not, why not? Were customers made aware of the fact that other components of the bill would be rising as well over the plan term?

**RESPONSE:**

PowerStream's engagement activities described rate increases in the context of distribution rates only. Bills were broken up into their individual components, and it was explained that PowerStream retains only distribution charges which are collected with transmission charges in the delivery portion of the bill. In the context on the entire bill, it was stated that other items on customers' bills may increase.

**F-Energy Probe-6**

**REF: Ex. F, Tab 1, Table 5**

a) Please provide the source of the inflation factors shown in Table 5.

b) Please provide the source of the customer growth factors shown in Table 5 and show how they relate the customer numbers used in Exhibit H.

c) What does PowerStream mean by the line in Table 5 called Customer Growth effect on OM&A and please explain fully how the 11.45% figure is derived, including any calculations used.

**RESPONSE:**

a) The inflation factors shown for 2014 and 2015 are the inflation factors (IPI) issued by the Board to be used in the price cap formula in IRM rate applications for each of those years.

   The inflation factors shown for 2016 to 2020 are estimated based on a simple average of the annual wage increase in PowerStream's current union labour contract of 2.75%, which is in effect until March 31, 2016, and the average OEB inflation factor of 1.65%. The 1.65% was derived by averaging the 2014 and 2015 OEB IPI rates of 1.7% and 1.6% respectively.

b) The customer growth percentages from 2016 to 2020 (i.e. 1.69% in 2016, 1.72% in 2017 1.70% in 2018, 1.70% in 2019 and 1.72% in 2020) are taken from Exhibit H, Tab 4, "Table 7: Billing Determinants – Customers and Connections". The percentages represent the change in customer count for each year compared to the prior year.

c) The 11.45% figure is based on a methodology developed to determine the impact on OM&A as a result of customer growth. The methodology incorporates 2013 actual OM&A costs as a base. The OM&A costs were then separated out by business units and a correlation was made whether an increase in customers would increase that business unit's OM&A. Each business unit was then given a percentage rating of high (40%), medium (20%) and low (5%) based on the likelihood that the OM&A costs would increase if customers increased. A high correlation was determined for work programs such as Customer Billing and Customer Relations and Credit based on activities, supplies and materials directly needed to address an increase in customers. A medium correlation was determined for Lines and Engineering Management through the assessment of work programs that will be impacted by the growth in plant needed to service an increase in customers. A low correlation included back office work activities that are not externally customer orientated, (e.g. Finance and Corporate Services).

The high, medium and low percentages were applied to the 2013 OM&A costs and 11.45% was determined to be the growth effect on OM&A. 11.45% was then multiplied by the average customer growth of 1.71% (simple average of the percentages from 2016 – 2020 discussed in b) above), which resulted in a 0.20% customer growth effect on OM&A. Therefore, OM&A costs will increase by 0.2% when the average customer growth of 1.71% is experienced. F-Energy Probe-6 Appendix A provides the details for the calculation of the 11.45% and 0.20% factors respectively.

**F-Energy Probe-7**

**REF: Ex. F, Tab 1, Table 6**

a) Please confirm that the figures shown in Table 6 are all incremental on a year to year basis. For example, the $614 shown in 2016 for vegetation management is incremental to the amount spent in 2015, which in turn was $300 above the level of expenditures in 2014.

b) Please provide a table similar to Table 6 that shows the total costs, rather than the incremental costs, for the lines noted. In providing this table, please start with 2013 actual figures.

**RESPONSE:**

a) Yes. The figures in Exhibit F, Tab 1, Table 6 are all incremental on a year to year basis.

b) Refer to the below table, showing cumulative total costs starting from 2013 Actual Figures in (000's):

| | | | | Custom IR Term | | | | |
|---|---|---|---|---|---|---|---|---|
| | Actual 2013 (Total) | Actual 2014 (Total) | 2015 Bridge Year (Total) | 2016 (Total) | 2017 (Total) | 2018 (Total) | 2019 (Total) | 2020 (Total) |
| New CIS incremental costs * | $0 | $1,349 | $2,659 | $2,537 | $2,379 | $2,197 | $2,198 | $2,200 |
| Vegetation management | $1,461 | $1,760 | $2,060 | $2,674 | $3,200 | $3,731 | $4,267 | $4,809 |
| Compliance | $1,057 | $1,319 | $1,504 | $1,636 | $1,654 | $1,672 | $1,690 | $1,710 |
| Risk Management | $2,677 | $3,007 | $3,764 | $4,282 | $4,767 | $4,731 | $4,869 | $4,766 |
| Customer expectation | $2,341 | $3,095 | $2,848 | $2,905 | $2,930 | $2,955 | $2,980 | $3,005 |
| **Total** | **$7,536** | **$10,530** | **$12,835** | **$14,035** | **$14,930** | **$15,286** | **$16,005** | **$16,490** |

* - New post 2013, hence no budget

## F-Energy Probe-8

## REF: Ex. F, Tab 1, page 6

The evidence states that injection costs less than 10% of the cost of replacement and injected cable lasts 40% of the estimated life of 50 years for replacement cable. Based on these figures, please show how the cost of 40% for injected cable versus replacement cable has been estimated.

**RESPONSE:**

Both cable replacement and cable injection are performed by contractors, and include labour, equipment and materials. The injection cost of 10% of the replacement cost is the actual cost to complete the work.

The 40% represents estimated life, as compared to new cable, and is not used in the calculation of the cost above. The 40% of the estimated life of 50 years represents the 20 year life extension that the vendor warranties.

**F-Energy Probe-9**

**REF: Ex. F, Tab 2, Table 1**

a) Please provide a live Excel spreadsheet that includes all of the data used to generate the predicted total costs in Table 1.

b) If available, please update Table 1 to include actual costs for 2014.

c) Please explain why PowerStream is forecasting to be above the predicted total costs in 2014 through 2020 when it has historically always been under the predicted total.

d) Please explain how the forecast total, OM&A and actual capital costs have been calculated both historically and over the forecast period.

**RESPONSE:**

a) The live Excel spreadsheet that includes all of the data used to generate the predicted total costs in Exhibit F, Tab 2, Table 1 is attached as F-Energy Probe-9 Appendix A.

b) PowerStream has used the PEG model to derive future values of predicted costs and compare them to actual and forecasted costs using the PEG's definitions of Capital and OM&A costs, updating it with the 2014 actuals for OM&A and Capital Additions. The results are shown in Table 1 below.

**Table 1: Predicted vs. Actual (and Forecasted) Costs ($000)**

| Year | Predicted Total Costs | Actual Total Costs | Actual OM&A | Actual Capital |
|---|---|---|---|---|
| **2010** | 212,561 | 196,831 | 51,332 | 145,499 |
| **2011** | 218,280 | 204,310 | 54,882 | 149,428 |
| **2012** | 216,915 | 207,288 | 58,480 | 148,808 |
| **2013** | 219,646 | 212,560 | 60,250 | 152,309 |
| **2014** | **234,087** | **233,194** | **62,119** | **171,075** |
| **2015** | 241,962 | 252,487 | 69,674 | 182,814 |
| **2016** | 250,890 | 267,801 | 70,309 | 197,492 |
| **2017** | 260,721 | 281,862 | 72,465 | 209,398 |
| **2018** | 274,073 | 297,945 | 75,437 | 222,507 |
| **2019** | 288,617 | 313,082 | 77,734 | 235,348 |
| **2020** | 303,449 | 327,765 | 79,734 | 248,030 |

c) PowerStream is experiencing substantial changes in operating conditions as compared to the previous year. For example, there are substantial increases in the capital costs related to sustainment of assets; replacement of capital stock and distribution infrastructure, some of which was financed by contributed capital and therefore never attracted a depreciation charge; extraordinary expenditures like a new transformer station; and a new Customer Information System, which requires substantial initial investments.

There are significant net incremental new costs in 2014 and 2015 related primarily to the new customer billing and information system ("CIS"), system hardening to better withstand storms and increased costs to meet customer expectations and compliance requirements. The need for increased capital spending on sustainment causes the capital portion of Actual (and forecasted) cost to continue to rise faster than predicted costs until 2018-2019. At this point the Actual costs and predicted costs are increasing at the same rate.

d) The Board has determined that the Pacific Economic Group (PEG) econometric model will be used for benchmarking distributor cost performance and for informing the Board's annual assignment of stretch factors to distributors. Given reasonable expectations about future values of output, input prices, and business conditions, the econometric cost model above can be used to forecast future values of predicted costs. PowerStream performed the following steps to derive the predicted cost:

**Step 1: Compute Projections of Relevant Variables**

<u>OM&A Price Index</u>

The OM&A Price index constructed as a weighted average of a labor and non-labor component, with the weights determined by the Board to reflect the historical share of labor and non-labor OM&A expenses in the Ontario electricity distribution industry. Specifically, 70/30 AWE/GDPIPI split, where AWE is Statistics Canada's Average Weekly Earnings for all workers in Ontario, used for the labor price component, and GDPIPI is Statistics Canada's Ontario Gross Domestic Product Implicit Price Index for Final Domestic Demand, used for the non-labor component. Future values of AWE were forecasted out from a reference year of 2013 based on the 5-year historic average growth rate (1.872%) of AWE. Future values of each GDPIPI were forecasted out from a reference year of 2014 based on the 5-year historic average growth rate (1.580%) of GDPIPI.

<u>Capital Price Index</u>

The Capital Price index is a constructed variable based on Depreciation, EUCPI, and WACC. Rate of depreciation is set at 4.59%. Future values of EUCPI (Statistics Canada's Electric Utility Construction Price Index) were forecasted out from a reference year of 2014 using the 10-year historic average growth rate (2.04%) of EUCPI. WACC is the Weighted Average Cost of Capital for Ontario distributors, as computed by the Board. WACC was assumed to be fixed at its 2015 value (6.48%).

Outputs

Output is measured in terms of number of customers; system capacity, as proxied by peak demand; and deliveries. PowerStream forecasted each of these variables based on its internal knowledge of its customer base and service territory.

Business Conditions

The relevant business condition variables are average distribution line length, percent of customers added in last 10 years, and a time trend. Given the forecast of the number of customers, it is straightforward exercise to forecast the first two of these business conditions. The time trend is simply a time index which begins in 2007.

**Step 2: Acquire the Sample Means of each variable**

**Step 3: Acquire parameters from the model specific to the LDC**

- Table 16 of PEG's Final Report lists the estimated parameters from the industry model (i.e. including all distributors).

**Step 4: Construct Predicted Costs**

- Construct Econometric Variables
- Construct relative capital price;
- Mean normalize each variable using its 2002-2013 samples mean;
- Construct logs;
- Construct higher order and interaction terms.
- Construct Linear Prediction
- Multiply each econometric variable by its corresponding LDC specific parameter (Step 3) and then sum over all the products.
- Construct Predicted Costs
- Predicted Total Cost is equal to the exponential of the linear prediction, and then scaled up by OM&A Price Index (Step 1).

PowerStream performed the following steps to derive the actual cost:

**Step 1: Derive OM&A Costs**

OM&A costs consist of operation, maintenance, billing and collection, community relations, administrative and general expenses, insurance expenses, and advertising expenses. These costs are adjusted by subtracting any HV expenses, and adding back any LV costs. For the years 2014 to 2020, forecasts of operations costs equals budgeted costs. HV adjustments for the years 2014-2020 were assumed to be constant at 600,000. Estimation of 2014-2020 LV costs was based on the cost of power forecast, Account 4750.

**Step 2: Derive Capital Costs**

Capital costs are defined as the product of the quantity of capital and the capital price. Capital prices - forecasted values of capital prices for the years 2014-2020, are the same values that were used to construct the Predicted costs. Projections of capital additions were obtained from the capital budget and match capital additions used for rate base calculations.

**F-Energy Probe-10**

**REF: Ex. F, Tab 2**

a) How did PowerStream determine which distributors to include in the comparisons shown in Figures 2 through 4?

b) Please explain why the following distributors were not included in the comparison: Entegrus, Bluewater, St. Thomas, Brantford Power, Waterloo North, Kitchener-Wilmot and Cambridge North Dumfries.

c) Please provide a table and a figure that shows the total cost per customer for the distributors used by PowerStream, along with those listed in part (b) above.

**RESPONSE:**

a) PowerStream prepares this rate comparison annually as part of its own internal processes to monitor its rates compared to other distributors. PowerStream selected what it believes to be a representative sample of distributors.

b) A number of different criteria were used in making this selection: proximity to PowerStream's service areas, inclusion of other members of the Coalition of Large Distributors and inclusion of other utilities that are thought to have some similarities, i.e. mainly urban, medium sized utilities such as London and Guelph.

c) The listed distributors were not included as they did not meet the criteria used as described in part (a) above.

d) The updated total cost (total bill) per customer charts, as well as the requested data tables are presented below.

**Figure F-EP-10-1: 2014 Typical Residential Customer Bill Comparison**

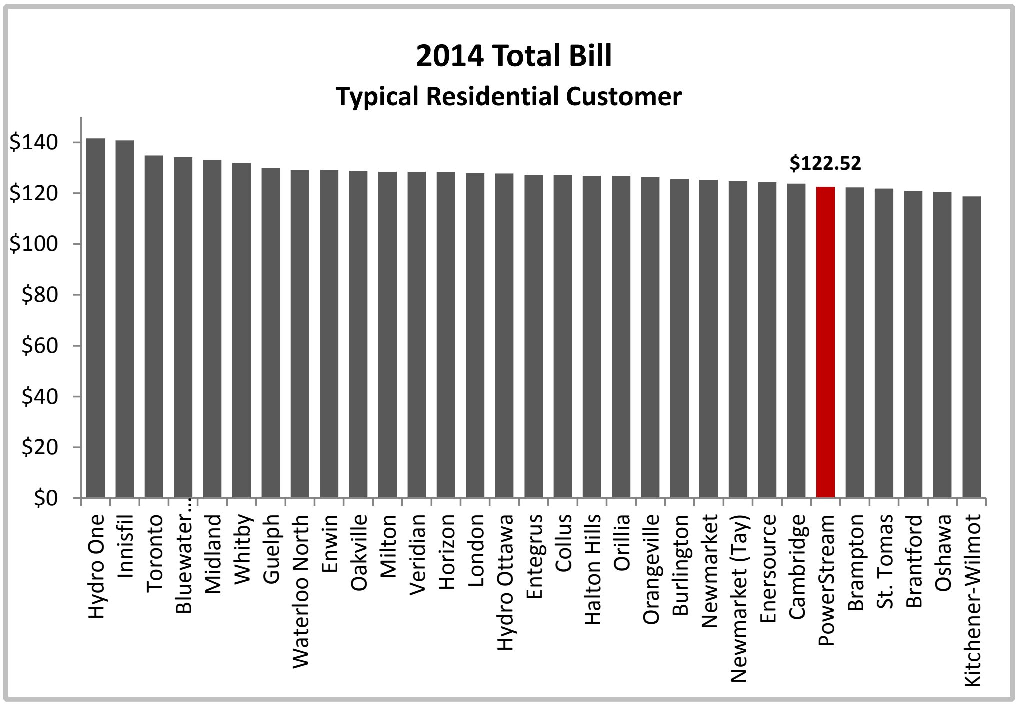



**Table F-EP-10-1: 2014 Typical Residential Customer Bill Comparison**

| 1st Quartile | | 3rd Quartile | |
|---|---|---|---|
| Hydro One | 141.56 | Orillia | 127.03 |
| Innisfil | 140.76 | Hydro Ottawa | 126.85 |
| Toronto | 134.86 | London | 126.79 |
| Bluewater Power | 134.20 | Orangeville | 126.30 |
| Midland | 133.00 | Burlington | 125.43 |
| Whitby | 131.87 | Newmarket | 125.31 |
| Guelph | 129.86 | Newmarket (Tay) | 124.74 |
| Waterloo North | 129.16 | Enersource | 124.37 |
| **2nd Quartile** | | **4th Quartile** | |
| Collus | 129.09 | Cambridge | 123.73 |
| Oakville | 128.82 | **PowerStream** | **122.52** |
| Veridian | 128.46 | Brampton | 122.26 |
| Guelph | 128.40 | St. Tomas | 121.87 |
| Milton | 128.36 | Brantford | 120.95 |
| Halton Hills | 127.92 | Oshawa | 120.55 |
| Horizon | 127.70 | Kitchener-Wilmot | 118.78 |
| Entegrus | 127.11 | Wasaga | 112.10 |

**Figure F-EP-10-2: 2014 Typical GS<50 Customer Bill Comparison**

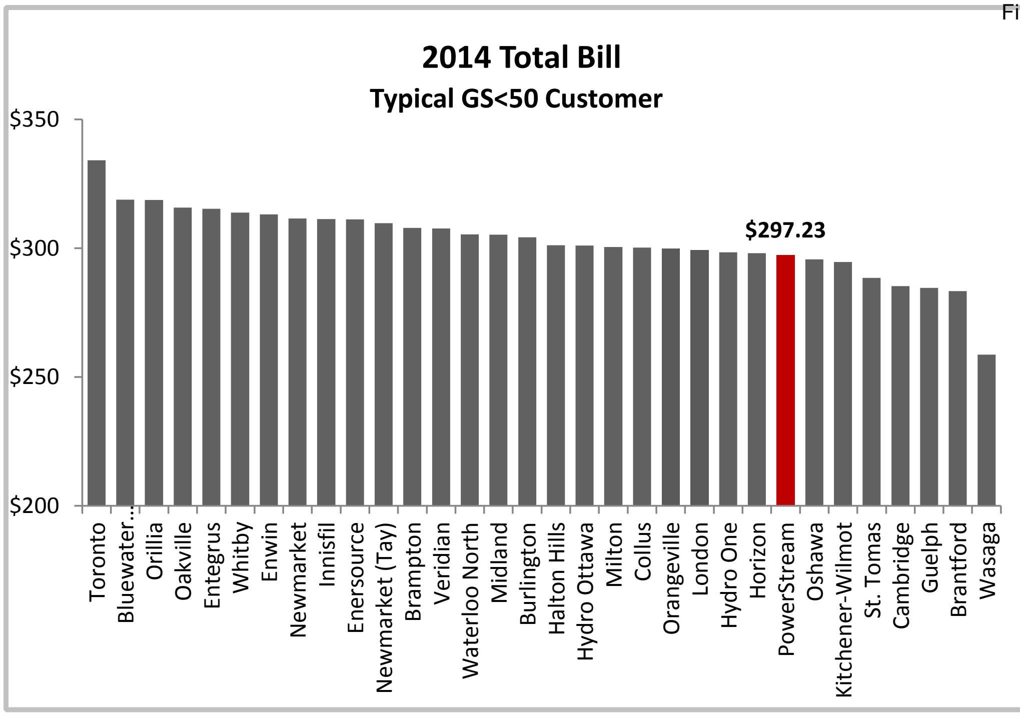



**Table F-EP-10-2: 2014 Typical GS<50 Customer Bill Comparison**

| 1st Quartile | | 3rd Quartile | |
|---|---|---|---|
| Toronto | 334.13 | Halton Hills | 301.10 |
| Bluewater Power | 318.88 | Hydro Ottawa | 301.05 |
| Orillia | 318.76 | Milton | 300.49 |
| Oakville | 315.71 | Collus | 300.26 |
| Entegrus | 315.32 | Orangeville | 299.78 |
| Whitby | 313.78 | London | 299.31 |
| Enwin | 313.13 | Hydro One | 298.39 |
| Newmarket | 311.53 | Horizon | 298.02 |
| **2nd Quartile** | | **4th Quartile** | |
| Innisfil | 311.37 | **PowerStream** | **297.23** |
| Enersource | 311.22 | Oshawa | 295.68 |
| Newmarket (Tay) | 309.70 | Kitchener-Wilmot | 294.69 |
| Brampton | 307.93 | St. Tomas | 288.45 |
| Veridian | 307.68 | Cambridge | 285.32 |
| Waterloo North | 305.38 | Guelph | 284.64 |
| Midland | 305.23 | Brantford | 283.31 |
| Burlington | 304.24 | Wasaga | 258.73 |

**Figure F-EP-10-3: 2014 Typical GS>50 Customer Bill Comparison**

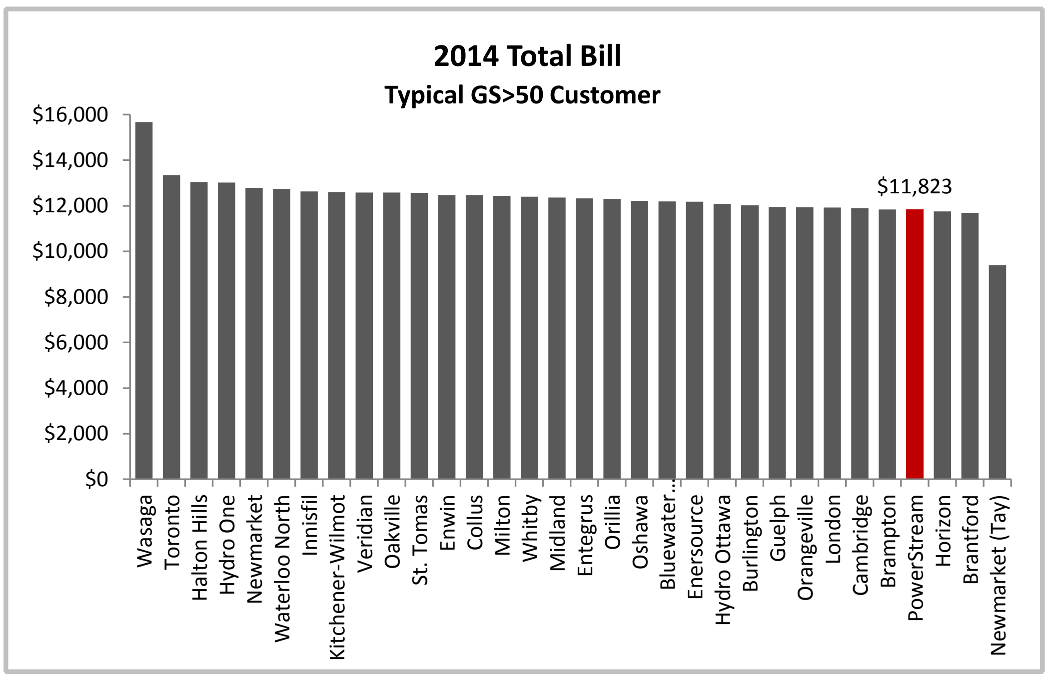



**Table F-EP-10-3: 2014 Typical GS>50 Customer Bill Comparison**

| 1st Quartile | | 3rd Quartile | |
|---|---|---|---|
| Wasaga | 15,672.66 | Entegrus | 12,318.73 |
| Toronto | 13,343.97 | Orillia | 12,302.60 |
| Halton Hills | 13,036.58 | Oshawa | 12,209.79 |
| Hydro One | 13,017.54 | Bluewater Power | 12,193.17 |
| Newmarket | 12,789.03 | Enersource | 12,179.62 |
| Waterloo North | 12,737.53 | Hydro Ottawa | 12,079.20 |
| Innisfil | 12,631.36 | Burlington | 12,007.01 |
| Kitchener-Wilmot | 12,609.37 | Guelph | 11,941.88 |
| **2nd Quartile** | | **4th Quartile** | |
| Veridian | 12,582.43 | Orangeville | 11,935.42 |
| Oakville | 12,574.86 | London | 11,921.00 |
| St. Tomas | 12,569.61 | Cambridge | 11,903.13 |
| Enwin | 12,475.94 | Brampton | 11,833.58 |
| Collus | 12,467.05 | **PowerStream** | **11,822.59** |
| Milton | 12,436.71 | Horizon | 11,748.74 |
| Whitby | 12,393.38 | Brantford | 11,691.64 |
| Midland | 12,364.90 | Newmarket (Tay) | 9,385.58 |

**F-SEC-6**

**REF: EX. F-1, p.4**

With respect to the excepted vs estimated product savings:

a. Please confirm that the estimated productivity savings set out in Table 2 are incremental savings per year, not cumulative savings.

b. Please revise Table 3 to only include savings for 2017-2020.

**RESPONSE:**

a) PowerStream cannot confirm this.

Exhibit F, Tab 1, Table 2 is a summary of the annual capital and OM&A estimated productivity savings. These totals are compared in Table 3 to the “OEB Expected Productivity Savings” which come from Table 1.

The “OEB Expected Productivity Savings” from Table 1 are annual targets, e.g. year two expected productivity savings are equal to the productivity savings, based on the X in the IRM IPI-X price cap formula for both years 1 and 2. The productivity factor under IRM reduces the revenue requirement collected in rates in year two by both the year 1 and the year 2 productivity reductions. The Table 1 annual amounts are cumulative.

The estimated productivity savings from OM&A in Table 4 and summarized in Table 2 have been calculated on the same basis. For example the OM&A productivity savings for 2020 of $3.0 million are comparable to the OEB Expected Productivity Savings from Table 1 and Table 3 for 2020 of $3.2 million, i.e. measured in terms of the impact on revenue requirement in the year.

In responding to this question PowerStream realized that the “Additional Productivity Savings from Capital” presented in Table 2 were not calculated on a revenue requirement basis and these amounts are incremental not cumulative. This must be restated for the capital productivity savings to be properly compared with the OEB Expected Productivity Savings based on the IRM X factor.

In the tables below, PowerStream has restated the capital savings to reflect the revenue requirement reduction rather than the capital savings. The amounts also reflect the pattern that the capital savings in 2016 reduce revenue requirement in years 2016 to 2020, capital savings in 2017 reduce revenue requirement in years 2017 to 2020 and so on.

Table F-SEC-6-1 is a restated version of Table 2 with the savings from capital calculated on a comparable basis to OEB Expected Productivity Savings.

**Table F-SEC-6-1: Estimated Productivity Savings ($ Millions)**

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | Total |
|---|---|---|---|---|---|---|---|---|
| Capital | | $0.4 | $0.8 | $1.2 | $1.6 | $2.1 | $2.6 | $8.6 |
| OM&A | $2.5 | ($0.8) | ($1.0) | $0.3 | $1.2 | $2.0 | $3.0 | $7.2 |
| **Total** | **$2.5** | **($0.4)** | **($0.2)** | **$1.5** | **$2.8** | **$4.1** | **$5.6** | **$15.8** |

Table F-SEC-6-2 is a restated version of Table 3 incorporating the revised estimated productivity savings from Table F-SEC-6-1.

**Table F-SEC-6-2: Expected vs. Estimated Productivity Savings ($ Millions)**

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | Total |
|---|---|---|---|---|---|---|---|---|
| OEB Expected Productivity Savings | $0.5 | $0.9 | $1.4 | $1.9 | $2.3 | $2.8 | $3.2 | $13.0 |
| Estimated Productivity Savings | $2.5 | ($0.4) | ($0.2) | $1.5 | $2.8 | $4.1 | $5.6 | $15.8 |
| **Over (under) achieved** | **$2.0** | **($1.4)** | **($1.6)** | **($0.4)** | **$0.5** | **$1.3** | **$2.4** | **$2.9** |

Tables F-SEC-6-3 and F-SEC-4 show the calculation of the productivity savings from capital measured in terms of reduced revenue requirement.

**Table F-SEC-6-3: Capital Savings Impact on Revenue Requirement ($ Millions)**

| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|
| Capital Savings | $ 3.80 | $ 4.10 | $ 4.50 | $ 4.70 | $ 5.00 | $ 5.00 |
| Cumulative savings | $ 3.80 | $ 7.90 | $ 12.40 | $ 17.10 | $ 22.10 | $ 27.10 |
| Reduced revenue requirement: | | | | | | |
| Return on Rate base (WACC 6.0%) | $ 0.23 | $ 0.47 | $ 0.74 | $ 1.03 | $ 1.33 | $ 1.63 |
| Depreciation | $ 0.08 | $ 0.18 | $ 0.28 | $ 0.38 | $ 0.49 | $ 0.60 |
| Taxes | $ 0.05 | $ 0.11 | $ 0.17 | $ 0.23 | $ 0.30 | $ 0.36 |
| Decreased Revenue Requirement | $ 0.36 | $ 0.76 | $ 1.19 | $ 1.64 | $ 2.11 | $ 2.59 |

**Note: Results from this table rounded to one decimal place in Table F-SEC-6-1 above.**

**Table F-SEC-6-4: Capital Savings Impact on Revenue Requirement – Tax Calculation ($ Millions)**

| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|
| Equity (@40% of rate base) | $ 1.52 | $ 3.16 | $ 4.96 | $ 6.84 | $ 8.84 | $ 10.84 |
| Return on equity | 8.93% | 9.30% | 9.30% | 9.30% | 9.30% | 9.30% |
| Reduction to target net income | $ 0.14 | $ 0.29 | $ 0.46 | $ 0.64 | $ 0.82 | $ 1.01 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Taxes at 26.5% | $ 0.04 | $ 0.08 | $ 0.12 | $ 0.17 | $ 0.22 | $ 0.27 |
| Taxes with gross up | $ 0.05 | $ 0.11 | $ 0.17 | $ 0.23 | $ 0.30 | $ 0.36 |

b) Table F-SEC-6-5 is an updated version of Table 3 presenting only the productivity savings for 2017 to 2020.

**Table F-SEC-6-5: Expected vs. Estimated Productivity Savings ($ Millions)**

| | 2017 | 2018 | 2019 | 2020 | Total |
|---|---|---|---|---|---|
| OEB Expected Productivity Savings | $ 1.9 | $ 2.3 | $ 2.8 | $ 3.2 | $ 10.2 |
| Estimated Productivity Savings | $ 1.5 | $ 2.8 | $ 4.1 | $ 5.6 | $ 14.0 |
| **Over (under) achieved** | -$ 0.4 | $ 0.5 | $ 1.3 | $ 2.4 | $ 3.8 |

**F-SEC-7**

Please provide a copy of the following documents:

a. The budget guidance documents provided to departments in their preparation for setting the 2006-2020 budgets.

b. The business plan that underpins the proposed 2016-2020 budgets.

**RESPONSE:**

a) The budget guidance document is provided as F-SEC-7 Appendix A

b) PowerStream does not have a business plan document. PowerStream's corporate strategy map and critical success factors underpins the proposed budgets. These are included as F-SEC-7 Appendix B and F-SEC-7 Appendix C

**F-SEC-8**

**REF: Ex. F-1, p.4**

Does PowerStream have a plan at this time to meet the specific incremental productivity savings for each year between 2016-2020? If so, please provide details.

**RESPONSE:**

Please see the response to A-CCC-8.

**F-SEC-9**

**REF: Ex. F-1, p.7**

Please provide a copy of the most recent CIS Project business case.

**RESPONSE:**

Please see response to B-CCC-15.

**F-SEC-10**

**REF: Ex. F-1, p.7**

Please provide a copy of the most recent Work Force Management business case.

**RESPONSE:**

Please see Work Force Management Business Case attached as F-SEC-10 Appendix A.

**F-SEC-11**

**REF: Ex. F-2**

Please provide copies of all benchmarking studies, reports, and analysis undertaken by Powerstream itself or by a third-party, that are not already included in the materials provided.

**RESPONSE:**

PowerStream participates in two benchmarking surveys:

- CEA 2013 Service Continuity Data on Distribution System Performance in Electrical Utilities, Composite, Non-Confidential
- MEARIE 2014 Utility Performance Management Survey (UPM)

The CEA report is provided as F-SEC-11 Appendix A. MEARIE has agreed to its reports being provided on a confidential basis. The MEARIE UPM reports are provided on a confidential basis as F-SEC-11 Appendices B-1 and B-2.

PowerStream also has a Key Process Scorecard that it uses for internal benchmarking. The current scorecard is provided as F-SEC-11 Appendix C

These activities are aligned to PowerStream's continuous improvement philosophy and belief that what gets measured gets better. These activities are undertaken by PowerStream in order to determine what and where improvements are called for. We have also indicated below, how this information is currently used to improve PowerStream's performance.

**Key Process Scorecard**

PowerStream's Corporate Key Processes have been defined as those processes critical to delivering power to customers and receiving prompt payment for services. Consideration of PowerStream's Vision and Mission were a fundamental component in the identification and development of PowerStream's Key Processes and Sub Processes.

Key processes were identified using the experience of PowerStream's Senior Leadership Team (SLT) and other key stakeholders at a series of working group meetings. In total 5 Key Processes were identified along with 24 Sub-Processes that directly supported or enabled the Key Processes.

In 2013 the inaugural version of PowerStream's monthly Key Process Scorecard was launched. In collaboration with Engineering, Operations & Construction and Customer Service, 17 Key Process Measures were defined and target performance levels were established. A variety of methods were used to establish targets including alignment with PowerStream strategy, other LDC performance, OEB targets, existing areas of opportunity, continuous improvement culture.

How the information is used:

- Annual review with senior Division leaders to assess performance against target as well as to discuss opportunities for improvement and/or target adjustments.
- Business process improvement opportunities discussed here. Manager BPI documents opportunities if material. Business Process Improvement initiatives reviewed annually during PowerStream's Business Planning process.
- At annual review meetings, performance against target is demonstrated via charts and graphs to assist in communicating the results
- Key Process Scorecard is distributed Corporate wide, shared at department meetings and made available on Corp. Intranet site.

See attached example of PowerStream's Key Process Scorecard results for December 2014.

## Annual MEARIE UPM Survey Results

PowerStream participates annually in the MEARIE survey along with approx. 24 other LDC's.

There are a total of 88 Ratios (Financial Performance, Customer Service, Efficiency, System Reliability, Resource Management) that are produced as a result of the data gathered during the annual survey. Each participant receives a customized performance scorecard showing PS's results over the last 3 years relative to the other 24 participants. Participants are categorized as Small, Medium & Large. In the 2013 survey there were 12 "Large Participants" (40,000 customers and above) including; Enersource, Horizon, Hydro One Brampton, Waterloo North, Kitchener, EnWin, Oakville, London, Veridian, Entegrus, Thunder Bay. Hydro Ottawa did not participate in 2013.

Results are presented in the MEARE "Ratios Report" and show last 3 years (2013, 2012, 2011) for each ratio for each of the 24 participants. This allows PS to see how it measures up in relation to the other participants. PS undertakes further analysis of 26 of the Key Metrics, utilizing Ratio data for each of the "Large Participants" (of which there are 12), in order to provide more relevant information for benchmarking analysis. PS reviews current performance vs prior year as well as the trend over the three year period. As well, PS reviews current performance relative to the "Large Participants" performance. And finally, PS reviews current performance versus "like" distributors that participated (Large City Southern High U/G category) i.e. Horizon, H1Brampton, London, Enersource.

This analysis of performance results has many purposes including:

- Providing the content for continuous improvement messages
- Bottom quartile results have been used to provide support for the initiation of improvement projects such as the Material Requirement Planning project with an objective to increase inventory turnover.
- Creating the impetus to do a deeper dive review when results appear unfavourable
- Opportunity to check in with cohorts who participate in the survey to see what they are doing to achieve their results and to assess interpretation of metric
- Opportunity to keep Senior PowerStream leaders abreast of available benchmarking data

2013 PowerStream results

- For most of the 26 key ratios, PowerStream's performance in 2013 had improved over 2012

In comparison to the other Large LDC's in the survey:

- PowerStream did have some below average and bottom quartile results in some of the metrics, however, in most of these cases, PowerStream results improved over the previous year.
- PowerStream has a below average monthly bill for 1000kWh residential customer.
- PowerStream's has one of the highest billing accuracy percentages
- PowerStream is a top performer in this group when it comes to Number of customers per FTE.
- PowerStream has below average overtime hours as a percent of regular hours
- Below average performance in Outage Minutes and # of interruptions per customer due to the December 2013 ice storm.

**F-SEC-12**

**REF: Ex. F-2, p.2**

Please provide the data files that PowerStream used to derive Table 1. Please provide a step-by-step explanation of how PowerStream derived future predicted costs from the PEG model.

**RESPONSE:**

The Board has determined that the Pacific Economic Group (PEG) econometric model will be used for benchmarking distributor cost performance and for informing the Board's annual assignment of stretch factors to distributors. Given reasonable expectations about future values of output, input prices, and business conditions, the econometric cost model above can be used to forecast future values of predicted costs. PowerStream performed the following steps to derive the predicted cost:

**Step 1: Compute Projections of Relevant Variables**

<u>OM&A Price Index</u>

The OM&A Price index constructed as a weighted average of a labor and non-labor component, with the weights determined by the Board to reflect the historical share of labor and non-labor OM&A expenses in the Ontario electricity distribution industry.

Specifically, 70/30 AWE/GDPIPI split, where AWE is Statistics Canada's Average Weekly Earnings for all workers in Ontario, used for the labor price component, and GDPIPI is Statistics Canada's Ontario Gross Domestic Product Implicit Price Index for Final Domestic Demand, used for the non-labor component. Future values of AWE were forecasted out from a reference year of 2013 based on the 5-year historic average growth rate (1.872%) of AWE. Future values of each GDPIPI were forecasted out from a reference year of 2014 based on the 5-year historic average growth rate (1.580%) of GDPIPI.

Capital Price Index

The Capital Price index is a constructed variable based on Depreciation, EUCPI, and WACC. Rate of depreciation is set at 4.59%. Future values of EUCPI (Statistics Canada's Electric Utility Construction Price Index) were forecasted out from a reference year of 2014 using the 10-year historic average growth rate (2.04%) of EUCPI. WACC is the Weighted Average Cost of Capital for Ontario distributors, as computed by the Board. WACC was assumed to be fixed at its
2015 value (6.48%).

Outputs

Output is measured in terms of number of customers; system capacity, as proxied by peak demand; and deliveries. PowerStream forecasted each of these variables based on its internal knowledge of its customer base and service territory.

Business Conditions

The relevant business condition variables are average distribution line length, percent of customers added in last 10 years, and a time trend. Given the forecast of the number of customers, it is straightforward exercise to forecast the first two of these business conditions. The time trend is simply a time index which begins in 2007.

**Step 2: Acquire the Sample Means of each variable**

**Step 3: Acquire parameters from the model specific to the LDC**

Table 16 of PEG's Final Report lists the estimated parameters from the industry model (i.e. including all distributors).

**Step 4: Construct Predicted Costs**

Construct Econometric Variables

- Construct relative capital price;
- Mean normalize each variable using its 2002-2013 samples mean;
- Construct logs;
- Construct higher order and interaction terms.

Construct Linear Prediction

- Multiply each econometric variable by its corresponding LDC specific parameter (Step 3) and then sum over all the products.

Construct Predicted Costs

- Predicted Total Cost is equal to the exponential of the linear prediction, and then scaled up by OM&A Price Index (Step 1).

As a data source, PowerStream utilized the Excel files named *PEG TFP and BM data calculations.xlsx* and *EB-2010-0379 PEG Price Cap IR BM Algorithm Tool.xlsx.* These files include all the data used in PEG's productivity and benchmarking research, the results of PEG's index-based input price and productivity computations, and related workpapers. The files are attached as F-SEC-12 Appendix A and F-SEC-12 Appendix B.

**F-SEC-13**

**REF: Ex. F-2, p.7-8**

Please explain what parameters PowerStream used in selecting the distributors to compare itself to in Figures 2-4.

**RESPONSE:**

Please see response to F-Energy Probe-10.

**F-SEC-14**

**REF: Ex. F-2, p.5**

For each third-party review, please provide copies of their reports.

**RESPONSE:**

There are no third-party reviews of the Peer-to-Peer Benchmarking information provided in this rate proposal.

This information was compiled by PowerStream from data available from the Ontario Energy Board website.

The cost comparisons provided in this section were taken from the Ontario Energy Board's 2013 Yearbook of Electricity Distributors. It can be found at: http://www.ontarioenergyboard.ca/oeb/_Documents/RRR/2013_Yearbook_of_Electricity_Distributors.pdf

**F-VECC-5**

**REF: F-G/T-1pg. 3/Table 1**

a) Table 1 appears to calculate the expected productivity savings to be attained on the base 2013 year. Please recalculate the table showing what savings would be required if the 0.3% stretch factor were calculated on each years preceding value.

**RESPONSE:**

a) The requested information is presented in Table F-VECC-5-1 below.

**Table F-VECC-5-1: Alternative Calculation of Expected Productivity Savings ($ Millions)**

| **Productivity Savings Expected** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **Total** |
|---|---|---|---|---|---|---|---|---|
| Added in 2014 | $ 0.46 | $ 0.46 | $ 0.46 | $ 0.46 | $ 0.46 | $ 0.46 | $ 0.46 | $ 3.24 |
| Added in 2015 | | $ 0.47 | $ 0.47 | $ 0.47 | $ 0.47 | $ 0.47 | $ 0.47 | $ 2.81 |
| Added in 2016 | | | $ 0.48 | $ 0.48 | $ 0.48 | $ 0.48 | $ 0.48 | $ 2.38 |
| Added in 2017 | | | | $ 0.48 | $ 0.48 | $ 0.48 | $ 0.48 | $ 1.93 |
| Added in 2018 | | | | | $ 0.49 | $ 0.49 | $ 0.49 | $ 1.46 |
| Added in 2019 | | | | | | $ 0.49 | $ 0.49 | $ 0.99 |
| Added in 2020 | | | | | | | $ 0.50 | $ 0.50 |
| **Total** | **$ 0.46** | **$ 0.93** | **$ 1.41** | **$ 1.89** | **$ 2.38** | **$ 2.87** | **$ 3.37** | **$ 13.31** |
| **Based on:** | | | | | | | | |
| Prior Year Revenue Requirement: | $154.2 | $ 156.4 | $ 158.4 | $ 160.5 | $ 162.5 | $ 164.6 | $ 166.8 | |
| Actual / estimated IPI-X | 1.40% | 1.30% | 1.30% | 1.30% | 1.30% | 1.30% | 1.30% | |
| Annual savings requirement: | 0.30% | 0.30% | 0.30% | 0.30% | 0.30% | 0.30% | 0.30% | |
| X Factor amount | $ 0.46 | $ 0.47 | $ 0.48 | $ 0.48 | $ 0.49 | $ 0.49 | $ 0.50 | |

**F-VECC-6**

**REF: F-G/T-1pg. 6/Table 6 & J/T-1/pg.4**

Pre-amble: It is unclear how PowerStream defines "*incremental new costs for changing requirement*." Most, if not all the items shown in the table appear not to be costs related to incremental new responsibilities, as for example might have occurred as part of the introduction of TOU metered services. Rather they appear to be "business as usual" costs, albeit at increased amounts as compared to past spending.

a) Please provide the definition used for classifying costs into Table 6.
b) For each category in Table 6 (e.g. vegetation management) please show the amount that was approved as part of the last Board cost of service application (e.g. 2013).
c) Please provide details as to what activities are captured under the categories of "Risk Management" and "Customer expectation".
d) Please explain why for many of the categories the amounts are larger in the early years and decline or are negative in subsequent years.
e) Why is the replacement of the CIS classified as both a continuous productivity improvement and also as an incremental new cost?

**RESPONSE:**

a) PowerStream assessed its cost drivers based on significant changes year over year. The year over year variances were classified into categories based on changes in corporate strategy, changes in business operations or material increases that impact the business on an ongoing basis. For example, PowerStream changed its policy in regards to vegetation management and system hardening which increased OM&A and therefore was considered a cost driver.

b) The 2013 Board Approved costs per cost driver is included in the table below:

| Total Costs ($ 000's) | 2013 Board Approved Budget |
|---|---|
| New CIS incremental costs * | $0 |
| Vegetation management | $1,398 |
| Compliance | $1,418 |
| Risk Management | $2,786 |
| Customer expectation | $2,246 |
| **Total** | **$7,848** |

* - New post 2013, hence no budget

c) Risk Management activities include costs associated with the following:

- Pre-hiring for engineering and apprentice programs to ensure appropriate business continuity and succession planning.
- Headcount for specialized positions to manage risks and seize opportunities related to the achievement of PowerStream's Corporate Objectives. For example, an Emergency Preparedness Manager and Health and Safety Trainer, and

Customer Expectation includes:

- Activities to enhance the customer service experience. For example, consulting costs are incurred for language services related to the translation of calls and interactions with customers.
- Enhanced Call Centre activities to ensure customers are better informed during outages, and
- Consulting costs to engage customers for input in the development of the Distribution Plan.

d) Many categories have larger amounts in early years as many initiatives have significant up-front costs. For example one of the main drivers of costs in 2014 – 2015 relates to the CIS Implementation that has a go live date of Q2 2015. There are significant increases in costs in preparation for the system cut-over activities such as training and the engagement of an application managed services provider that can support the new CIS system. In addition, there were Compliance and Customer Expectation costs increases in the period 2014 – 2015, relating to the implementation of initiatives around customer engagement. A number of studies and surveys were conducted which increased costs during those years to satisfy the RRFE Report by the OEB to engage customers for input in the development of the Distribution Plan. Risk Management also relates to timing due to pre-hiring engineering and apprentice programs to ensure appropriate business continuity and succession planning due to retirements of an aging work force from 2014 – 2018.

e) The replacement of the CIS is included as an incremental new OM&A cost as a result of the maintenance and training costs associated with this new system. The new CIS is also classified as continuous improvement due to the long term productivity efficiencies that will be gained as a result of using the new software.

**F-VECC-7**

**REF: Ex. F/T-2/pg.3 & Appendix 2-L**

a) Please explain how the degradation in labour productivity as measured by OM&A costs per FTE (going from $150/FTE in 2013 to $185/FTE in 2020) is congruent with the proposition of PowerStream that there are productivity savings with the proposed rate plan.
b) Please confirm that no total factor productivity study, capital cost benchmarking study or an overall OM&A benchmarking study has been completed in support of the rate proposal.
c) Please confirm that under the proposal PowerStream is predicting a decline in its productivity as measured by the predicted vs actual/forecast costs (as shown in Figure 1).

**RESPONSE**:

a) The OM&A costs per FTE metric in a given period is the result of changes in OM&A costs and changes in FTEs. Changes in OM&A costs are a function of a number of factors, such as labour cost increases arising from additional labour to serve an increasing customer base, from salary progression, from non-labour cost increases and from changes in the various programs and activities. These and other factors are discussed in Appendix J. As shown in Appendix 2-L, increases in the OM&A per FTE metric have been occurring for the period prior to the term of the proposed rate plan and continue during the rate plan. Increases in the OM&A per FTE, both historically and for the rate plan, is not incompatible with achievement of productivity savings. The proper assessment is not whether the OM&A per FTE metric shows "degradation"; such "degradation" is an expected occurrence for a utility with a growing customer base. Rather, the proper assessment is whether the degree of "degradation" is appropriate. In that regard, PowerStream has estimated in Table 3 of Exhibit F, Tab1 and as updated in the response to F-SEC-6 that it will have achieved $15.8 million in productivity savings from 2014 to 2020, $13.8 million of which pertain to the proposed 5-year rate plan. These productivity savings exceed the OEB Expected Savings of $11.6 million for the 5-year period.

b) PowerStream's evidence on Benchmarking is contained in Exhibit F, Tab 2. It consists of the Predicted Cost model benchmarking, based on the PEG model used by the Board, and Peer-to-Peer Benchmarking. No other total factor productivity study, capital cost benchmarking study or an overall OM&A benchmarking study has been undertaken.

c) PowerStream confirms that the Predicted Cost model shows an increase in actual/forecasted costs relative to the predicted costs from the Predicted Cost model but reiterates that there are a number of factors, as set out in Exhibit F, Tab 2 that must be considered before drawing hard conclusions regarding such comparison.

**F-VECC-8**

**REF: Ex. F/T-2/pg.4-6**

a) At the above reference PowerStream lists a number of factors which it postulates makes it different (and hence non-comparable in some aspect) to other Ontario distributors. What study has the PowerStream undertaken to understand what difference exist between its operations and that of other Utilities?

b) Has PowerStream undertaken any similar studies of the working capital requirements of other bi-monthly billing utilities?

**RESPONSE:**

a) PowerStream has not undertaken studies of other utilities. The comments are based on PowerStream's general knowledge concerning the industry.

The primary difference is the level of capital spending required to upgrade existing assets. The fact that there are differing capital investment requirements among distributors is discussed in the RRFE and is the basis for the differing rate methods: 4th Generation IR, Custom IR and Annual Index. This is evidenced by the fact that all of these rate methods are being selected by distributors.

b) PowerStream has not undertaken any studies of the working capital requirements of other bi-monthly billing utilities.

**F-VECC-9**

**REF: Ex. F/T2/pg.6**

a) Please revise Table 2 (OM&A per customer comparison) removing Toronto Hydro and Hydro One.

**RESPONSE:**

a) Table F-VECC-9-1 compares PowerStream's OM&A per customer with the remaining 70 other Ontario Electric Distributors in the OEB 2013 yearbook after removal of Hydro One Networks Inc. and Toronto Hydro.

**Table F-VECC-9-1: OM&A per Customer from 2013 Yearbook (Excluding Hydro One Networks Inc. and Toronto Hydro)**

| | OM&A Per Customer | OM&A Rank |
|---|---|---|
| PowerStream Inc. | $ 234.24 | 13 |
| Average | $ 313.60 | 74.7% |
| Median | $ 276.34 | 84.8% |

Note: % represent PowerStream's cost as a % of the average and mean cost respectively.

**F-VECC-10**

**REF: Ex. G/T2/Appendix G-2-1 Consolidated DSP/T2/pg.2**

a) With respect to the Customer Consultation what was the number of residential customers who participated?
b) How was it determined that these residential customers represented a random sample of the population of customers (for example, employment status, age, demographic, etc.)
c) What tests were used understand whether the participating group results could be extrapolated to the general population of PowerStream customers?

**RESPONSE:**

a) Three of the five components of PowerStream's Customer Consultation included residential participants and respondents. The residential consultation had both a qualitative element to collect the range of views of PowerStream's residential customers and a quantitative element to understand the distribution of those views across residential customers.

The qualitative elements included:

1. A voluntary online primer completed by 1,521 residential customers; and
2. Four randomly-recruited consumer consultation groups including 23 residential customers.

The quantitative element consisted of:

3. A residential telephone survey of 1,001 consumers randomly recruited from a stratified sample.

b) Each of PowerStream's three residential consumer engagement approaches are addressed separately below, as each engagement followed a different methodological approach:

**Online Primer**: As noted above, the online primer was part of the qualitative phase of the customer engagement. The purpose of qualitative elements is to collect the range of views that exist within a population, not to project results across a population. As a qualitative exercise, no attempts were made to weight the responses of volunteered customers to reflect that of PowerStream's actual customer population.

As indicated in the Customer Consultation (see **E-G/T2/Appendix G-2-1 Consolidated DSP/T2/pg. 4**), "*readers are cautioned that the online primer results represent the views* *of volunteers*." The online primer sample is not randomly selected and cannot be generalised to the broader public. However, you should consider that these customers cared enough about the distribution system to share their time and their opinions.

While the results are not statistically significant, the consumer feedback obtained from the online primer was used to inform the design of the residential telephone survey.

**Residential Customer Consultation (Focus Groups)**: Again, as noted above, the online primer was part of the qualitative phase of the customer engagement. The purpose of qualitative elements is to collect the range of views that exist within a population, not to project results across a population.

While the results are qualitative, a random digit dialing methodology was used to recruit focus group participants to ensure that all types of consumer had an opportunity to participate in the qualitative stage and not just the consumers most likely to volunteer. The criteria to qualify as a participant for the residential focus groups required participants to be primary electricity bill payer in their household. While participants observably came from diverse demographic backgrounds, quotas were not set in the recruitment of participants.

While the results are not statistically significant, the consumer feedback obtained from the online primer was used to inform the design of the residential telephone survey.

**Residential Telephone Survey**: The residential telephone survey was based on a random sample which can reliably project the incidence to the broader population of PowerStream customers.

The survey followed a stratified random sampling methodology. This is a method of sampling that divides the population into smaller groups known as strata. In stratified random sampling, the strata are formed based on members' shared attributes or characteristics (in this case, service territory and household electricity consumption).

In this survey, residential customers were divided into strata based on service territory populations and then again into quartiles based on annual electricity consumption to ensure the sample has a proportionate mix of customers from low, medium-low, medium-high, and high electricity usage households.

A random sample from each stratum was taken in a number proportional to the stratum's size when compared to the customer population. These subsets of the strata are then pooled to form a random sample.

The table below illustrates the strata divisions for the Residential customer survey:

| Residential Customers | Count | % Dist | Sample | Quartile 1 | Quartile 2 | Quartile 3 | Quartile 4 |
|---|---|---|---|---|---|---|---|
| **Aurora** | 16,673 | 5% | 53 | 13 | 13 | 13 | 13 |
| **Barrie** | 47,194 | 15% | 151 | 38 | 38 | 38 | 38 |
| **Bradford** | 7,896 | 3% | 25 | 6 | 6 | 6 | 6 |
| **Markham** | 87,074 | 28% | 279 | 70 | 70 | 70 | 70 |
| **Richmond Hill** | 54,006 | 17% | 173 | 43 | 43 | 43 | 43 |
| **Vaughan** | 81,528 | 26% | 262 | 65 | 65 | 65 | 65 |
| **Other** | 17,285 | 6% | 55 | 14 | 14 | 14 | 14 |
| **Total** | **311,656** | **100%** | **1,000** | **250** | **250** | **250** | **250** |

c) As noted earlier, the residential consultation had both a qualitative element to collect the range of views of PowerStream's residential customers and a quantitative element to understand the distribution of those views across residential customers.

It is not appropriate to extrapolate the result of the qualitative findings (online primer *or* residential focus groups) to the general population of PowerStream customer-base.

As we noted in **VECC-10 (b)**, the sample was generated using a stratified random sample approach. It is important to remember this is NOT a general public survey, it is a customer survey. Since the strata were based on rate class, region and usage, no weights are required because we end up with the exactly correct proportions for region and usage. Since there is no definitive information about other customer characteristics, no tests of variance are required.

**F-VECC-11**

**REF: Ex. G/T2/Appendix G-2-1 Consolidated DSP/T2/pg.104**

a) What was the non-response rate of the telephone survey?
b) What checks were made to test for non-response bias?

**RESPONSE:**

a) During the survey field window, over 10,000 unique residential telephone numbers were called (approximate 5% of the residential customers in PowerStream's service territory).

Before a randomly selected telephone number is retired from the sample database, 8 attempts to reach potential respondents at each unique telephone number were made OR until an interviewer received a hard refusal.

- **Contact Rate** (percentage of households in which the primary electricity bill payer was reached): 45% (4,940/10,985)
- **Cooperation Rate** (percentage of households reached which yielded a completed interview): 20% (1,001/4,940)
- **Response Rate** (percentage of all working numbers which yielded a completed interview): 9% (1,001/10,985)
  [*Contact Rate* x *Cooperation Rate*]

b) A non-response bias occurs in a survey if the answers of respondents differ from that of the potential answers of those who did not answer. In more technical terms, what matters is whether the propensity to respond to the survey is correlated with the propensity to give a particular answer to a question.

This means that in some cases there may be a *non-response bias* if the response rate is low. However, a low response rate in and of itself does not create nonresponse bias in survey estimates if there is no correlation between response propensity and opinion.

Efforts were made to reduce non-response bias in the telephone survey estimates by employing a stratified random sampling methodology based on the known population of household energy consumption by regions within PowerStream's service territory. If you refer to **E-G/T2/Appendix G-2-1 Consolidated DSP/T2/pg. 105** you will see that the stratified sampling approach delivered exactly the correct proportions of customers based on the known characteristics of region and electricity usage.

We do not have data on the demographics of the entire population of residential consumers so it is not possible to test for representativeness on other measures. For information purposes, we have also provided information on the demographic profile of residential survey respondents (**see E-G/T2/Appendix G-2-1 Consolidated DSP/T2/pg. 106**).

# EXHIBIT G: RATE BASE

## G-AMPCO-4

**REF: Ex. G-Tab 2-5.0 Introduction Page 3 Table 1**

a) Please provide a table that shows the Annual Dollar Spending and Annual Percentage Spending by OEB Category and Grand Total for the years 2009 to 2014.

**RESPONSE:**

a) Due to the merger of PowerStream with Barrie Hydro Distribution Inc. in 2009, and the differences in financial reporting methods, PowerStream is unable to provide meaningful 2009-2010 historical costs.

The annual capital expenditures by investment category are shown below in Table 1, Section 5.4.1 page 2 of 11. The table outlining the percentages is shown below.

| | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|
| | Actual | Actual | Actual | Actual |
| General Plant | 12% | 32% | 21% | 24% |
| System Access | 33% | 27% | 18% | 24% |
| System Renewal | 18% | 23% | 24% | 36% |
| System Service | 36% | 18% | 37% | 16% |
| Grand Total | 100% | 100% | 100% | 100% |

## G-AMPCO-5

**REF: Ex. G-Tab 2-5.2.1 Distribution System Plan Overview, Page 5, Third Party Reviews**

a) By category and consultant, please indicate:
- the Title and date of each consultant report and whether or not copies of each report have been included in PowerStream's filing
- Whether an RFP was issued or the work was sole-sourced
- The value of each consultant's work

b) Please provide copies of all reports not included in the application.

## RESPONSE:

a) Table 1 indicates the responses to the requested information. None of these reports were included in the DS Plan.

| Category | Date Written | Title of Report | RFP or Sole Source | Value of Contract | Included in DS Plan | Consultant | Section Reference | Driver |
|---|---|---|---|---|---|---|---|---|
| Asset Condition Assessment | 2007/2008 | Power Tranformer Assessment, Assessment of Circuit Breakers, Primary Cable, MS Transformers Asset Condition & Risk Assessment | RFP | $120,000 | no | Kinectrics | 5.3.3 | Initial report and base models |
| Storm Hardening | Fall 2014 | Hardening the Distribution System against severe storms | RFP | $80,000 | no | CIMA | 5.2.3 | review weather patterns & other utilty experence, review Powerstream practices and make recommendations. |
| Asset Management | Winter 2013 | Asset Management Program Assessment (PAS 55) | sole source | $28,000 | no | UMS | 5.3.3 | review current practices against PASS 55 |
| Customer Engagement | Winter 2015 | refer to Appendices C to F | sole source | $266,000 | yes | Innovative Solutions | 5.4.2 | fulfill requirements of Chapter 5 filing |
| Optimization & Prioritization | Spring 2014 | no title - vendor who supplied the system | RFP | not discrete | no | Copperleaf | 5.3.3 | develop benefit and risk mitigation value questions |
| Cyber Security | Winter 2012 | Independent CIP Controls Review | sole source | $9,300 | no | White Hat | 5.4.5 | perform cyber security audit and make recommendations |
| DS Plan | Winter 2015 | no title | sole source | not discrete | no | Paul Vlahos | all | review document and provide commentary |

b) Table 1: External Consultants and the DS Plan

| | |
|---|---|
| Asset Condition Assessment (Kinectrics) | G-AMPCO 5b Appendix A, B & C |
| Storm Hardening (CIMA) | G-SEC-19 Appendix D |
| Asset Management (UMS) | G-AMPCO 5b Appendix D |
| Customer Engagement | Included in DS Plan, Appendix C-F |
| Optimization & Prioritization | No report prepared |
| Cyber Security (WhiteHat) | G-AMPCO 5b Appendix E |
| DS Plan | Already provided |

**G-AMPCO-6**

**REF: Ex. G-Tab 2-5.2.3 Performance Measurement for Continuous Improvement**

a) Figure 1, Performance Metrics: Please discuss how the performance metrics were selected.

b) Figure 1, Performance Metrics: Please provide performance metrics that were considered and not selected and why.

c) Figure 1, Performance Metrics: Please provide the annual targets for each metric.

d) Figure 1, Performance Metrics: Please discuss how these metrics relate to incentive pay for each employee group.

e) Please provide PowerStream's views on the following statement - Reliability Indices provide a better indication of distribution system performance when loss of supply, major event days and scheduled outages are excluded from the calculation.

f) DS Spending Progress Report Metric: Please explain how the success for this metric is measured.

g) DS Spending Progress Report Metric: Please provide PowerStream's historical capital spending compared to the approved capital budget for the years 2009 to 2014.

h) Work Order Closing Variances Metric: Please explain the how the success for this metric is measured.

i) Work Order Closing Variances Metric: Please discuss typical reasons for reviews issued that require and do not require management approval.

j) Cable Failure Rates Metric: Please explain why cable remediation is the only program where failure rate analysis can be readily measured.

k) Page 10 – 2013 and 2014 Extreme Weather Events: Please provide a copy of PowerStream's Internal Report that outlines lessons learned, key findings and 37 action items to enhance emergency restoration and communication efforts.

l) Pages 13-14, Figures 3 to 5: Please complete the following Table separately for Historical SAIFI, Historical SAIDI and Historical CAIDI in order to provide the indicated data values.

| | 2007 | 2008 | 2009 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|---|---|
| Total | | | | | | | |
| Excluding Loss of Supply (LOS) | | | | | | | |
| Excluding LOS and Major Event Days (MED) | | | | | | | |
| Excluding LOS, MED and Scheduled Outages (SO) | | | | | | | |

m) Pages 15-16, Figures 6 to 8: Please provide a list of the CEA utilities used to determine the CEA averages for SAIDI, SAIFI and CAIDI.

n) Pages 15-16, Figures 6 to 8: Please provide a table of the data values for each figure.

o) Page 16: The CEA numbers are all inclusive. On what basis are the PowerStream numbers provided?

p) Pages 15-16, Figures 6 to 8: Please reproduce Figures 6 to 8 to exclude Loss of Supply and Major Event Days and provide the data points.

q) Page 18: Please discuss PowerStream's approach in its 5 year plan to address SAIFI and the specific work programs that address SAIFI.

r) Page 18: Please discuss PowerStream's approach in its 5 year plan to address MAIFI and the specific work programs that address MAIFI.

s) Please complete the following Table to provide a breakdown of Controllable SAIDI related to defective equipment by year:

| | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|---|---|---|
| Defective Equipment | | | | | | | | |

t) Please reproduce the Table in part (u) to provide a breakdown of the causes of defective equipment.

u) Please identify the specific assets that are the leading cause of Customer Minutes of Interruption (CMI).

v) Please identify the specific assets that are the leading cause of Customer Interruptions.

**RESPONSE:**

a) The metrics were selected to align with existing reliability and internal key process metrics, to provide visibility to the success of the annual execution of the capital plan and the cumulative execution of the capital plan over 2016-2020

b) As indicated in F-SEC-11, PowerStream internally reports on five key processes and numerous sub-process measures.

Of these internally reported metrics, #4 was submitted into the DS Plan. Metric #5 was modified to detail the entire capital program (controllable and uncontrollable).

Metrics 1, 2, 3, 6, 7, 8 and 9 were not selected to be reported on. These were not included as DSP metrics as they are primarily geared to individual business unit's performance and not as inclusive as those selected to convey overall DS Plan execution.

c) Metric 1: remain, as a minimum, within the range of its historical previous 3 year average performance.

Metric 2: remain, as a minimum, within the range of its historical previous 3 year average performance.

Metric 3: remain, as a minimum, within the range of its historical previous 3 year average performance.

Metric 4: remain, as a minimum, within the range of its historical previous 3 year average performance.

Metric 5: +/- 10% from a 100% spend of the capital budget.

Metric 6: 50% in 2015 and increasing in subsequent years.

Metric 7: Significant improvement, with virtually no failures.

d) Depending on the role of the individual and business units, some management staff may have the execution of a metric as part of their individual performance incentive plan.

e) PowerStream measures its distribution system performance in accordance with OEB guidelines and generally accepted practices adopted by utilities across Canada following CEA methodologies. PowerStream believes there is value in examining both sets of metrics to enhance the understanding of system performance.

f) The DS Plan Spending Performance Metric found on page 2 of 19 in Section 5.2.3 of Exhibit G Tab 2 is measured by calculating the percent figure from taking the Total Actual Net Expenditures/Year and dividing by the Total Net Budget/Year. Success is determined by meeting the target as outlined in part c above.

g) Please refer to the table in PowerStream's IR response to G-AMPCO-12b.

h) Refer to Figure 2 Section 5.2.3, page 5 of 19. Success for the Work Order Closing Variance Metric is measured by achieving 50%, or higher, by month and yearly overall, for the percent of Work Orders Completed Within Variance (not requiring management approval). It is PowerStream's intention to increase from 50% on an annual basis.

i) Refer to G-SEC-16 b.

j) The cable remediation program can be readily measured from pre and post remediation. Typically the cable installed in a given area is of the same vintage, type and configuration. The failure rates for the cable segments in the area can be considered the same and hence the remediation efforts that lead to improvement can be easily measured. In contrast for other asset types (switchgear, as an example) as individual assets, the failure rate is impacted by other local factors such as contamination, type, location and system configuration which hampers a meaningful comparison.

k) Refer to G-SEC-19 Appendix A (internal report).

l)

| Year | PowerStream Total Excluding LOS | | | PowerStream Total Excluding LOS & MED | | | PowerStream Total Excluding LOS,MED, SO | | |
|---|---|---|---|---|---|---|---|---|---|
| | CAIDI | SAIFI | SAIDI | CAIDI | SAIFI | SAIDI | CAIDI | SAIFI | SAIDI |
| 2007 | 1.168 | 1.801 | 2.105 | 0.75 | 1.5 | 1.125 | 0.732 | 1.479 | 1.083 |
| 2008 | 0.968 | 1.148 | 1.112 | 0.968 | 1.148 | 1.112 | 0.884 | 1.089 | 0.963 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 2009 | 1.484 | 1.068 | 1.585 | 1.12 | 0.873 | 0.978 | 1.034 | 0.842 | 0.87 |
| 2010 | 0.67 | 0.801 | 0.537 | 0.668 | 0.8 | 0.535 | 0.622 | 0.773 | 0.481 |
| 2011 | 1.043 | 1.003 | 1.046 | 1.051 | 0.959 | 1.008 | 1.028 | 0.914 | 0.94 |
| 2012 | 0.681 | 1.529 | 1.041 | 0.681 | 1.529 | 1.041 | 0.651 | 1.489 | 0.969 |
| 2013 | 4.368 | 2.237 | 9.771 | 0.881 | 1.309 | 1.153 | 0.811 | 1.266 | 1.028 |
| 2014 | 0.848 | 1.642 | 1.393 | 0.82 | 1.429 | 1.172 | 0.747 | 1.381 | 1.033 |

m)

The following is the list of the utilities that comprise the Urban Utilities.

City of Medicine Hat
City of Red Deer
Enersource Hydro Mississauga
ENMAX Power Corporation
EPCOR
Horizon Utilities
Hydro Ottawa
London Hydro
Oakville Hydro Electricity Distribution
Oshawa Power and Utilities Corporation
PowerStream Inc.
Saint John Energy
Saskatoon Light & Power
St. Thomas Energy
Toronto Hydro
*B.C. Hydro - Vancouver/Burnaby District
*B.C. Hydro - Victoria District
*Hydro One - Combined Urban Areas
*Hydro-Québec - Montréal Métropolitain
*Hydro-Québec - Québec Métropolitain
*Manitoba Hydro - Winnipeg
*Maritime Electric – Charlottetown Region
*NSPI - Halifax Urban
*NSPI - Provincial Urban Areas (excl. Halifax)

* refers to only a portion of their territory

n) Refer to G-SEC-20 b

o) PowerStream numbers are all inclusive.

p) PowerStream does not have the CEA data excluding LOS and MED and cannot provide a similar chart.

q) PowerStream's programs that are directed towards maintaining and reducing the SAIFI are as follows:

| |
|---|
| Worst Performing Feeders (WPF) |
| Inspection and Maintenance |
| Asset Replacement Programs |
| Storm Hardening |

These programs are described in the Consolidated DS Plan:

- Section 5.2.3 page 19 and 5.3.1 page 22 (Worst Performing Feeders);
- Section 5.3.1, page 18 (Inspection & Maintenance);
- Section 5.3.1, page 11 (Asset Condition Assessment and Replacement Programs) which include Cable Remediation, Switchgear Replacement, Transformer replacement, Mini-rupter replacement and Insulator replacement; and

Section 5.3.3, page 13 and 5.4.5, page 19 (Storm Hardening).

r) The five year plan includes capital programs that are geared towards reducing the SAIDI and SAIFI. In an indirect way the capital and maintenance programs help to reduce MAIFI (e.g. reduce the number of tree contacts, equipment failure). In addition PowerStream undertakes studies and complete projects to reduce MAIFI by:

1) Reviewing the protection for the feeder breakers; and

2) Reviewing the fuse coordination of the feeders.

s)

| **Defective Equipment Contributed SAIDI(min) by year** | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
| Defective Equipment | 28.46 | 20.07 | 26.45 | 14.28 | 30.63 | 30.48 | 35.68 | 29.13 |

t)

| Equipment Failure Causes | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Cause** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** |
| **Cable and Splice** | 70 | 75 | 75 | 81 | 103 | 123 | 133 | 113 |
| **Overhead Transformer** | 17 | 11 | 12 | 15 | 19 | 44 | 38 | 58 |
| **Underground Transformer** | 41 | 48 | 41 | 38 | 50 | 66 | 78 | 84 |
| **Arrestor** | 7 | 6 | 2 | 11 | 20 | 19 | 25 | 33 |
| **Line Hardware** | 19 | 17 | 18 | 5 | 16 | 36 | 33 | 52 |
| **Station Equipment** | 3 | 0 | 5 | 1 | 2 | 2 | 0 | 4 |
| **Switch** | 18 | 21 | 16 | 16 | 25 | 50 | 46 | 55 |
| **Termination** | 7 | 6 | 8 | 3 | 7 | 9 | 13 | 21 |
| **Elbow** | 19 | 9 | 11 | 19 | 20 | 21 | 33 | 31 |
| **Insulator** | 6 | 9 | 5 | 7 | 8 | 14 | 13 | 12 |
| **Switching Unit** | 16 | 21 | 20 | 15 | 30 | 24 | 28 | 15 |
| **Underground Transformer Vault** | | | | | | 12 | 11 | 4 |
| **Underground Transformer Submersible** | | | | | | 4 | 2 | 3 |
| **Station Equipment Breaker** | | | | | | 1 | 0 | 4 |
| **Switch LIS/Recloser** | | | | | | 3 | 0 | 5 |
| **Switch Manual LIS** | | | | | | 3 | 1 | 2 |
| **Elbow Arrestor** | | | | | | 2 | 0 | 1 |
| **Other** | 6 | 4 | 1 | 3 | 2 | 5 | 3 | 3 |

u) Top 5 Leading Asset Failure Causes contributing to CMI (2006-2014)

| **Failure Cause** |
|---|

| |
|---|
| 1. Cable and Splice |
| 2. Switching Unit |
| 3. Underground TX Padmount |
| 4. Line Hardware |
| 5. Arrestor |

v) Top 5 Leading Asset Failure Causes of Customer Interruptions (2006-2014)

| **Failure Cause** |
|---|
| 1. Cable and Splice |
| 2. Switching Unit |
| 3. Switch |
| 4. Arrestor |
| 5. Line Hardware |

## G-AMPCO-7

**REF: Ex. G-Tab 2-5.3.1 Asset Management Process Overview**

a) Pages 5 to 10: PowerStream describes its primary asset registers. Please discuss any existing significant issues and challenges related to the coordination and integration of the information provided by the key asset registers.

b) Please discuss if PowerStream foresees any significant issues or challenges using its key asset registers to track, coordinate and integrate the asset and project information related to its proposed project investments in the execution of its 5 year plan.

c) Page 21, Construction and Material Standards: PowerStream indicates that its construction standards have been approved by a provincially licensed professional engineer. Please discuss if this approval is done internally or externally. Please comment on how PowerStream's Construction and Material Standards compare to Industry Standards.

d) Page 22, Reliability Performance: PowerStream indicates it has committed to improve system reliability as part of the corporate "Strategic Direction – Five Year Critical Success Factors". Please confirm the Five Year Critical Success Factors and provide a reference.

e) Page 22: Reliability Performance: PowerStream indicates it will strive towards meeting the reliability target set for 2020. Please confirm the 2020 target.

f) Page 24, lines 26-30: Please confirm the capital budget threshold and how it is applied.

## RESPONSE:

a) There are no major integration issues with the current Asset Registers. PowerStream continues to improve integration and coordination as new technology becomes available and/or upgrades of current systems occur.

b) There are no anticipated major issues with Asset Registers in the future. PowerStream continues to improve integration and coordination as new technology becomes available and/or upgrades of current systems occur.

c) PowerStream's construction standards have been approved by a provincially licensed professional engineer who is a PowerStream employee. PowerStream's Construction and Material Standards are in compliance with Ontario Regulation 22/04 and CSA specifications and as such are comparable to Industry Standards.

d) **Health and Safety (Zero Serious Injuries)** - Achieve Zero serious injuries in each year until 2020.

**Employee Satisfaction (95% Level of Employee Satisfaction)** - Maintain an overall score of 95% on the combined average of the five key employee engagement on the Employee Survey and achieve 70% top box score (strongly agree)

**Business Excellence (Excellence Canada Order of Excellence Achievement)** - Achieve Order of Excellence status in Excellence Canada's Progressive Excellence Program based on external third party assessment.

**Customer Satisfaction**

a) 95% Level of Customer Satisfaction - Achieve an overall Customer Satisfaction score of 95%
b) Achieve an average of 40 Customer minutes of Interruption per customer per year
c) Reliability Centers of Focus - Defined sub-set of geographic areas that have reliability concerns based on outage history or sensitive loads where a specific improvement program is in place to ensure reliability performance is at least equal to or greater than the overall system wide average.

**Corporate Social Responsibility**

a) Reduce PowerStream's Environmental footprint
b) Meet or exceed mandated CDM targets

e) For the year 2020, the SAIDI Reliability Target for all outages excluding LOS/MED will be 59.97min based on an average weather pattern year. However, in the case of a year with severe weather, the upper limit threshold will be 81.07 min.

The following table outlines the expected reliability target for 2020:

| 2020 Reliability Target | |
|---|---|
| Upper Limit | = 81.07 min |
| **Target** | **= 59.97 min** |
| Lower Limit | = 45.41 min |

f) The capital budget threshold for 2016-2020 is as follows:

- 2016 - $132.9M
- 2017 - $131.6M
- 2018 - $125.5M
- 2019 - $125.5M
- 2020 - $125.5M

The Capital Budget Threshold is applied as a “cap” to the proposed yearly capital budget, as a financial constraint during optimization.

**G-AMPCO-8**

**REF 1: Ex. G-Tab 2-5.3.2 Overview of Assets Managed, Page 25**
**REF 2: Ex. G-Tab 2-5.3.3 Asset Lifecycle Optimization Policies and Procedures, Page 29**

a) The 2014 asset counts provided in Reference 1 differ from the 2014 asset counts provided at reference 2. Please reconcile.

**RESPONSE:**

a) The numbers identified in Table 10 were obtained earlier in the year (August 29, 2014). Since then, additional assets have been installed. The numbers identified in Figure 6 were obtained later (January 1, 2015). Thank you for pointing out the inconsistency with Table 10 that we missed. Figure 6 has the correct amounts.

**G-AMPCO-9**

**REF: Ex. G-Tab 2-5.3.2 Overview of Assets Managed**

a) Please complete the following table:

| Asset | Population | End of Life (years) | Population equal to or beyond End of Life at December 31, 2014 | % population equal to or beyond End of Life at December 31, 2014 |
|---|---|---|---|---|
| Power Transformers | | | | |
| Substation Power Transformers | | | | |
| Circuit Breakers | | | | |
| Transformer Station 230 kV Disconnect Switches | | | | |
| Substation Primary Disconnect Switches | | | | |
| Transformer Station Capacitor Banks | | | | |
| Station Reactors | | | | |
| Station Service Transformers (TS Stations) | | | | |
| Primary Metering Units (Transformer Stations) | | | | |
| Protection and Control Relays | | | | |
| Underground Cable | | | | |
| Distribution Transformers | | | | |
| Switchgear | | | | |
| Mini-Rupter Switches | | | | |
| Automated Switches | | | | |
| Wood Poles | | | | |

**RESPONSE:**

a) Please see the table below.

| Asset | Population | End of Life (Years) | Population Equal to or beyond End of Life at December 31, 2014 | % Population Equal to or beyond End of Life at December 31, 2014 |
|---|---|---|---|---|
| Transformer Station Power Transformers | 24 | 40 | 0 | 0 |
| Municipal Station Power Transformers | 72 | 40 | 18 | 25.0 |
| Transformer and Municipal Station Circuit Breakers | 398 | 40 | 41 | 10.3 |
| Transformer Station 230 kV Primary Switches | 22 | 40 | 0 | 0 |
| Municipal Station Primary Switches | 58 | 50 | 4 | 0.7 |
| Transformer Station Capacitor Banks | 9 | 30 | 0 | 0 |
| Transformer Station Reactors | 34 | 70 | 0 | 0 |
| TS Station Service Transformers | 20 | 45 | 0 | 0 |
| TS 230 kV Primary Metering Units | 18 combined<br>12 separate | 30 | 0 | 0 |
| TS P&C Relays - Electromechanical | 35 | 30 | 4 | 11.4 |
| TS P&C Relays - Solid State | 45 | 30 | 9 | 20 |
| TS P&C Relays - Microprocessor | 115 | 20 | 2 | 1.8 |
| Underground Cable | 8,137.5 (km) | 25 | 2,746 | 33.4 |
| Distribution Transformers | 44,192 | 40 | 777 | 1.8 |
| Switchgear | 1,847 | 30 | 182 | 10.0 |
| Mini-Rupter Switches | 433 | 30 | 73 | 16.9 |
| Automated Switches | 360 | 30 | 52 | 16.1 |
| Wood Poles | 38,070 | 45 | 3301 | 8.7 |

**G-AMPCO-10**

**REF: Ex. G-Tab 2-5.3.2 Overview of Assets Managed**

a) Pages 26 to 51: For each of the asset groups where PowerStream provided Health Indices, please provide the % of the population tested for each asset group.

**RESPONSE:**

a)

## Table G-AMPCO-10-1

**Asset Testing and Inspection**

| Asset Type | Testing and Inspection | % Inspected | Approximate % Tested per Year (1) |
|---|---|---|---|
| **TS Transformer** | Dissolved gas anlaysis (DGA) automatically performed every hour on TS transformers with 7-gas online monitoring units. Others monitor moisture, hydrogen and carbon monixide in real time. Annual oil samples sent to external lab for independant testing. Doble testing and Electrical testing performed every 4 years (or less if poor DGA conditions or a major event trigger a test). Tap changer unit maintenance performed every 4 years or if number of cyclic operations triggers a maintenance threshold. Transformer and associated ancilliary components are powerwashed twice a year, IR scanned twice a year, and painted approximately every 10 years. | 100% within a Year | 100% |
| **MS Transformer** | Oil analysis completed for all transformers annually. IR scanned twice a year. Painted approximately every 10 years. Online DGA equipment being installed on the entire fleet. | 100% within a Year | 100% |
| **Circuit Breakers/reclosers** | Monthly patrol inspection - Testing done every 4 years (includes cell/bus maintenance) or as triggered by cyclic operation. | 100% within a Year | 25% |
| **230 kV Switches** | Monthly patrol, (RCM) annual maintenance, (RCM) 5 year maintenance , (RCM)10 year maintenance , (RCM)15 year maintenance, (RCM) 20 year, (RCM) 25 year maintenance, Powerwashed twice a year, IR scanned twice a year | 100% within a Year | 100% |
| **MS Primary Switches** | Monthly patrol inspection - Maintenance done every 5 years (circuit switcher: monthly inspection, (RCM) 5, 10 and 15 year maintenance), IR scanned twice a year | 100% within a Year | 20% |
| **TS Capacitor Banks** | Monthly patrol inspection - Detailed visual inspection done annually, IR scanned twice a year | 100% within a Year | 100% |
| **TS Reactors** | Monthly patrol inspection - Testing done every 4 years, | 100% within a Year | 25% |
| **Station Service Transformers** | Monthly patrol inspection. No regularly scheduled testing. | 100% within a Year | No Testing Performed |
| **230 KV PMUs** | Monthly patrol inspection, 4 year detailed inspection - perfromed by station sustainment staff. IR scanned twice a year | 100% within a Year | 100% |
| **TS Relays (1)** | Monthly patrol. Lines, transformer and bus protections tested every 4 years. | 100% within a Year | 25% |
| **Distribution Transformer** | Inspection in 3-Year cycle (No testing) | 100% over 3 Years | No Testing Performed |
| **Switchgear** | Inspection in 3-Year cycle; Dry-Ice Cleaning in 6-year cycle (No testing). RTU tested for Automated gears - 17% | 100% over 3 Years; 100% Maintained over 6 Years | Manual Switchgear- No Testing Automated Switchgear- 17% |
| **Mini-Rupter** | Inspection in 3-Year cycle (No testing) | 100% over 3 Years | No Testing Performed |
| **Automated Switches** | Maintenance in 6 -Year cycle. RTU and Switch Testing | 17% in 2014 (Year 1) | 17% |
| **Poles** | Pole inspection and testing in 5-Year cycle | 100% over 5 Years | 20% |

# G-AMPCO-11

## REF: Ex. G-Tab 2-5.3.3 Asset Lifecycle Optimization Policies and Procedures

a) Page 10: Mini-Rupter Switch Replacement: Please provide a table that sets out the actual number of replacements per year and the spending for the years 2009 to 2014, and the planned number of replacements per year and the budget for the years 2015 to 2020.

b) Page 10: Automated Switch Replacement: Please provide a table that sets out the actual number of replacements per year and the spending for the years 2009 to 2014, and the planned number of replacements per year and the budget for the years 2015 to 2020.

c) Page 12: Fault Indicator Replacement: Please provide a table that sets out the actual number of replacements per year and the spending for the years 2009 to 2014, and the planned number of replacements per year and the budget for the years 2015 to 2020.

d) Page 12:-44 kV Porcelain Insulator Replacement: PowerStream is proposing to replace all of the remaining legacy 44 kV porcelain insulators with polymer type insulators over the next four years. Please provide the number of insulators to be replaced by year and the cost by year.

e) Page 19: Please provide PowerStream's Key Performance Indicator (KPI) Results (projected vs. actuals) for the years 2009 to 2014.

f) Page 26: Table 2 Annual O&M Spending: For each of the O&M costs listed in Table 2, please provide the frequency cycle that the activity is undertaken – for example annually, bi-annually, every 2 years etc.

g) Page 26: Table 2 Annual O&M Spending: For each of the O&M costs please provide the historical spending for the years 2009 to 2014.

h) Page 28, Vegetation Management: Please provide the analysis that underpins PowerStream's determination that the five year trimming cycle was not adequate to keep up with tree growth across the service territory and as such the tree trimming cycle has been adjusted to a three year cycle across the territory.

i) Page 28, Vegetation Management: Please provide a description of the work programs undertaken under vegetation management.

j) Page 28, Vegetation Management: Please discuss the size of the program and the km or number of trees to be addressed each year for the years 2015 to 2020 compared to the historical years 2009 to 2014.

k) Page 30: Please discuss further the trade off between capital investments and O&M costs and the premise that a renewed asset base should result in a decrease in O&M costs.

**RESPONSE:**

a) Due to the merger of PowerStream with Barrie Hydro Distribution Inc. in 2009, and the differences in financial reporting methods, PowerStream is unable to provide meaningful 2009-2010 historical costs and asset quantities. This applies for all subsequent questions.

**Mini-Rupter Switch Actual Replacement 2011 - 2014**

| | Actual data | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Year | 2011 | | 2012 | | 2013 | | 2014 | |
| Classification | # of Units | $ | # of Units | $ | # of Units | $ | # of Units | $ |
| Mini-Rupter Replacement | - | - | - | - | - | - | 21 | 482,622 |

**Mini-Rupter Switch Planned Replacement 2015 - 2020**

| | Planned data | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | 2015 | | 2016 | | 2017 | | 2018 | | 2019 | | 2020 | |
| Classification | # of Units | $ | # of Units | $ | # of Units | $ | # of Units | $ | # of Units | $ | # of Units | $ |
| Mini-Rupter Replacement | 15 | 577,736 | 15 | 592,267 | 15 | 607,090 | 15 | 622,214 | 15 | 637,649 | 15 | 653,406 |

b)

**Automated Switch Actual Replacement 2011 - 2014**

| | Actual data | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Year | 2011 | | 2012 | | 2013 | | 2014 | |
| Classification | # of Units | $ | # of Units | $ | # of Units | $ | # of Units | $ |
| Automated Switch Replacement | - | - | - | - | 5 | 392,480 | 5 | 380,627 |

**Automated Switch Planned Replacement 2015 - 2020**

| | Planned data | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | 2015 | | 2016 | | 2017 | | 2018 | | 2019 | | 2020 | |
| Classification | # of Units | $ | # of Units | $ | # of Units | $ | # of Units | $ | # of Units | $ | # of Units | $ |
| Automated Switch Replacement | 5 | 435,912 | 5 | 447,130 | 5 | 458,595 | 5 | 470,301 | 5 | 482,308 | 5 | 494,628 |

c)

| Fault Indicator Actual Replacement 2011 - 2014 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Actual data | | | | | | | |
| Year | 2011 | | 2012 | | 2013 | | 2014 | |
| Classification | # of Units | $ | # of Units | $ | # of Units | $ | # of Units | $ |
| Fault Indicator | 779 | 46,173 | 1,171 | 326,565 | 1,940 | 527,405 | 1,547 | 484,511 |

| Fault Indicator Planned Replacement 2015 - 2020 | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Planned data | | | | | | | | | | | |
| Year | 2015 | | 2016 | | 2017 | | 2018 | | 2019 | | 2020 | |
| Classification | # of Units | $ | # of Units | $ | # of Units | $ | # of Units | $ | # of Units | $ | # of Units | $ |
| Fault Indicator | 1,650 | 500,000 | 1,650 | 500,000 | 1,650 | 500,000 | 1,650 | 500,000 | 1,650 | 500,000 | 1,650 | 500,000 |

d)

| Porcelain Insulator Planned Replacement 2015 - 2020 | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Planned data | | | | | | | | | | | |
| Year | 2015 | | 2016 | | 2017 | | 2018 | | 2019 | | 2020 | |
| Classification | # of Units | $ | # of Units | $ | # of Units | $ | # of Units | $ | # of Units | $ | # of Units | $ |
| Porcelain Insulators | 275 | 66,000 | 275 | 68,000 | 275 | 69,000 | 275 | 71,000 | 275 | 71,000 | 275 | 71,000 |

e) C55 Optimization commenced in 2014 and applied the KPI's as noted on a go forward basis.

f)

| Frequency Cycle for O&M Programs | | | |
|---|---|---|---|
| **Program** | | **Frequency** | **Comment** |
| Insulator Washing | | Bi-Annually | high priority areas - e.g. close to highways |
| Pole Testing | | 5 year | |
| Underground Cable Testing | | - | On selected potential candidates |
| Dry Ice Cleaning | | 6 year | |
| Infrared Scanning | | 3 year | |
| Overhead Switch Maintenance | | 6 year | |
| Vegetation Management | Rear Lot Area | 2 year | |
| | Urban Area | 3 year | |
| | Rural Area | 4 year | |

g) Please refer to the table below for the historical spending for years 2011-2014.

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|
| O & M COSTS | 2,242,034 | 2,438,036 | 2,522,976 | 2,627,108 | 3,290,425 | 3,824,791 | 4,364,492 | 4,909,270 | 5,459,443 | 6,014,538 |
| insulator washing | 85,013 | 88,166 | 98,335 | 99,615 | 140,000 | 141,400 | 142,814 | 144,242 | 145,684 | 147,142 |
| pole testing | 111,203 | 103,455 | 102,862 | 176,290 | 185,000 | 186,850 | 188,719 | 190,606 | 192,512 | 194,437 |
| underground cable testing | - | 14,722 | 10,047 | 9,957 | 51,945 | 53,177 | 54,431 | 55,506 | 56,521 | 57,417 |
| dry ice cleaning | 411,483 | 514,103 | 432,659 | 234,095 | 353,295 | 356,829 | 360,397 | 363,999 | 367,640 | 371,317 |
| infrared scanning | 100,600 | 201,285 | 143,700 | 122,125 | 146,856 | 148,516 | 150,193 | 151,841 | 153,490 | 155,104 |
| overhead switch maintenance | 348,929 | 288,497 | 274,342 | 225,361 | 353,329 | 357,419 | 361,532 | 365,606 | 369,752 | 373,528 |
| vegetation management | 1,184,805 | 1,227,810 | 1,461,031 | 1,759,666 | 2,060,000 | 2,580,600 | 3,106,406 | 3,637,470 | 4,173,844 | 4,715,593 |

h) Prior to 2012, in the PowerStream South service territories of Markham, Vaughan, Richmond Hill, and Aurora, vegetation management was undertaken on a 5-year cycle. However, this cycle proved less than effective, as in reality labour and financial resources were primarily focused on reactive activities such as addressing trouble spots and Worst Performing feeders. In the North service territories of Barrie and surrounding area, a 3-year cycle was in place and most activity was focused on maintaining the proactive 3-year cycle compared to reactive-type work.

In 2012, PowerStream reviewed its vegetation management program and concluded that the objectives of safety, customer service, and reliability would be better served with a consistent and proactive program across all service territories. The need for increased emphasis on proactive activity to maintain adequate clearances and reduce the probability of trees contacting power lines was further driven by increased storm activity, since the probability of tree contacts during storms is heightened. Practices of other LDCs were also surveyed. It was decided to establish a 3-year cycle across all PowerStream service territories, thereby implementing a more optimal cycle and harmonizing the practices across all predecessor utilities. This also facilitated better program management, as it was more effective to manage a consistent cycle across all territories rather than maintaining different practices in various areas.

i) Work activities undertaken under vegetation management are:

- Pruning of trees and removal of tree limbs to provide adequate clearance between power lines and trees. Cutbacks include allowance for growth up to the next clearing cycle;
- Pruning or removal of brush and undergrowth to provide adequate clearance from power lines;
- Removal of dead wood, broken limbs, and hangers;
- At property owner's request, pruning of limbs/brush of trees on private property to provide enough clearance from power lines so that the property owner's contractor can safely remove a tree;
- Limited removal of hazard or dead trees potentially detrimental to the power lines at request of Municipality;
- "Out of cycle" pruning of fast-growing trees or trouble spots identified during patrols or reports from the general public; and
- Emergency clearing during storms to assist with removing downed trees and limbs.

j) Prior to and including 2011, approximately 500 km of overhead line was addressed per annum under a 5-year vegetation management cycle. In 2012, PowerStream commenced working towards a 3-year cycle, and this was achieved fully in 2014, when approximately 840 km of overhead line was addressed. This will also be the approximate km addressed each year between 2015 and 2020.

k) PowerStream's philosophy is a measured and affordable approach to renewal that maintains a steady state asset age level. Contributions to this steady state asset age level include replacement of existing units, aging of existing units and additions of brand new units to the asset base. In addition, a substantive amount of the O&M costs are related to inspection of the assets and regular maintenance and not related to the age of the asset. For a more fulsome discussion, please refer to Section 5.3.3. Page 29.

**G-AMPCO-12**

**REF: Ex. G-Tab 2-5.4.1 Capital Expenditures Plan Summary**

a) Page 2 Table 1, Capital Expenditures by Investment Category: Please provide the historical Board Approved amounts by category and in total for the years prior to 2015.

b) Page 2 Table 1, Capital Expenditures by Investment Category: Please provide the historical budgeted amounts for the years 2009 to 2014 by category and in total.

**RESPONSE:**

a) In the December 21, 2012 Decision and Order in EB-2012-0161, the OEB accepted PowerStream's forecasted capital expenditures of $114,279,000 for the (2013) Test Year excepting a reduction of $2 million for capital contributions resulting in a net of $112,279,000. All other years, 2011, 2012, 2014, were IRM years, and therefore, do not have specific Board Approved amounts. The categorization names shown in Table 1 did not exist at the time of the Board's Decision and Order in EB-2012-0161.

b)

| | Historical | | | |
|---|---|---|---|---|
| | 2011 | 2012 | 2013 | 2014 |
| CATEGORY | Budget | Budget | Budget | Budget |
| Rate Base | $ '000 | $ '000 | $ '000 | $ '000 |
| System Access | 17,209 | 18,891 | 27,612 | 26,208 |
| System Renewal | 15,542 | 19,894 | 21,397 | 38,857 |
| System Service | 26,073 | 14,846 | 31,847 | 17,009 |
| General Plant | 10,906 | 23,055 | 31,128 | 26,165 |
| Grand Total | 69,731 | 76,685 | 111,984 | 108,238 |

**G-AMPCO-13**

**REF: Ex. G-Tab 2-5.4.2 Capital Expenditure Planning Process Overview**

a) Page 3, lines 11 to 12: The evidence indicates that early results show that 79% of customers are very or somewhat satisfied with their interaction with PowerStream. Please provide the percentage split between very and somewhat.

b) Page 3, line 19: The evidence indicates the key accounts team meet regularly with Large Users. Please provide the average number of meetings per year for the past three years with Large Users. Please provide the planned number of annual meetings for the 2015 to 2020 period.

c) Page 9, Rate Impacts: The evidence indicates that the proposed estimated bill impacts were presented for each rate class and generally the customers accepted the proposed rate increases. Please discuss how PowerStream provided the bill impact information i.e. was the information provided on a $ basis or a % basis? Was the bill impact information provided on a total bill basis?

**RESPONSE:**

a) The split for the Telephone Transactional results is:

- 58% very satisfied
- 21% somewhat satisfied

b) The target quantity of customer contacts for all Key Accounts customer engagement is four times per year. A contact is defined as telephone conversation, a face-to-face meeting, a site visit or an email. Key Accounts customers are visited once per year on average, unless supplementary visits are requested.

Over the past three years, the average number of Key Account customer contacts is between 2,500 to 3,000 total per year.

c) Bill impacts were presented to customers in both percentage and dollar amounts for each rate class (Residential, GS<50, GS>50 and Key Accounts). The proposed monthly increase was provided in dollars, and the average annual increase in percentage. Bill impacts were provided based on the average consumption per rate class. It was also explained that this proposed increase was on the distribution portion of the bill only and that other items on the bill may increase during this period.

E.g. Residential customers with an average consumption of 800 kWh per month pay approximately $27 for distribution charges. Over the next five years, customers will see an average increase of $2.14 per month or 7.7 per cent annually on the distribution rates charged by PowerStream

**G-AMPCO-14**

**REF: Ex. G-Tab 2-Appendix A: Project Investment Summaries, Cable Injection Program 2015-2020, Page 1**

Preamble: At Page 1, PowerStream indicates the annual cost will increase by 3% per year to account for general cost increase due to inflation and external cost.

a) Please provide the inflation assumptions by year for the years 2015 to 2020.

b) Please provide the external cost assumptions by year for the years 2015 to 2020 and explain the nature of these cost increases.

**RESPONSE:**

a) The inflation assumptions for Cable Injection 2015-2020 are as follows:

- External Contract: 3%/year, all years
- Material: 3%/year, all years
- Internal Labour: 2016 = 2.4%
  2017 = 2.4%
  2018 = 2.3%
  2019 = 2.3%
  2020 = 2.2%

b) Please see above for external cost assumptions. These are the expected costs increases based on historical cost increases from the US based vendor.

**G-AMPCO-15**

**REF: Ex. G-Tab 2-Appendix A: Project Investment Summaries**

a) System Renewal Programs: For each of the following projects, please provide the number of asset units (quantities) addressed for the years 2009 to 2020 by completing the following table.

| Project | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cable Injection Program (km) | | | | | | | | | | | | |
| Cable Replacement Program (km) | | | | | | | | | | | | |
| Emerging Cable Replacement (km) | | | | | | | | | | | | |
| Submersible Transformer Replacement | | | | | | | | | | | | |
| Switchgear Replacement | | | | | | | | | | | | |
| Pole Replacement | | | | | | | | | | | | |
| Pole Reinforcement | | | | | | | | | | | | |

**RESPONSE:**

a) Please see response to G-SEC-24.

## G-AMPCO-16

## REF: Ex. G-Tab 2-Appendix A: Project Investment Summaries

## Cable Injection Program; Cable Replacement Program

a) Please confirm when the Cable Injection Program and Cable Replacement Program commenced.

b) PowerStream indicates there were 103, 123, 133 and 113 cable and splice failures in 2011, 2012, 2013 and 2014 respectively. Please provide the cable and splice failures for the years 2006 to 2010.

c) Please confirm PowerStream's end of life of primary cable.

d) For the failures identified in part (b), please provide the number of failures by year on cables that were at or beyond end of life.

e) Please provide the historical expenditures for the Cable Injection Program and Cable Replacement Program for the years 2009 and 2010.

f) PowerStream indicates the Cable Replacement Program will stay stable for 22 years and then increase to higher levels from year 23 onward. Please discuss the increase in km and cost anticipated in year 23 and onward.

## RESPONSE:

a) The cable injection program commenced in 2011. The cable replacement program commenced in 2009.

b)

| Cause | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|
| **Cable and Splice** | 70 | 75 | 75 | 81 |

c) PowerStream's End of Life for primary cable is 25 years.

d) Due to the merger of PowerStream with Barrie Hydro Distribution Inc. in 2009 and the difference in recording the failure data, PowerStream is unable to provide the particular data set below prior to 2011.

| Cable and Splice failures on cables that were at or beyond End of Life | | | | |
|---|---|---|---|---|
| Year | 2011 | 2012 | 2013 | 2014 |
| Total Number of Cable/Splice Failures | 103 | 123 | 133 | 113 |
| Number of Cable/Splice Failures that were at or beyond End of Life (25 Years) | 53 | 72 | 89 | 64 |

e) Due to the merger of PowerStream with Barrie Hydro Distribution Inc in 2009, and the differences in financial reporting methods, PowerStream is unable to provide meaningful 2009-2010 historical costs.

f) Starting from year 23 (2037 onward), a large quantity of cable will be at end-of-life. At that time, since the only remediation option is cable replacement, and the cable replacement unit cost is much higher than that of cable injection, it is expected that the budget level will be higher to remediate the end of life cable.

The increase in km and cost anticipated in year 23 and onward is shown in the table below.

| Cable Remediation from year 23 onward | | | | | | |
|---|---|---|---|---|---|---|
| Year Range | 2037-2041 | 2042-2046 | 2047-2051 | 2052-2056 | 2057-2061 | 2062-2066 |
| Cable Remediation: Replacement (km) | 100 | 120 | 140 | 160 | 180 | 200 |
| Cost per year (in future $) | $83.2 M | $123.4 M | $166.0 M | $219.2 M | $285.0 M | $358.7 M |
| Cost per year (in 2016 $) | $42.1 M | $50.5 M | $59.0 M | $67.4 M | $75.8 M | $84.2 M |

**G-AMPCO-17**

**REF: Ex. G-Tab 2-Appendix A: Project Investment Summaries**

**Emerging Cable Replacement Program**

a) Please provide the historical expenditures for the years 2009 and 2010.

b) Please discuss why the majority of emerging cable faults occurs in industrial parks.

c) Please provide the failures by year for the years 2009 to 2014.

**RESPONSE:**

a) Due to the merger of PowerStream with Barrie Hydro Distribution Inc. in 2009, and the differences in financial reporting methods, PowerStream is unable to provide meaningful 2009-2010 historical costs.

b) Although the cable failures within PowerStream's Distribution System does not necessarily favor industrial areas over residential areas, the majority of emerging projects that are addressed by the Emerging Cable Replacement Program fall within industrial parks. Typically these are critical accounts that cannot tolerate the increased frequency of service interruptions due to a surge in cable faults. In this case, PowerStream is required to act quickly to minimize impact to the customer and restore service reliability back to acceptable levels.

c) The emerging cable failure data is not available as this is not tracked separately.

**G-AMPCO-18**

**REF: Ex. G-Tab 2-Appendix A: Project Investment Summaries**

**Submersible Transformer Replacement**

a) Please confirm the total population of submersible transformers.

b) Please confirm the year the Submersible Transformer Replacement Project commenced.

c) Please provide the historical expenditures prior to 2011.

d) Please provide the historical failure rates for submersible transformers for the years 2009 to 2014.

**RESPONSE:**

a) There are two types of submersible transformers – vault type and poletrans ("rocketship") type. The total population of these two types of submersible transformer is 109. There are twelve (12) remaining submersible transformers (rocketships) which are referred to in the 2015 replacement project. This project eliminates this type of transformer from the distribution system.

b) The submersible transformer replacement program commenced in 2009.

c) Due to the merger of PowerStream with Barrie Hydro Distribution Inc. in 2009, and the differences in financial reporting methods, PowerStream is unable to provide meaningful 2009-2010 historical costs.

d) Historical failures rates for submersible transformers for the years 2012 to 2014 are shown below. No failure information is available prior to 2011.

**Submersible Transformer Failure Rate**

| Year | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|
| Submersible TX Failed Units* | 0.47% | 1.91% | 1.48% | 2.75% |

*- Includes other submersible transformer

**G-AMPCO-19**

**REF: Ex. G-Tab 2-Appendix A: Project Investment Summaries**

**Switchgear Replacement Program**

a) Please provide a breakdown of the total population of switchgears by type of switchgear.

b) Please confirm the year the Switchgear Replacement Program commenced.

c) Please provide the historical spending for the years 2009 and 2010.

d) Page 1 – The evidence indicates an abstract of the ACA Technical Report on Distribution Switchgear at PowerStream is attached. Please provide the attachment and/or the reference.

e) There were 30, 24 and 28 switchgear failures in 2011, 2012 and 2013 respectively. Please provide the switchgear failures by year for the years 2006 to 2010, and for 2014.

f) Please confirm PowerStream's end of life for in-service switchgears by type of switchgear.

**RESPONSE:**

a) The breakdown of the total population of switchgear units by type of switchgear are shown in the table below.

| Type of Switchgear | | | | |
|---|---|---|---|---|
| **Type** | **Air** | **Oil** | **SF6** | **Solid Dielectric** |
| **# of Units** | **1,212** | **481** | **152** | **2** |

b) The Switchgear Replacement Program commenced in 2010.

c) Due to the merger of PowerStream with Barrie Hydro Distribution Inc. in 2009, and the differences in financial reporting methods, PowerStream is unable to provide meaningful 2009-2010 historical costs.

d) Refer to AMPCO 19d, Appendix D.

e) The number of failures for 2006 to 2010 and 2014 are shown in Appendix F, AMPCO 19 d. Figure 7.

f) PowerStream's End of Life for in-service switchgear units by type of switchgear is shown in the table below.

| Switchgear End of Life | | | |
|---|---|---|---|
| **Type** | **Air** | **Oil** | **SF6** |
| **End of Life Years** | **30** | **30** | **30** |

## G-AMPCO-20

## REF: Ex. G-Tab 2-Appendix A: Project Investment Summaries

### Storm Damage – Replacement of Distribution Equipment Due to Storm - South

a) Please provide the storm damage costs for 2009 and 2010.

b) Please provide the storm damage budget included in base rates.

c) Please provide the major asset quantities replaced by year for the years 2009 to 2014 and the corresponding costs associated with each asset group.

d) Please provide the rationale for the proposed spending levels for the years 2015 to 2020.

## RESPONSE:

a) Due to the merger of PowerStream with Barrie Hydro Distribution Inc. in 2009, and the differences in financial reporting methods, PowerStream is unable to provide meaningful 2009-2010 historical costs.

b) Base rates are interpreted to be that which is included in the capital plan. All of the storm damage budget is included in the capital plan.

c) Please refer to table below.

| | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|
| Storm Damage - Replacement of Distribution Equipment Due to Storm - **SOUTH** | | | | |
| # of Poles Replaced | 6 | 13 | 25 | 38 |
| Cost of Poles Replaced | $ 86,447 | $ 124,281 | $ 149,493 | $ 512,706 |
| # of Transformers | 23 | 13 | 19 | 16 |
| Cost of Transformers | $ 153,053 | $ 75,263 | $ 60,989 | $ 101,977 |
| Other Costs for Remaining Assets | $ 57,726 | $ 106,579 | $ 461,481 | $ 543,681 |

d) Please refer to G-SEC-26.

## G-AMPCO-21

## REF: Ex. G-Tab 2-Appendix A: Project Investment Summaries

### Storm Damage – Replacement of Distribution Equipment Due to Storm - North

a) Please provide the actual storm damage costs for 2009 and 2010.

b) Please provide the storm damage budget included in base rates.

c) Please provide the major asset quantities replaced by year for the years 2009 to 2014 and the corresponding costs associated with each asset group.

d) Please provide the rationale for the proposed spending levels for the years 2015 to 2020.

## RESPONSE:

a) Due to the merger of PowerStream with Barrie Hydro Distribution Inc. in 2009, and the differences in financial reporting methods, PowerStream is unable to provide meaningful 2009-2010 historical costs.

b) Base rates are interpreted to be that which is included in the capital plan. All of the storm damage budget is included in the capital plan.

c) Refer to table below.

| | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|
| Storm Damage - Replacement of Distribution Equipment Due to Storm - **NORTH** | | | | |
| # of Poles Replaced | 2 | 10 | 3 | 0 |
| Cost of Poles Replaced | $ 68,360 | $ 102,744 | $ 51,519 | $ 1,686 |
| # of Transformers | 2 | 6 | 0 | 0 |
| Cost of Transformers | $ 4,880 | $ 48,615 | $ - | $ - |
| Other Costs for Remaining Assets | $ 57,952 | $ 25,429 | $ 43,667 | $ - |

d) Refer to G-SEC-26.

**G-AMPCO-22**

**REF: Ex. G-Tab 2-Appendix A: Project Investment Summaries**

**Switchgears – Unscheduled Replacement of Failed Distribution Equipment - South**

a) Please provide the number of failed switchgears replaced by year for the years 2009 to 2014.

b) Please indicate the number of failed switchgear replaced by year that was not at or beyond end of life.

**RESPONSE:**

a) For the table below and part b, PowerStream has not provided data for 2009 and 2010. The data is difficult to obtain.

| Unscheduled failed switchgear replaced - South | | | | |
|---|---|---|---|---|
| Year | 2011 | 2012 | 2013 | 2014 |
| # of failed switchgear replaced | 30 | 22 | 28 | 15 |

b) Please refer to the table below.

| Unscheduled failed switchgear replaced that were not at or beyond end of life - South | | | | |
|---|---|---|---|---|
| Year | 2011 | 2012 | 2013 | 2014 |
| # of failed switchgear replaced that were not at or beyond end of life | 26 | 22 | 24 | 10 |

**G-AMPCO-23**

**REF: Ex. G-Tab 2-Appendix A: Project Investment Summaries**

**Switchgears – Unscheduled Replacement of Failed Distribution Equipment – North**

a) Please provide the number of failed switchgears replaced by year for the years 2009 to 2014.

b) Please indicate the number of failed switchgears replaced by year in part (a) that were not at or beyond end of life.

c) Please discuss the rational for the proposed spending levels for the years 2015 to 2020.

**RESPONSE:**

a) For the table below and part b, PowerStream has not provided data for 2009 and 2010. The data is difficult to obtain.

| Unscheduled failed switchgear replaced - North | | | | |
|---|---|---|---|---|
| Year | 2011 | 2012 | 2013 | 2014 |
| # of failed switchgear replaced | 0 | 2 | 0 | 0 |

b) Please refer to the table below.

| Unscheduled failed switchgear replaced that were not at or beyond end of life - North | | | | |
|---|---|---|---|---|
| Year | 2011 | 2012 | 2013 | 2014 |
| # of failed switchgear replaced that were not at or beyond end of life | 0 | 2 | 0 | 0 |

c) Please refer to PowerStream's IR response for G-SEC-26.

**G-AMPCO-24**

**REF: Ex. G-Tab 2-Appendix A: Project Investment Summaries**

**Unscheduled Replacement of Failed Equipment – Poles South**

a) Please provide the historical spending for the years 2009 and 2010.

b) Please provide the quantities of failed equipment by asset for the years 2009 to 2014.

**RESPONSE:**

a) Due to the merger of PowerStream with Barrie Hydro Distribution Inc. in 2009, and the differences in financial reporting methods, PowerStream is unable to provide meaningful 2009-2010 historical costs.

b) Please refer to table below.

| | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|
| Unscheduled Replacement of Failed Equipment - Poles etc - **SOUTH** | | | | |
| # of Poles Replaced | 43 | 48 | 33 | 24 |
| Cost of Poles Replaced | $ 502,335 | $ 467,681 | $ 329,761 | $ 349,341 |
| # of Transformers Replaced | 226 | 265 | 267 | 275 |
| Cost of Transformers Replaced | $ 2,162,872 | $ 2,367,548 | $ 2,497,114 | $ 2,154,729 |
| Other Costs for Remaining Assets | $ 2,807,329 | $ 936,304 | $ 1,224,185 | $ 1,653,501 |

**G-AMPCO-25**

**REF: Ex. G-Tab 2-Appendix A: Project Investment Summaries**

**Unscheduled Replacement of Failed Equipment – Poles North**

a) Please provide the historical spending for the years 2009 and 2010.

b) Please provide the quantities of failed equipment by asset for the years 2009 to 2014.

**RESPONSE:**

a) Due to the merger of PowerStream with Barrie Hydro Distribution Inc. in 2009, and the differences in financial reporting methods, PowerStream is unable to provide meaningful 2009-2010 historical costs.

b) Please refer to the table below.

| | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|
| Unscheduled Replacement of Failed Equipment - Poles etc - **NORTH** | | | | |
| # of Poles Replaced | 9 | 13 | 5 | 3 |
| Cost of Poles Replaced | $ 107,802 | $ 199,925 | $ 109,997 | $ 84,574 |
| # of Transformers Replaced | 78 | 111 | 79 | 71 |
| Cost of Transformers Replaced | $ 705,210 | $ 785,376 | $ 509,852 | $ 540,560 |
| Other Costs for Remaining Assets | $ 239,539 | $ 122,121 | $ 120,564 | $ 107,652 |

## G-AMPCO-26

## REF: Ex. G-Tab 2-Appendix A: Project Investment Summaries

## Pole Replacement Program

a) Please provide the in-service population of wood poles that are at end of life as at December 31, 2014 and confirm the end of life used by PowerStream for wood poles.

b) Please provide the historical spending for the years 2009 and 2010.

c) Please provide the annual failure rate for poles for the years 2009 to 2014.

d) Please provide the number of failed poles by year in part (e) that are not at or beyond end of life.

e) Please provide the number of concrete poles.

## RESPONSE:

a) There are 3,301 in-service wood poles that are equal to or beyond End of Life (EOL). EOL for wood poles at PowerStream is 45 years.

b) Due to the merger of PowerStream with Barrie Hydro Distribution Inc. in 2009, and the differences in financial reporting methods, PowerStream is unable to provide meaningful 2009-2010 historical costs.

c) The table below lists the annual failure rate of those poles that failed. PowerStream has not provided data for 2009. The data is difficult to obtain.

| Annual failure rate for poles | | | | | |
|---|---|---|---|---|---|
| Year | 2010 | 2011 | 2012 | 2013 | 2014 |
| Annual failure rate for poles | 0.005% | 0.008% | 0.008% | 0.039% | 0.063% |

d) There have been no failures of concrete poles that are not at or beyond EOL.

e) PowerStream owns 1,343 concrete poles.

**G-AMPCO-27**

**REF: Ex. G-Tab 2-Appendix A: Project Investment Summaries**

**Unforeseen Projects Initiated by PowerStream – North and South**

a) Please provide the historical expenditures for the years 2009 and 2010.

b) Please explain the increase in spending in 2013.

**RESPONSE:**

a) Due to the merger of PowerStream with Barrie Hydro Distribution Inc. in 2009, and the differences in financial reporting methods, PowerStream is unable to provide meaningful 2009-2010 historical costs.

b) The second quarter forecasted budget indicated a shortfall in planned spending for 2013. It was recognized that the shortfall projects would result in increased cost pressures in 2014. As such, it was decided that a number of high value 2014 distribution system projects would be advanced. PowerStream treated the advanced projects as Unforeseen Projects Initiated by PowerStream.

**G-AMPCO-28**

**REF: Ex. G-Tab 2-Appendix A: Project Investment Summaries**

**Storm Hardening and Rear Lot Supply – North and South**

a) Please provide the number of rear lot locations.

b) Please provide a breakdown of the proposed 2015 to 2020 budget between the three work programs: conversion of rear lot overhead, 4-circuit pole storm guying and in-line guying and relocation of flood sensitive equipment by year.

c) Please provide the number of rear lot conversions planned for each year for the period 2015 to 2020.

d) Please discuss when the conversion of rear lot project is expected to end.

**RESPONSE:**

a) PowerStream has 4,670 customers that are rear lot supplied. These customers are located in 35 rear lot geographic areas which are divided into 50 projects.

b) The breakdown of the proposed 2015 to 2020 budget between the three work programs: conversion of rear lot overhead, 4-circuit pole storm guying and in-line guying and relocation of flood sensitive equipment by year is shown in the table below.

**2015 - 2020 budget breakdown**

| Year | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|
| Conversion of rear lot overhead | $3,499,998 | $6,000,000 | $6,000,000 | $6,000,000 | $6,000,000 | $6,000,000 |
| 4-circuit pole storm guying and in-line guying | - | $1,650,017 | $1,799,752 | $1,174,834 | $600,540 | $1,200,071 |
| Relocation of flood sensitive equipment | - | $250,000 | $200,000 | $325,000 | $300,000 | - |
| Total | $3,499,998 | $7,900,017 | $7,999,752 | $7,499,834 | $6,900,540 | $7,200,071 |

c) The number of rear lot conversions planned for each year for the period 2015 to 2020 is shown in the table below.

| Conversion projects planned for 2015-2020 | | | | | | |
|---|---|---|---|---|---|---|
| Year | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
| # of Projects | 1 | 4 | 5 | 3 | 3 | 4 |
| # of Areas | 1 | 2 | 4 | 2 | 3 | 2 |

d) It is estimated that the rear lot program will end in 2029.

**G-CCC-44**

**REF: Ex. G/T1/p. 2**

Please identify the nature of the expenditures and the costs included in each year related to the Green Energy Act (those that would have been previously captured in deferral accounts.)

**RESPONSE:**

Tables G-CCC-44-1 and G-CCC-44-2 below provide a summary of the deferred renewable generation and smart grid projects as of December 31, 2014 plus 2015 to 2020 forecasted amounts. These amounts have been added to rate base based on the expected in-service dates of the projects.

**Table G-CCC-44-1: Renewable Generation Enabling Investments ($000)**

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | Total | Notes |
|---|---|---|---|---|---|---|---|---|---|
| WIMAX | $ 848.3 | $ - | $ - | $ - | $ - | $ - | $ - | $ 848.3 | 1 |
| Current Limiting Reactors | $ 221.0 | | | | | | | $ 221.0 | 2 |
| Stations Program | $ 37.8 | $ 81.4 | | | | | | $ 119.2 | 3 |
| CIS programming | $ 14.0 | | | | | | | $ 14.0 | 4 |
| TOTALS | $ 1,121.2 | $ 81.4 | $ - | $ - | $ - | $ - | $ - | $ 1,202.6 | |

***Notes:***

1. Build a WIMAX communications network for FIT generators to allow for remote trip and monitoring of FIT generators
2. Install in TS's fault reduction reactor to improve fault levels to accommodate FIT generation connections. Reduce the short circuit current to manageable levels
3. Install program feeder protections and fibre communication to accommodate generator transfer trip schemes at various Transformer stations
4. Update the customer information system to track and bill renewable generators.

**Table G-CCC-44-2: Smart Grid (SG) Expenditures ($000)**

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | Total | Notes |
|---|---|---|---|---|---|---|---|---|---|
| **Electric vehicles** | $ 39.9 | | | | | | | $ 39.9 | 1 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Digital fault indicators | $ 156.9 | $ 212.2 | | | | | | $ 369.1 | 2 |
| Geomagnetic induced Current ("GIC") | $ 40.4 | | | | | | | $ 40.4 | 3 |
| EV charging stations | $ 27.8 | $ 535.0 | | | | | | $ 562.8 | 4 |
| Smart Grid strategy | $ 58.5 | | | | | | | $ 58.5 | 5 |
| Micro grid | $ 1,166.7 | $ 176.6 | | | | | | $ 1,343.2 | 6 |
| Home Technologies and Green Button | $ 144.0 | | $ 703.5 | | | | | $ 847.5 | 7 |
| SG technology | $ 67.1 | $ 11.5 | $ 330.1 | | | | | $ 408.7 | 8 |
| Automatic feeder Restoration | $ 129.2 | $ 204.6 | | | | | | $ 333.8 | 9 |
| Storage Technologies | $ 1.1 | $ 423.5 | $ 160.5 | | | | | $ 585.1 | 10 |
| Analytics technologies | $ 1.9 | $ 267.5 | | | | | | $ 269.4 | 11 |
| TOTALS | $ 1,833.6 | $ 1,830.8 | $ 1,194.1 | | | | | $ 4,858.5 | |

***Notes***

1) Electric vehicles and related pilot testing to utilize power from the distribution grid. In 2013 to 2014 PS was investigating the application of V2H [ vehicle to home). Vehicles powering up homes.

2) PS successfully demonstrated the application of the Sensus Flexnet AMI system to deliver fault location, magnitude and other information to the control room. Additional application includes system performance relating to capacity and priortization.

3) PowerStream had successfully utilized GIC technology to detect solar induced current which was tripping transformers and causing outages. Advance notice to operators would avoid premature outages. Effectiveness being monitored by system operators.

4) PS is operating a Level III charger at our Cityview Head Office to identify the grid impact and customer usage patterns. Examples of learnings include the wide variation in actual amperage draw (independent of charger capacity) dependent on factors such as temperature and vehicle battery state-of-charge. In 2015, PowerStream will make any necessary upgrades and changes to this system as well as maintain operations.

5) PS has engaged various consultants to work with PS in developing an effective Smart grid strategy and plan including ongoing consultation with MOE to avoid duplicative work. Navigant has been one of the key partners in this work

6) PS is currently operating a demonstration micro grid including a control system to provide an automated system.

7) PowerStream is the LDC partner on the Rogers Ministry of Energy Smart Grid Fund Smart Home project. PS is supporting the introduction of energy management capabilities into the Rogers Smart Home offering. This will provide energy conservation and cost reduction to our customers. In addition, PS is a partner in the Energate Ministry of Energy Smart Grid Customer Opt-in dynamic pricing project. PS is currently introducing a voluntary residential dynamic pricing plan to residential customers whereby daily on-peak price varies in response to overall provincial demand. Shift consumption away from the more expensive on-peak price period to a lower price periods

8) PS is an observer LDC on the Opus OneMinistry of Energy Smart Grid Fund Distributed Generation Integration with Distributed Energy Management and Storage Network project. The experiences and observations from this project will be used in developing a Advanced Distribution Management Systems and Energy Management Systems.

9) Part of SG technology. Special hardware and software that support more effective feeder restoration.

10) Partnering with other companies to develop and pilot battery storage systems and other electrical storage systems as part of the smart grid

11) PS in partnership with our Operational Data Store vendor, has developed an advanced transformer loading tool that leverages our residential and commercial-industrial smart meter data. Access to detailed hour by hour transformer loading that can be used to optimize asset utilization and identify over and underloaded transformers. In 2015, PowerStream will update this tool to integrate into our new CIS system.

**G-CCC-45**

**REF: Ex. G/T2/p. 2**

The Capital Budget for the period 2016-2020 is increasing by 39% relative to the spending in the period 2011-2015. Please explain how PowerStream has the capacity to ramp up capital spending by this magnitude. What proportion of PowerStream's capital work is carried out using permanent staff and how much is carried out through contractors?

**RESPONSE:**

Notwithstanding any future plans to increase staffing, PowerStream plans to utilize contract resources for whatever work cannot be completed in-house. As identified in response to G-SEC-27 c, the proportion of capital work carried out using contractors is as shown in the table below:

| | Actual 2012 | Actual 2013 | Actual 2014 | Budget 2015 | Budget 2016 | Budget 2017 | Budget 2018 | Budget 2019 | Budget 2020 |
|---|---|---|---|---|---|---|---|---|---|
| **Contract / Consulting / Prof Serv** | 46,409,337 | 56,519,306 | 70,507,262 | 57,216,885 | 60,709,568 | 65,721,892 | 64,740,797 | 70,610,138 | 69,022,129 |
| **Total Capital Spend - Rate Based** | 74,915,000 | 93,500,000 | 109,488,127 | 118,399,999 | 132,800,017 | 131,499,752 | 125,399,834 | 125,400,540 | 125,400,071 |
| | | | | | | | | | |
| **% of Total** | 62% | 60% | 64% | 48% | 46% | 50% | 52% | 56% | 55% |
| | | | | | | | | | |

**G-CCC-46**

**REF: Ex. G/T2/p. 2**

Please explain why the capital budget amounts for 2018-2020 are the same. How were these budgets developed? How does PowerStream intend to manage the risk to ratepayers that the capital expenditures in each year may be less than the forecasts embedded in rates? Has Powerstream included efficiencies into these budgets? If so, please explain how.

**RESPONSE:**

The 2015-2020 budgets were developed in accordance with the Asset Management Process described in Exhibit G Tab 2 Section 5.3.1 pages 25-28, and optimized in accordance with Asset Lifecycle Optimization Policies and Procedures shown in Exhibit G Tab 2 Section 5.3.3 Pages 16 – 38. The finance department considers affordability and rate planning per Section 5.3.3 Page 18.

PowerStream will monitor the capital program in accordance with the DSP 5.2.3 metric 5, page 2. Please see the response to A-CCC-4

Refer to G-SEC-21 for efficiencies.

**G-CCC-47**

**REF: Ex. G/T2/p. 2**

What accounted for the significant jump in System Service expenditures in 2013?

**RESPONSE:**

As stated in Exhibit G, Tab 2, Section 5.4.4, page 8 of 14, "The large increase from 2012 of $21,010,055 was due to increased expenditures for cable replacement and cable injection projects and programs, increase expenditures in additional capacity lines projects (new feeders), increased expenditures for overhead lines projects, and increased expenditures for distribution automation." For more details on the historical expenditures in the cable projects and programs, please refer to the Historical/Planned tables and graphs for Project 100851 (Cable Replacement) and Project 100835 (Cable Injection) found in Exhibit G, Tab 2, Appendix A, pages 299-301, and 296-298, respectively.

**G-CCC-48**

**REF: Ex. G/T2/p. 2**

PowerStream is undertaking a significant amount of capital spending relative to historical levels during the term of the rate plan. How will ratepayers and the Board be able to assess whether the capital spend in each year was undertaken cost-effectively?

**RESPONSE:**

In setting just and reasonable rates, testing for prudence of past expenditures has always been and remains open to intervenors and the Board. Prudence reviews include not only whether an expenditure ought not to have been made but whether it was made cost-effectively. Prudence testing would be open for intervenors and the Board at the time of next of rebasing following this 5 year rate plan.

**G-CCC-49**

**REF: Ex. G/T3/p. 1**

Has PowerStream undertaken any internal analysis or external studies to determine whether or not the 13% Working Capital Analysis is appropriate for PowerStream? If so, please provide that analysis. If not, why not? What would be the impact on the test year revenue requirements if the WCA was reduced to 9%?

**RESPONSE:**

PowerStream has used the Board's default working capital allowance factor, currently 13%, in its rate applications including this one.

PowerStream feels that the Board's default WCA factor is reasonable and has not felt the need to do a lead lag study.

Table G-CCC-49-1 below shows the effect on the working capital allowance portion of rate base if the WCA Factor is changed from 13% to 9%.

**Table G-CCC-49-1: Effect of 9% Working Capital ("WC") Factor on Working Capital Allowance ($000)**

| | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|
| **WC Base:** | | | | | |
| Cost of Power | 1,103,218 | 1,111,266 | 1,158,754 | 1,184,080 | 1,203,134 |
| Distribution Expenses | 96,216 | 98,112 | 99,920 | 102,195 | 104,193 |
| **Working Capital Base** | **1,199,434** | **1,209,378** | **1,258,674** | **1,286,274** | **1,307,328** |
| **WC Allowance:** | | | | | |
| WC Allowance @ 13% | $ 155,926 | $ 157,219 | $ 163,628 | $ 167,216 | $ 169,953 |
| WC Allowance @ 9% | $ 107,949 | $ 108,844 | $ 113,281 | $ 115,765 | $ 117,660 |
| **WC Allowance Decrease** | **$ 47,977** | **$ 48,375** | **$ 50,347** | **$ 51,451** | **$ 52,293** |

Table G-CCC-49-2 below shows the impact of the rate base reduction, which equals the WC Allowance Decrease from Table G-CCC-49, on the revenue requirement for the 2016 to 2020 test years.

**Table G-CCC-49-2: WC Allowance Reduction Impact on Revenue Requirement**

| | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|
| Reduction in Rate Base | $ 47,977 | $ 48,375 | $ 50,347 | $ 51,451 | $ 52,293 |
| Return on Rate Base % | 6.02% | 6.08% | 6.10% | 6.10% | 6.10% |
| **Return on Rate Base $** | **$ 2,890** | **$ 2,943** | **$ 3,069** | **$ 3,136** | **$ 3,188** |
| Taxes[1] | $ 1,042 | $ 1,061 | $ 1,107 | $ 1,131 | $ 1,149 |
| **Decrease in Revenue Requirement** | **$ 3,932** | **$ 4,004** | **$ 4,176** | **$ 4,267** | **$ 4,337** |

1. Taxes are calculated as Return times 26.5% tax rates times 1/(1-0.265%) gross up factor.

## G-Energy Probe-11

## REF: Ex. G, Tab 1

Please update Table 1 to reflect actual data for 2014. If actual data for 2014 is not yet available, please update the table to reflect the most recent year-to-date actuals, along with the current estimate for the remainder of 2014.

**RESPONSE:**

Table 1 does reflect 2014 Actual data.

**G-Energy Probe-12**

**REF: Ex. G, Tab 2a and Appendix G-2a-1**

a) Please update Tables 2 and 3 to reflect actual data for 2014. If actual data for 2014 is not yet available, please update the table to reflect the most recent year-to-date actuals, along with the current estimate for the remainder of 2014.

b) Please update and provide a live Excel spreadsheet for Appendix G-2a-1 to reflect actual data for 2014. If actual data for 2014 is not yet available, please update the table to reflect the most recent year-to-date actuals, along with the current estimate for the remainder of 2014.

c) Does the 2015 capital expenditure and capital addition forecast represent the most current outlook for the bridge year? If not, please update all relevant tables and spreadsheets to reflect the most current forecast.

**RESPONSE:**

a) Tables 2 and 3 reflect 2014 actual data

b) Appendix G-2a-1 is 2014 Actual data.

c) Yes, the submitted forecast is the most current outlook for the 2015 bridge year.

**G-Energy Probe-13**

**REF: Ex. G, Appendix G-2a-1**

a) In each of the years shown, the disposals/adjustments for costs are significantly higher than for accumulated depreciation. Does this mean that the assets being disposed of are not fully depreciated? If not, please explain the difference between the two adjustments.

b) Please explain how the disposals for costs of $2,734 was estimated for 2016 and why this figure is unchanged in each of 2017 through 2020.

c) Please explain how the disposals for accumulated depreciation of $770 in 2016 and $829 in 2017 was estimated and why this latter figure is unchanged in each of

2018 through 2020.

**RESPONSE:**

a) Yes. Accidents, storm damage and other unplanned dispositions are common and often the cost of the asset exceeds the accumulative depreciation. In 2015 to 2020 there is also the removal of the GS>50 non interval meters that are required to be replaced by time of use meters in accordance with OEB notice of amendment EB-2013-0311. Most of these meters will not be fully depreciated at the time of removal from service.

b) In forecasting the 2015 to 2020 dispositions PowerStream used the actual history from 2012 and 2013 and calculated an average as a base. As there is a high degree of unpredictability regarding the dispositions in any one year it was decided that the average amounts would be used for all the test years.

c) In responding to this question, it was discovered that the estimated accumulated depreciation for dispositions was based on 2014 actuals rather than an average of the 2012 and 2013 actuals. In Table G-EP-13-1 below, the estimated accumulated depreciation for dispositions has been restated on a basis consistent with the estimated cost of dispositions. There should not be a difference between 2016 and the other test years.

**Table G-EP-13-1: Restated Accumulated Depreciation on Dispositions**

| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | Totals |
|---|---|---|---|---|---|---|---|
| **Restated** | | | | | | | |
| "Base" estimate | $ 129,844 | $ 129,844 | $ 129,844 | $ 129,844 | $ 129,844 | $ 129,844 | $ 779,065 |
| GS>50 meters | $ 330,258 | $ 587,858 | $ 587,858 | $ 87,858 | $ 87,858 | $ 587,858 | $ 3,269,550 |
| **Restated Total** | **$ 460,102** | **$ 717,703** | **$ 717,703** | **$ 717,703** | **$ 717,703** | **$ 717,703** | **$ 4,048,615** |
| Previous | $ 571,527 | $ 770,144 | $ 770,144 | $ 770,144 | $ 770,144 | $ 770,144 | $ 4,422,247 |
| **Change** | **-$ 111,425** | **-$ 52,441** | **-$ 52,441** | **-$ 52,441** | **-$ 52,441** | **-$ 52,441** | **-$ 373,632** |

PowerStream proposes to update the fixed asset amounts to reflect the lower restated amount of accumulated depreciation on dispositions shown in Table G-EP-13-1.

**G-Energy Probe-14**

**REF: Ex. G, Appendix G-2a-1**

a) For each of 2016 through 2020, please show the composition of the fully allocated depreciation (excluding non-distribution) between the amounts capitalized and the amount expensed.

b) Please confirm that the amounts expensed are included in the OM&A expenses. If this cannot be confirmed, please explain.

**RESPONSE:**

a) See Table G-EP-14-1 below for allocation of depreciation that goes into the burden pool.

**Table G-EP-14-1: Allocation of Depreciation in Burden Pool**

| **Deprecation Class** | **2016** | **2017** | **2018** | **2019** | **2020** |
|---|---|---|---|---|---|
| **Vehicle Depreciation** | | | | | |
| Allocation %: | | | | | |
| Capital | 74% | 74% | 74% | 74% | 74% |
| OM&A | 26% | 26% | 26% | 26% | 26% |
| Total Vehicle Alloc. | 100% | 100% | 100% | 100% | 100% |
| | | | | | |
| **Tools Depreciation** | | | | | |
| Allocation %: | | | | | |
| Capital | 37% | 37% | 37% | 37% | 37% |
| OM&A | 63% | 63% | 63% | 63% | 63% |
| Total Tools | 100% | 100% | 100% | 100% | 100% |

| | | | | | |
|---|---|---|---|---|---|
| Alloc. | | | | | |
| | | | | | |
| **Stores Depreciation** | | | | | |
| Allocation %: | | | | | |
| Capital | 97% | 97% | 97% | 97% | 97% |
| OM&A | 3% | 3% | 3% | 3% | 3% |
| Total Stores Alloc. | 100% | 100% | 100% | 100% | 100% |

b) PowerStream confirms that a portion of the fully allocated depreciation is allocated to OM&A as shown in our response to part (a) above. The OMA allocation is based primarily on the expected utilization of the underlying assets.

**G-Energy Probe-15**

**REF: Ex. G, Tab 2b & ICM True Up Model**

a) Please confirm that the figures shown for 2014 in the true up model are all actuals. If not, please update the model to reflect actual data for 2014.

b) Please confirm that all of the capital additions shown in the true model were placed into service in 2014 and were used or useful in that year. If this cannot be confirmed, please provide details.

c) Please explain why the incremental rate rider was not sufficient to cover the incremental capital costs despite the actual capital expenditures being lower than the forecast cost. In responding to this question, please provide a version of Sheet 6 (Incremental Capital Adjustment) that compares side by side the figures based on the actual expenditures and those used to derive the rate rider.

**RESPONSE:**

a) PowerStream confirms that the figures shown for 2014 in the ICM True up Model represent 2014 actual data.

b) PowerStream confirms that all of the capital additions shown in the ICM True up Model were placed into service in 2014 and were used or useful in that year.

c) Please note that PowerStream has updated the ICM True-up model to use unreduced CCA consistent with the 2014 ICM Workforms. The revised model is filed as G-Energy Probe-15 Appendix A.

As shown in Table G-EP-15-1 below, the updated true-up amount is a refund to customers of $22,097. PowerStream will correct this in the first update.

**Table G-EP-15-1: Incremental Capital Adjustment (ICM) True-up**

| | 2014 | 2015 | Total |
|---|---|---|---|
| ICM Incremental Revenue Requirement (from Sheet 6) | **$ 924,059** | **$ 924,059** | **$ 1,848,118** |
| Interest on Deferred and forecasted Amortization Expense (Sheet 8) | $ 2,543 | $ 7,629 | $ 10,172 |

| | | | | | | |
|---|---|---|---|---|---|---|
| ICM Funding Adder Revenues (from Sheet 7) | $ | 927,500 | $ | 928,000 | $ | 1,855,500 |
| ICM Funding Adder Interest (from Sheet 7) | $ | 5,000 | $ | 19,887 | $ | 24,887 |
| **Net Deferred Revenue Requirement** | **-$** | **5,898** | **-$** | **16,198** | **-$** | **22,097** |

Table G-EP-15-2 below compares the actual ICM revenue requirement calculation to the estimated ICM revenue requirement approved in PowerStream's 2014 IRM rate application.

# Table G-EP-15-2: Incremental Capital Adjustment (ICM) Actual vs. ICM Model

| | | | | | | 2014 IRM |
|---|---|---|---|---|---|---|
| **Return on Rate Base** | | | | | | |
| Incremental Capital CAPEX | | | $ 10,956,281 | B | | $ 11,326,840 |
| Depreciation Expense | | | $ 346,001 | C | | $ 260,582 |
| Incremental Capital CAPEX to be included in Rate Base | | | $ 10,610,281 | D = B - C | | $ 11,066,259 |
| Deemed ShortTerm Debt % | 4.0% | E | $ 424,411 | G = D * E | 4.0% | $ 442,650 |
| Deemed Long Term Debt % | 56.0% | F | $ 5,941,757 | H = D * F | 56.0% | $ 6,197,105 |
| Short Term Interest | 2.08% | I | $ 8,828 | K = G * I | 2.08% | $ 9,207 |
| Long Term Interest | 4.15% | J | $ 246,583 | L = H * J | 4.15% | $ 256,898 |
| Return on Rate Base - Interest | | | $ 255,411 | M = K + L | | $ 266,105 |
| Deemed Equity % | 40.0% | N | $ 4,244,112 | P = D * N | 40.0% | $ 4,426,503 |
| Return on Rate Base -Equity | 8.93% | O | $ 378,999 | Q = P * O | 8.93% | $ 395,287 |
| Return on Rate Base - Total | | | $ 634,410 | R = M + Q | | $ 661,392 |
| **Amortization Expense** | | | | | | |
| Amortization Expense - Incremental | | C | $ 346,001 | S | | $ 260,582 |
| **Grossed up PIL's** | | | | | | |
| Regulatory Taxable Income | | O | $ 378,999 | T | | $ 395,287 |
| Add Back Amortization Expense | | S | $ 346,001 | U | | $ 260,582 |
| Deduct CCA | | | $ 885,386 | V | | $ 906,147 |
| Incremental Taxable Income | | | -$ 160,386 | W = T + U - V | | -$ 250,279 |
| Current Tax Rate (F1.1 Z-Factor Tax Changes) | 26.0% | X | | | 26.0% | |
| PIL's Before Gross Up | | | -$ 41,700 | Y = W * X | | -$ 65,073 |
| Incremental Grossed Up PIL's | | | -$ 56,352 | Z = Y / ( 1 - X ) | | -$ 87,936 |
| **Ontario Capital Tax** | | | | | | |
| Incremental Capital CAPEX | | | $ 10,956,281 | AA | | $ 11,326,840 |
| Less : Available Capital Exemption (if any) | | | $ - | AB | | $ - |
| Incremental Capital CAPEX subject to OCT | | | $ 10,956,281 | AC = AA - AB | | $ 11,326,840 |
| Ontario Capital Tax Rate (F1.1 Z-Factor Tax Changes) | 0.000% | AD | | | | |
| Incremental Ontario Capital Tax | | | $ - | AE = AC * AD | | $ - |
| **Incremental Revenue Requirement** | | | | | | |
| Return on Rate Base - Total | | Q | $ 634,410 | AF | | $ 661,392 |
| Amortization Expense - Total | | S | $ 346,001 | AG | | $ 260,582 |
| Incremental Grossed Up PIL's | | Z | -$ 56,352 | AH | | -$ 87,936 |
| Incremental Ontario Capital Tax | | AE | $ - | AI | | $ - |
| Incremental Revenue Requirement | | | $ 924,059 | AJ = AF + AG + AH + AI | | $ 834,037 |

## G-Energy Probe-16

## REF: Ex. G, Tab 3

a) Does PowerStream bill all of its customers on a monthly basis?

b) If not, please provide, by rate class, the number of customers billed on a monthly basis and the number of customers billed on a bi-monthly basis and the number of customers billed on any other applicable frequency.

c) If not, please provide, by rate class, the revenue associated with customers broken out for each billing frequency.

**RESPONSE:**

a) No. PowerStream bills its Residential customers on a bi-monthly basis and the rest of the customers on a monthly basis.

b) Please see table below for total customer numbers billed on a monthly vs. bi-monthly basis.

| Customers | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|
| Customers billed bi-monthly | 327,907 | 333,673 | 339,480 | 345,362 | 351,406 |
| Customers billed monthly | 40,757 | 41,317 | 41,892 | 42,484 | 43,102 |
| **Total Customers** | **368,663** | **374,990** | **381,372** | **387,845** | **394,508** |

c) Please see table below for revenue associated with customers broken out for each billing frequency:

| Revenue | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|
| Customers billed bi-monthly | $ 103,692,721 | $ 114,090,187 | $ 120,370,009 | $ 126,541,479 | $ 132,133,185 |
| Customers billed monthly | $ 87,754,456 | $ 95,913,608 | $ 100,317,080 | $ 104,705,105 | $ 108,735,415 |
| **Total Revenue** | **$ 191,447,177** | **$ 210,003,796** | **$ 220,687,089** | **$ 231,246,584** | **$ 240,868,600** |

**G-Energy Probe-17**

**REF: Ex. G, Tab 3**

In the February 5, 2015 Notice of Proposal for Proposed Amendments to the Distribution System Code, the Board has indicated that distributors must move to monthly billing for all non-seasonal residential and GS<50 customers by January 1, 2017.

a) Are any costs or benefits built into the application to reflect his change?

b) Please provide the estimated costs and benefits of moving to monthly billing beginning in 2017.

c) What is the estimated change in the working capital needed to move these customers to monthly billing?

**RESPONSE:**

a) No.

b) Estimated costs are as follows:

- One-time system related cost: approximately $3M for system development, interface, configuration changes, testing, bill design, etc.

- Incremental on-going OM&A cost: on average about $4.2M annually beginning in 2017 to cover such costs as labour, postage, paper envelops and bills, printing, banking fees, 3rd party collection activities, etc.

Estimated benefits would include 1) an annual reduction on bad debt expense estimated at approximately $358k on average; and 2) an opportunity for customers to budget better with the monthly billing.

c) Please see response to G-CCC.49.

**G-Energy Probe-18**

**REF: Ex. G, Tab 3**

For each electricity distributor in Ontario that has filed a Custom IR filing, please indicate:

i) whether a lead/lag study was as filed as part of the application;

ii) and if so, what the WCA percentage was.

**RESPONSE:**

i. The following LDCs have filed Custom IR Applications: Horizon Utilities, Hydro One Distribution, and Toronto Hydro. All of the above filed a Lead/Lag Study as part of the application.

ii. The WCA percentage filed as per Lead/Lag Study and Board-Approved, if applicable, is summarized in Table G-EP-18-1 below.

**Table G-EP-18-1: WCA % Summary Table**

| LDC | WCA % as per Lead/Lag Study | WCA % Board-Approved |
|---|---|---|
| Horizon Utilites | **12.70%** | **12.00%** |
| Hydro One | **7.47%** | **7.40%** |
| Toronto Hydro | **7.99%** | **N/A** |

**G-Energy Probe-19**

**REF: Ex. G, Tab 4 & G-4-1**

Please provide a live Excel version of G-4-1 that includes all the formulae used in the calculation of the total cost of power.

**RESPONSE:**

Please refer to G-Energy Probe-19 Appendix A for Cost of Power calculation.

**G-Energy Probe-20**

**REF: Ex. G, Tab 4**

a) PowerStream proposes to update the cost of power forecast for the commodity and global adjustment rates for RPP and non-RPP customers to reflect the most current parameters in the RPP Price Reports for 2016. Does PowerStream also propose to update the IESO related charges and/or Hydro One related charges based on the most current information available at the same time as the update of the commodity and global adjustment rates? If not, why not?

b) For 2017 through 2020, please confirm that PowerStream is not proposing to update the load forecast or the split between RPP and non-RPP volumes based on the most recent information available.

**RESPONSE:**

a) Yes. PowerStream is proposing to update the IESO related charges and/or Hydro One related charges based on the most current information available at the same time as the update of the commodity and global adjustment rates.

b) Confirmed. PowerStream is not proposing to update the load forecast or the split between RPP and non-RPP volumes based on the most recent information available.

**G-SEC-15**

**REF: Ex. G-2**

Does PowerStream have a longer term capital plan than what was included in its Distribution System Plan, either as a separate document or part of another document? If so, please provide a copy.

**RESPONSE:**

Please see latest version of PowerStream's Corporate 10 Year Plan attached as G-SEC-15 Appendix A.

**G-SEC-16**

**REF: Ex. G-2-5.2.3, p.4-5**

With respect to the Work Order Closing Variance Metric:

a. What level of variance requires management approval? i.e. the “prescribed limits”?

b. It would appear from Figure 2 that in 2014 only 42% of work orders were completed within the variance (not requiring management approval). Please explain the reasons for this low number and any corrective actions that PowerStream is undertaking.

c. For 2014, please provide for all work orders that are part of Figure 2, the total actual dollars spent and the total approved budgeted amounts.

d. Please provide similar information as set out in Figure 2, for 2012 and 2013.

e. Please provide similar information as requested in part (c) for 2012 and 2013.

**RESPONSE:**

a) The level of variance that would require management approval is as follows:

- for Projects with Gross Actual Totals of $100k or more, variances of +/-10%, or more, require management approval;
- for Projects with Gross Actual Totals of $25k-$100k, variances of +/-15% or more, require management approval; and
- for Projects with Gross Actual Totals of less than $25k, variances of +/-25% or more, require management approval.

b) As shown in Figure 2, the 42% represents 235 out of 553 work orders reviewed in 2014 that did not require management approval. Analysis of the causes for the 58% of work orders that did require management approval shows that the largest cause was labour-related, primarily less labour required than originally estimated. PowerStream is using findings from the Work Order Review and Closing Variance Metric to improve processes, and is investigating changes to improve work order estimating.

c) For 2014, for all work orders that are part of Figure 2, the total actual dollars spent and the total approved budgeted amounts are shown in the table below:

| | 2014 | 2014 |
|---|---|---|
| **Category and # of Work Orders** | **Sum of WO Gross Budget $** | **Sum of WO Actual $** |
| **Capital (167)** | $ 32,765,315 | $ 28,262,639 |
| **ICI (58)** | $ 2,124,799 | $ 2,438,106 |
| **Subdivision (32)** | $ 7,210,501 | $ 6,293,873 |
| **Non-Paper Trail (61)** | $ 9,810,060 | $ 10,262,967 |
| **Total (318)** | **$ 51,910,676** | **$ 47,257,586** |

d) The Table as set out in Evidence Figure 2 for Year 2013 is shown below. The Work Order Review and Closing Process, in its current form, did not exist in 2012.

| Work Order Review | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | 2013 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **# of Reviews Issued Requiring Management Approval** | | | | | | | | | | | | | |
| Capital | - | 12 | - | 10 | - | 8 | 8 | 4 | - | - | 15 | 11 | 68 |
| ICI | - | - | - | 3 | - | 7 | 4 | 2 | - | - | 1 | 13 | 30 |
| Subdivision | 1 | - | - | 3 | - | 5 | 4 | 2 | - | - | - | 9 | 24 |
| Non Paper Trail | - | - | - | - | - | - | - | - | - | - | - | - | 0 |
| **TOTAL** | 1 | 12 | 0 | 16 | 0 | 20 | 16 | 8 | 0 | 0 | 16 | 33 | 122 |
| **# of Reviews Not Requiring Management Approval** | | | | | | | | | | | | | |
| Capital | - | 9 | 3 | - | 1 | - | - | 1 | - | - | 15 | - | 29 |
| ICI | - | - | - | - | 2 | 3 | 6 | 1 | - | - | 5 | - | 17 |
| Subdivision | - | 2 | 1 | - | - | 1 | - | 2 | - | - | - | - | 6 |
| Non Paper Trail | - | - | - | - | - | - | - | - | - | - | - | - | 0 |
| **TOTAL** | 0 | 11 | 4 | 0 | 3 | 4 | 6 | 4 | 0 | 0 | 20 | 0 | 52 |
| **Percent of Work Orders Completed Within Variance (Not Requiring Management Approval)** | | | | | | | | | | | | | |
| % | 0 | 48 | 100 | 0 | 100 | 17 | 27 | 33 | N/A | N/A | 56 | 0 | 30 |

e) For 2013, for all work orders that are part of table above, the total actual dollars spent and the total approved budgeted amounts are shown in the table below. The Work Order Review and Closing Process, in its current form, did not exist in 2012.

| Category and # of Work Orders | 2013<br>Sum of WO Gross Budget $ | 2013<br>Sum of WO Actual $ |
|---|---|---|
| **Capital (68)** | $ 7,116,319 | $ 6,355,446 |
| **ICI (30)** | $ 942,576 | $ 916,823 |
| **Subdivision (24)** | $ 7,069,032 | $ 5,576,371 |
| **Non-Paper Trail (0)** | N/A | N/A |
| **Total (122)** | **$ 15,127,927** | **$ 12,848,640** |

**G-SEC-17**

**REF: Ex. G-2-5.2.3, p.6**

Please provide relevant examples of the implementation of the “Journey to Excellence”.

**RESPONSE:**

As noted in the Consolidated Distribution System Plan, Section 5.2.3, page 6 of 19, one of the six driving forces behind the journey is customer experience. Examples that support the Journey to Excellence with respect to customers include PowerStream’s implementation of its customer experience plan, customer satisfaction surveys, and the DS Plan public engagement included in the DS Plan.

**G-SEC-18**

**REF: Ex. G-2-5.2.3, p.6**

Please provide a copy of the Customer Experience Plan.

**RESPONSE:**

Please see G-SEC-18 Appendix A for Customer Experience Plan

**G-SEC-19**

**REF: Ex. G-2-5.2.3, p.10-11**

With respect to the 2013 Ice Storm, please provide copies of the referenced:

a. Internal report

b. System Hardening report.

**RESPONSE:**

These reports are attached as G-SEC-19 Appendix A (internal report) and G-SEC-19 Appendix B (System Hardening report).

**G-SEC-20**

**REF: Ex. G-2-5.2.3, p.14-16**

With respect to reliability metrics:

a. Please provide in tabular form Figures 3, 4 and 5.

b. Please provide in tabular form Figures 6, 7 and 8.

c. Please provide a forecast for SAIDI, SAIFI and CAIDI for 2016-2020.

**RESPONSE:**

a)

| | PowerStream - All Events | | | PowerStream Total Excluding LOS | | |
|---|---|---|---|---|---|---|
| | **CAIDI** | **SAIFI** | **SAIDI** | **CAIDI** | **SAIFI** | **SAIDI** |
| **2007** | 1.152 | 1.923 | 2.216 | 1.168 | 1.801 | 2.105 |
| **2008** | 0.964 | 1.463 | 1.409 | 0.968 | 1.148 | 1.112 |
| **2009** | 1.603 | 1.232 | 1.975 | 1.484 | 1.068 | 1.585 |
| **2010** | 0.881 | 0.923 | 0.813 | 0.67 | 0.801 | 0.537 |
| **2011** | 09.76 | 1.231 | 1.201 | 1.043 | 1.003 | 1.046 |
| **2012** | 0.679 | 1.703 | 1.156 | 0.681 | 1.529 | 1.041 |
| **2013** | 4.202 | 2.542 | 10.679 | 4.368 | 2.237 | 9.771 |
| **2014** | 0.85 | 1.708 | 1.452 | 0.848 | 1.642 | 1.393 |

b)

| | CEA (Urban Utilities) | | | PowerStream | | |
|---|---|---|---|---|---|---|
| Year | **SAIFI** | **SAIDI** | **CAIDI** | **SAIFI** | **SAIDI** | **CAIDI** |
| **2008** | 1.44 | 1.73 | 1.20 | 1.46 | 1.41 | 0.96 |
| **2009** | 1.33 | 1.80 | 1.35 | 1.23 | 1.98 | 1.60 |
| **2010** | 1.42 | 1.87 | 1.32 | 0.92 | 0.81 | 0.88 |
| **2011** | 1.36 | 1.63 | 1.20 | 1.23 | 1.20 | 0.98 |
| **2012** | 1.82 | 1.93 | 1.06 | 1.70 | 1.16 | 0.68 |
| **2013** | 1.74 | 6.52 | 3.75 | 2.54 | 10.68 | 4.20 |

c) Powerstream's reliability model has only been created to forecast future SAIDI figures. For the years 2016-2020, the Predicted SAIDI Reliability figures, as seen in Section 5.3.3, page 37 of 38, Figure 8, are tabulated below.

| **Year** | **2016** | **2017** | **2018** | **2019** | **2020** |
|---|---|---|---|---|---|
| SAIDI Upper Limit (Minutes) | 82.87 | 82.67 | 82.64 | 81.07 | 81.07 |
| SAIDI target (Minutes) | 68.02 | 64.69 | 61.54 | 59.97 | 59.97 |
| SAIDI Lower Limit (Minutes) | 53.46 | 50.13 | 46.98 | 45.41 | 45.41 |

**G-SEC-21**

**REF: Ex. G-2-5.2.3**

Please explain how PowerStream is planning to be more efficient in executing its capital program in each of the plans. Please explain how that has been built into the plan budget.

**RESPONSE:**

PowerStream is not clear what is being asked by “in each of the plans”. To be of assistance PowerStream responds as below.

Section 5.2.3 is about Performance Measurement for Continuous Improvement. The Board’s understandings and expectations are set out at the beginning of section 5.2.3 and PowerStream has provided detailed evidence in that section. As noted in the section, PowerStream will be using performance metrics 5 and 6 to monitor its execution of its plans. These metrics will assist PowerStream in driving to excellence in project execution to meet project scope, budget and timelines.

Moreover, the capital investments and spending levels detailed in Exhibit G, Tab 2, Section 5.4.5 Justifying Capital Expenditures, represents the optimized minimum expenditures required to maintain the PowerStream distribution system in a reliable, and economical, state of repair for the present and the long term. The proposed capital expenditures documented in the Distribution System Plan are the result of a well-defined Asset Management Process as described in Section 5.4.1 of Exhibit G, Tab 2. As noted on page 3 of 28 PowerStream’s asset management planning process, PowerStream uses corporate objectives (Foundations, Processes, Customers, Financial) as guiding principles in the decision making process to ensure that effective short and long term investment decisions are made to maximize the value of the assets to the company and provide optimal value to customers.

While this is the first DSP Plan, and as such demonstration of continuous productivity improvements is a going forward proposition, PowerStream has provided throughout the DSP Plan and in its Rate Proposal how continuous improvements have been incorporated into its capital plan. With respect to the latter, please see Exhibit F, Tab 1 for several examples of initiatives and the efficiencies as a result of these initiatives.

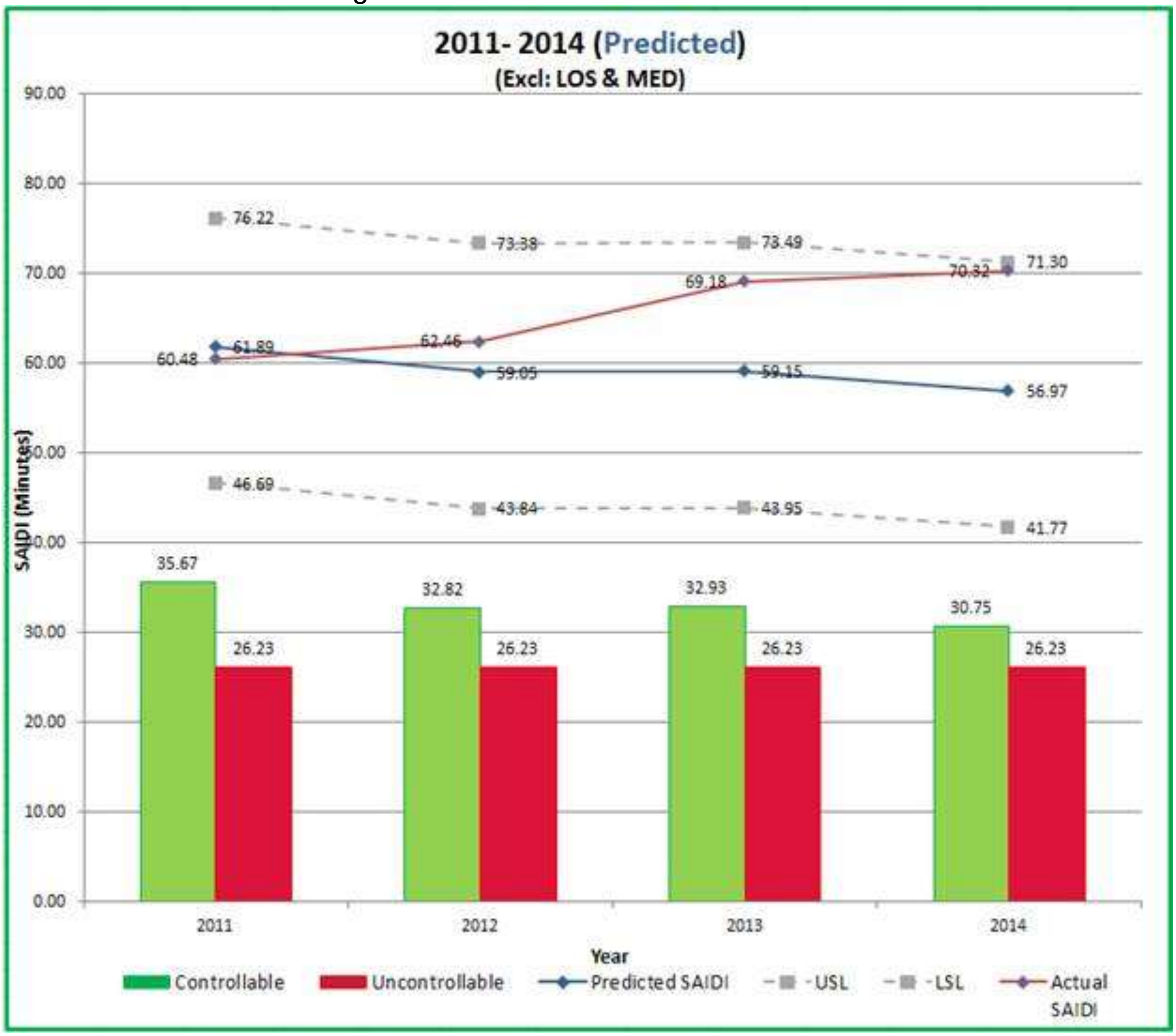
**G-SEC-22**

**REF: Ex. G-2-5.3.3, p.38**

Using the same methodology as proposed but using old data, please provide what would have been the predicted SAIDI measures for 2011-2014.

**RESPONSE:**

The model has been modified to provide the predicted SAIDI for 2011- 2014. The results are shown in the Figure below.




## G-SEC-23

**REF: Ex. G-2-5.4.1, p.6-9**

Please expand table 2-5 to include 2011-2014 expenditures.

**RESPONSE:**

Tables 2-5 have been expanded to include 2011-2014 expenditures where the 2015-2020 Material Investments had expenditures in 2011-2014.

## Table 2: Material Investments - System Access

| | Historical | | | | | Proposed | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Material Investments** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
| **System Access** | **Actual** | **Actual** | **Actual** | **Actual** | **Plan** | **Plan** | **Plan** | **Plan** | **Plan** | **Plan** |
| **New Connections and Subdivisions** | **($)** | **($)** | **($)** | **($)** | ($) | ($) | ($) | ($) | ($) | ($) |
| New Commercial Subdivision Development | - 6,859 | 316,257 | 1,365,649 | 1,249,667 | 1,600,010 | 1,601,908 | 1,603,808 | 1,605,707 | 1,607,607 | 1,609,506 |
| New Residential Subdivision Development | 473,519 | 10,593,928 | 3,799,355 | 3,956,902 | 7,895,964 | 8,633,109 | 9,392,346 | 9,759,944 | 10,135,066 | 10,517,394 |
| New Subdivision Development - Secondary Service Lateral | 1,383,741 | 1,716,273 | 2,428,920 | 2,348,217 | 1,989,034 | 2,173,796 | 2,364,815 | 2,458,773 | 2,554,113 | 2,650,954 |
| O/H and U/G Residential Service Upgrades | 900,744 | 730,652 | 762,179 | 925,892 | 928,921 | 984,657 | 1,043,737 | 1,106,360 | 1,172,741 | 1,243,109 |
| **Road Authority** | | | | | | | | | | |
| Road Authority Expenditures | 7,536,780 | 2,812,835 | 2,513,594 | 13,896,134 | 6,258,891 | 9,701,973 | 8,678,858 | 8,356,668 | 5,718,617 | 6,221,949 |
| **Metering** | | | | | | | | | | |
| GS>50 MIST Meter Program Implementation | - | - | - | - | 1,592,952 | 1,196,859 | 1,303,795 | 1,308,610 | 1,195,725 | 574,761 |
| Residential Meter "ICON F" Meter Replacement Program | - | - | - | - | 411,051 | 494,361 | 494,746 | 872,435 | 2,280,384 | 4,517,454 |
| **Other Customer Initiated Work** | | | | | | | | | | |
| Unforeseen Projects Initiated by the Customer | 1,990,470 | - 845,891 | 273,294 | 1,075,163 | 329,005 | 786,802 | 929,401 | 1,080,390 | 1,255,781 | 1,414,541 |
| **Total Material Investments System Access** | **12,278,396** | **15,324,054** | **11,142,991** | **23,451,976** | **21,005,828** | **25,573,466** | **25,811,508** | **26,548,888** | **25,920,034** | **28,749,669** |

## Table 3: Material Investments - System Renewal

| | Historical | | | | | Proposed | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Material Investments** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
| **System Renewal** | **Actual** | **Actual** | **Actual** | **Actual** | **Plan** | **Plan** | **Plan** | **Plan** | **Plan** | **Plan** |
| **UG Lines - Planned Asset Replacement** | **($)** | **($)** | **($)** | **($)** | ($) | ($) | ($) | ($) | ($) | ($) |
| Cable Injection Program | 349,694 | 771,664 | 4,141,808 | 5,913,763 | 4,024,219 | 4,138,312 | 4,255,465 | 4,375,771 | 4,499,323 | 4,626,219 |
| Cable Replacement Program | 3,917,735 | 2,219,486 | 15,417,075 | 15,036,321 | 11,718,862 | 12,538,684 | 13,607,273 | 14,288,297 | 15,085,861 | 15,340,181 |
| Emerging Cable Replacement Projects | 119,989 | 1,968,435 | 1,463,874 | 1,070,775 | 491,687 | 520,801 | 1,050,756 | 1,081,576 | 1,113,287 | 1,145,915 |
| Submersible Transformer Replacement - North | 6,451 | 508,952 | 1,168,202 | 856,776 | 1,040,300 | 620,000 | - | - | - | - |
| Switchgear Replacement Program | 566,295 | 662,337 | 990,400 | 2,138,988 | 2,003,445 | 2,327,404 | 2,462,129 | 2,533,373 | 2,606,624 | 2,681,945 |
| **Distribution Lines - Emergency/Reactive Replace** | | | | | | | | | | |
| Storm damage - Replacement of Distribution Equip due to Storms | 428,418 | 482,911 | 767,149 | 1,160,050 | 999,785 | 1,000,232 | 1,005,603 | 1,005,624 | 1,010,352 | 1,010,159 |
| Switchgears - Unscheduled Replacement of Failed Switchgear | - | 1,381,861 | 1,663,004 | 1,495,974 | 1,420,148 | 1,431,384 | 1,420,148 | 1,421,218 | 1,400,444 | 1,140,858 |
| Unscheduled Replacement of Other Failed Distribution Equip | 6,525,087 | 4,878,957 | 4,791,473 | 4,890,357 | 4,904,357 | 5,107,035 | 5,206,156 | 5,358,281 | 5,455,354 | 5,305,986 |
| **Overhead Lines - Planned Asset Replacement** | | | | | | | | | | |
| Pole Replacement Program | 1,638,822 | 4,111,507 | 5,045,992 | 4,872,277 | 4,645,383 | 4,933,143 | 5,570,700 | 5,870,246 | 6,241,483 | 6,244,377 |
| Unforeseen Projects Initiated by PowerStream | 1,076,240 | 1,499,516 | 4,232,576 | 2,429,637 | 1,046,472 | 1,070,527 | 1,093,812 | 1,117,360 | 1,141,172 | 1,165,266 |
| **Storm Hardening** | | | | | | | | | | |
| Storm Hardening & Rear Lot Supply | - | - | - | - | 3,499,998 | 7,900,017 | 7,999,752 | 7,499,834 | 6,900,540 | 7,200,072 |
| **Stations/P&C - Planned & Emergency** | | | | | | | | | | |
| Planned Circuit Breaker Replacement Markham TS1&2, Lazenby | - | - | - | - | 747,766 | - | - | 1,087,788 | 1,119,281 | - |
| Station Switchgear Replacement (ACA) 8th Line MS323 | - | - | - | - | - | - | 412,339 | 1,106,666 | - | - |
| Station Switchgear Replacement (ACA) Patterson MS336 | - | - | - | - | - | - | - | 421,896 | 895,805 | - |
| **Total Material Investments System Renewal** | **14,628,731** | **18,485,627** | **39,681,553** | **39,864,918** | **36,542,420** | **41,587,538** | **44,084,133** | **47,167,931** | **47,469,526** | **45,860,979** |

## G-SEC-24

## REF: Ex. G-2, 5.4.1

Please complete the table included in the attached SEC_PowerStream_Form.xls.

## RESPONSE:

Completed. See Table SEC_PowerStream_Form below:

| | Actual | | | | Forecast | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
| **Underground Lines - Planned Asset Replacement** | | | | | | | | | | |
| Cable Injection Program Cost | $349,694 | $771,664 | $4,141,808 | $5,913,763 | $4,024,219 | $4,138,312 | $4,255,465 | $4,375,771 | $4,499,323 | $4,626,219 |
| Kilometers of Cable Injection Completed | 9.57 | 25.1 | 85.363 | 106.976 | 105 - 115 | 105 - 115 | 105 - 115 | 105 - 115 | 105 - 115 | 105 - 115 |
| Cable Replacement Program Cost | $3,917,735 | $2,219,486 | $15,417,075 | $15,036,321 | $11,718,862 | $12,538,684 | $13,607,273 | $14,288,297 | $15,085,861 | $15,340,181 |
| Kilometers of Cable Replacement Completed | 10.33 | 9.06 | 49.539 | 54.499 | 25 - 30 | 25 - 30 | 25 - 30 | 25 - 30 | 25 - 30 | 25 - 30 |
| Emerging Cable Replacement Program Cost | $119,989 | $1,968,435 | $1,463,874 | $1,070,775 | $491,687 | $520,801 | $1,050,756 | $1,081,576 | $1,113,287 | $1,145,915 |
| Kilometers of Emerging Cable Replacement Completed | 2011-2014 quantities are included in above totals | | | | 1-2 | 1-2 | 2-4 | 2-4 | 2-4 | 2-4 |
| Submersible Transformer Replacement Program Cost | 6,451 | 772,357 | 1,294,952 | 857,249 | 1,040,300 | 620,000 | | | | |
| # of Submersible Transformer Replaced | 20 | 32 | 24 | 10 | 8 | 4 | | | | |
| Switchgear Replacement Program Cost | $566,295 | $662,337 | $990,400 | $2,138,988 | $2,003,445 | $2,327,404 | $2,462,129 | $2,533,373 | $2,606,624 | $2,681,945 |
| # of Switchgears Replaced | 12 | 7 | 20 | 50 | 31 | 36 | 36 | 36 | 36 | 36 |
| **Distribution Lines - Emergency/Reactive Replace** | | | | | | | | | | |
| Unscheduled Replacement of Failed Switchgear Program Cost | $0 | $1,381,861 | $1,663,004 | $1,495,973 | $1,420,148 | $1,431,384 | $1,420,148 | $1,421,218 | $1,400,444 | $1,140,858 |
| # of Switchgears Replaced | 0 | 36 | 42 | 34 | | | | | | |
| **Overhead Lines - Planned Asset Replacement** | | | | | | | | | | |
| Pole Replacement Program Cost | $1,638,822 | $4,111,507 | $5,045,992 | $4,872,277 | $4,645,383 | $4,933,143 | $5,570,700 | $5,870,246 | $6,241,483 | $6,244,377 |
| # of Poles Remediated | 117 | 315 | 368 | 453 | 400 | 400 | 400 | 400 | 400 | 400 |

**G-SEC-25**

**REF: Ex. G-2, Appendix A**

Please provide a table showing the capital cost for each material capital investment per year, and the OM&A savings related to that investment per year.

**RESPONSE:**

For the capital costs of each material capital investment, please refer to Tables 2-5 in Exhibit G Tab 2 Section 5.4.1 Pages 6-8 of 11 of the Consolidated Distribution System Plan.

O&M savings, related to each capital investment per year, are described in Exhibit G, Tab 2, Section 5.3.3 Page 30 of 38 of the Consolidated Distribution System Plan.

**G-SEC-26**

**REF: Ex. G-2, Appendix A**

Please explain how PowerStream determined the budget for its storm damage or unscheduled replacement programs.

**RESPONSE:**

In general, for reactive programs such as Storm Damage or Unscheduled Replacement, the budget was based on historical averages and trends from 2011 – 2014.

Specifically, as stated in the Distribution System Plan, Appendix A, page 311 of 730, Project Summary Report, Storm Damage, Project 101800, Section 4: "The budget for this category is based primarily on historical trends over the past few years."

Specifically, as stated in the Distribution System Plan Project, Appendix A, page 319 of 730, Project Summary Report, Unscheduled Replacement of Failed Equipment – Poles, etc, Project 101824, Section 3. (Comparative Information on Equivalent Historical Projects), "Historical number of events and associated costs are the basis for estimating future planned expenditures."

**G-SEC-27**

**REF: Ex. G-2**

With respect to contractor labour:

a. Please explain how PowerStream utilizes contractor and/or external services for its capital and OM&A programs.

b. For the period 2012-2020, please provide the annual OM&A expenditures for all external contract services, Also provide the percentage this represents of total annual OM&A expenditures.

c. For the period 2012-2022, please provide the annual capital expenditures for all external contract services. Also provide the percentage this represents of total annual capital expenditures.

**RESPONSE:**

a) PowerStream utilizes contractors for both capital and O&M work.

For capital work on the distribution system, PowerStream uses an “in-house” contractor (a contractor that bids for routine and repetitive annual construction work) for new connections, upgrades, civil construction and subdivision Option “A” construction. A different “in-house” contractor is also used for pole line construction projects. Contractors are also deployed within metering and information services. Contractors are selected based on resourcing requirements, specialized expertise or specialized equipment and services. These contracts are awarded through a competitive bidding process.

For capital work on municipal stations and transformer stations, PowerStream uses approved contractors which have been awarded the work through a competitive bidding process.

For O&M work, as noted in the Consolidated Distribution System Plan, Section 5.3.3, page 26 of 38, PowerStream uses approved contractors which have been awarded the work through a competitive bidding process.

There are also contractors for work such as crane operators and vacuum excavation trucks that may be either capital or O&M.

All contracts, in addition to those noted above, are awarded in compliance with PowerStream's Procurement Policy.

b) For the period 2012 to 2020 the annual OM&A expenditures for Program and Maintenance related OM&A external contract services is detailed in the table below. Also included is the percentage that represents OM&A contract consulting as a percentage of total OM&A.

| $(000) | Actual | | | Budget | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Year | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
| OM&A Program & Maintenance Related contract/consulting | $8,354 | $8,812 | $9,029 | $10,179 | $10,834 | $11,508 | $12,184 | $12,869 | $13,563 |
| Total OM&A | $82,792 | $80,849 | $85,454 | $92,558 | $96,216 | $98,112 | $99,920 | $102,195 | $104,193 |
| Percent of annual OM&A Expenditures | 10% | 11% | 11% | 11% | 11% | 12% | 12% | 13% | 13% |

c) See Table below for the period 2012-2020. Figures for external contract services are not available for 2021-2022.

| | Actual 2012 | Actual 2013 | Actual 2014 | Budget 2015 | Budget 2016 | Budget 2017 | Budget 2018 | Budget 2019 | Budget 2020 |
|---|---|---|---|---|---|---|---|---|---|
| Contract / Consulting / Prof Serv | 46,409,337 | 56,519,306 | 70,507,262 | 57,216,885 | 60,709,568 | 65,721,892 | 64,740,797 | 70,610,138 | 69,022,129 |
| Total Capital Spend - Rate Based | 74,915,000 | 93,500,000 | 109,488,127 | 118,399,999 | 132,800,017 | 131,499,752 | 125,399,834 | 125,400,540 | 125,400,071 |
| | | | | | | | | | |
| % of Total | 62% | 60% | 64% | 48% | 46% | 50% | 52% | 56% | 55% |
| | | | | | | | | | |

**G-SEC-28**

**REF: Ex. G-2, Appendix F**

Please explain how PowerStream modified, if at all, its proposed plan after reviewing the Customer Consultation Report.

**RESPONSE:**

As noted in the DS Plan, Section 5.4.2, PowerStream derived significant benefits from the enhanced level of customer engagement conducted during the preparation of the DS Plan. PowerStream valued the input received from customers and the responses as it confirmed the level of general support customers have for PowerStream's plans and approach to investment.

The plan was not modified after reviewing the Customer Consultation Report. Additional information was requested about the CIS project and this information was included accordingly. The consultation process reconfirmed that PowerStream's plans are aligned with customer preferences in a number of areas including system reliability, weather hardening and asset remediation. Customers endorsed a balanced approach between risk and cost. This is reflected in the DS Plan.

**G-SEC-29**

**REF: Ex. G-2, Appendix F, p.74**

With respect to the Mid-Market General Service Workshop:

a. Please provide a copy of all material provided or used (i.e. scripts, presentations).

b. Did the customers that were randomly selected include all GS>50 customers or a subset of them? If it was a subset, please provide details.

**RESPONSE:**

a) Please see appendices G-SEC-29 A and B for copies of all materials used in the Mid-Market General Service Workshop

b) All of PowerStream's GS>50 customers were included the list of customers that was used to randomly recruit except for Key Account customers, who were included in a separate session.

**G-SEC-30**

**REF: Ex. G-2, Appendix F, p.91**

With respect to the Key Accounts consultation:

a. Please provide a copy of all material provided or used (i.e. scripts, presentations).

b. How many key accounts does PowerStream have?

**RESPONSE:**

a) Please see appendices G-SEC-30 A and B for copies of all materials used in the Key Accounts consultation

b) PowerStream currently has 132 accounts within the Key Accounts program.

**G-VECC-12**

**REF: Ex. G/T-4/pg. 3-5**

a) With respect to page 3 (lines 23) to page 4 (line 17), please provide schedules that set out the 2011-2013 values used to calculate each of the historic three-year averages described.

**RESPONSE:**

a) Please refer to Table 1-3 below for 2011-2013 values used to calculate each of the historic three-year averages:

### Table 1: IESO Billing Determinants

| Component | Description | 2011 | 2012 | 2013 |
|---|---|---|---|---|
| Energy | Energy Purchased (kWh) | 8,679,606,854 | 8,751,038,327 | 8,694,266,825 |

### Table 2: HydroOne Billing Determinants

| Component | Description | 2011 | 2012 | 2013 |
|---|---|---|---|---|
| Low Voltage | Low Voltage kW | 3,509,649 | 3,597,316 | 3,299,105 |
| Transmission Network | System kW | 2,482,752 | 2,568,626 | 2,530,648 |
| Transmission Connection | System Line Connection kW | 2,493,220 | 2,570,396 | 2,539,712 |

### Table 3: Average Ratios

| | 2011 | 2012 | 2013 | 3-year Averages |
|---|---|---|---|---|
| Transmission Network/Energy Purchased | 0.029% | 0.029% | 0.029% | **0.03%** |
| Transmission Connection/Transmission Network | 100.422% | 100.069% | 100.358% | **100.28%** |
| Low Voltage/Transmission Network | 141.361% | 140.048% | 130.366% | **137.26%** |

**G-VECC-13**

**REF: Ex. F/T-1/pg. 9 & J/T-3/pg.2**

Pre-amble: PowerStream discusses in different places its cable injection program noting that it is at the forefront of this technology and that it will create a new asset class to record rehabilitated cables. However, there is no discussion of the risk with respect to this technology. The same can be said about the pole reinforcement technology.

a) What studies has the Utility undertaken to understand these risks?
b) How did PowerStream determine a 20 year life for the rehabilitated cable assets?
c) Why has the Utility created a new asset class for rehabilitated cable assets, but not for poles rehabilitated with the pole reinforcement technology?
d) Please provide any precedent for creating a new class for an asset which is being refurbished.

**RESPONSE:**

a) PowerStream completed a technical assessment of cable injection in 2009 and the first pilot project was also completed in 2009. In addition, each year PowerStream analyses the success of the cable injection program and industry developments that have occurred that year.

Dow Corning invented CableCure Restoration Technology in the late 1980s. Cable injection was first used by UtilX in 1989. Approximately 39 million meters of cable has been injected since 1989 by over 500 utilities and industrial customers worldwide. There have been numerous studies and papers published establishing cable injection as viable method of extending the life of the cable.

One such report describes research sponsored by EPRI and the U.S. Department of Energy under the Nuclear Energy Plant Optimization (NEPO) Program, Task FYOl-3-8.11, Medium-Voltage Cables in Nuclear Plant Applications - State of Industry and Condition Monitoring, EPRI, Palo Alto, CA, and the U.S. Department of Energy, Washington, D.C.: 2003.1003664.

The report concludes that “Rejuvenation of cables by injection of impregnants has proven to be a reliable technology”.

PowerStream has assessed the success of the cable injection since 2009 and the results have been very favourable.

The performance of the injected cables at PowerStream is described below.

- Segments injected: 2,515 segments
- Meters injected: 220,177 m
- Pre-injection failures (last 3 years): 86
- Post-injection failures: 2 (total length: 252 m + 95 m = 347 m)
- Percentage of failure based on segments:
  2 / 2515 x 100 = 0.08%
- Percentage of failure based on meters:
  347 / 220177 x 100 = 0.16%

Based on experience from cable injection companies, the failure rate of injected cable in North America is approx. 1% (i.e. 1% of the total cables failed after being injected). The failure rate to date at PowerStream is very low (less than 0.2%).

PowerStream reinforces only the poles that are degraded at the ground line and can be restored by reinforcement. The pole reinforcement candidates are determined by testing and visual inspection. The manufacturer warrants that the patented design and superior strength of the steel allows for poles to be restored which have ground line shell thickness from as little as one inch to zero. In other words, if the pole has no remaining strength at the ground line while the top is in good condition the reinforced pole can be considered to be restored back to the original pole strength.

While pole reinforcement is new to Ontario, this technology has been adopted in Western Canada and numerous utilities in the U.S.A. PowerStream to date has only reinforced a small number of poles within the pilot project in 2014. The results are promising, and as such PowerStream has included the continuation of the pole reinforcement program at a modest 30 poles per year.

b) The 20 year life for the rehabilitated cables is based on the warranty provided by the cable injection vendor for the failure of the cable or splice after it has been injected.

c) PowerStream’s cable injection program is well established having started in 2009 whereas the pole reinforcement pilot project was initiated in 2014. Additional information and assessment is required prior to the creation of a new asset class for poles that have been reinforced.

d) When remediation has extended the life of an asset, IFRS states that significant parts of an asset should be depreciated separately. In order to depreciate it separately, a new asset class is required.

**G-VECC-14**

**REF: Ex. G-2-1 DSP Appendix//pg.37**

a) Please explain how the potential emerging reliability SAIDI figures were derived.

**RESPONSE:**

a) The new emerging reliability figures were included to account for issues that periodically arise that we cannot foresee (an example of this are the recent pole fires that occurred in March of 2015).

Standard Deviation of controllable SAIDI performance between the years 2008-2014 was used to generate the potential emerging value.

**G-VECC-15**

**REF: Ex. G/T-2/pg. 17 Appendix G-2-1 Consolidated DSP**

a) Please provide the SAIFI and SAIDI figures for each of 2009 through 20120 (forecast) for outages separately by cause codes:
   - (5) Defective Equipment
   - Schedule Outage
   - Tree Contact

b) Please explain if PowerStream intends to develop/use any metrics with respect to measuring the performance of the distribution system plan.

**RESPONSE:**

a) The Reliability Model was developed in 2014, which breaks down reliability contributions for each cause code for 2015-2020. A detailed forecast was not created prior to 2014 therefore the requested forecast for 2009-2012 is not available.

The actual SAIDI/SAIFI figures shown below exclude LOS & MED.

| | 2009 | | 2010 | | 2011 | | 2012 | |
|---|---|---|---|---|---|---|---|---|
| | SAIDI | SAIFI | SAIDI | SAIFI | SAIDI | SAIFI | SAIDI | SAIFI |
| Defective Equipment | 26.45 | 0.39 | 14.28 | 0.32 | 30.63 | 0.47 | 30.48 | 0.51 |
| Scheduled Outage | 6.47 | 0.03 | 3.26 | 0.03 | 4.07 | 0.04 | 4.32 | 0.04 |
| Tree Contact | 3.37 | 0.05 | 2.64 | 0.03 | 1.82 | 0.03 | 3.05 | 0.05 |

b) As noted in the Consolidated Distribution System Plan, Section 5.2.3, page 2 of 19, PowerStream intends to use several metrics to measure the performance of the distribution system plan.

## G-VECC-16

## REF: Ex. G/T-2/pg.4 & Appendix G-2-1 Consolidated DSP/pg. 52

a) Please provide a table showing each of the five municipal stations anticipated to be built, the forecast spending in each year of the plan and the total forecast cost of each station.
b) Please confirm that these amounts are in the forecast capital budget of the rate proposal.
c) Please provide the start and completion date forecast for each station.

## RESPONSE:

a) The table is shown below.

| Municipal Substation | Spending Forecast | | | | | | | | Total Cost | Start Date | Completion Date |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | | | |
| Dufferin South MS#2 | | | $749,000 | $2,299,074 | $4,899,189 | | | | $7,947,263 | 2016 | 2019 |
| Harvie Rd. MS | | | $749,000 | | | | $1,700,333 | $3,311,820 | $5,761,153 | 2016 | 2022 |
| Little Lake MS#2 | | $1,125,311 | $1,603,656 | $3,095,457 | | | | | $5,824,424 | 2015 | 2018 |
| Melbourne MS#2 | | | $749,000 | $1,651,393 | $3,187,430 | | | | $5,587,823 | 2016 | 2019 |
| Mill Street MS#2 | | | $642,000 | $1,821,953 | $3,529,079 | | | | $5,993,032 | 2016 | 2019 |

b) These amounts are included in the DS Plan.

c) The dates are included in the table above.

**G-VECC-17**

**REF: Ex. G/T-2a/pg. 1**

a) Why are the 2012 and 2013 in-service additions much lower than the 2014 and projected 2015-20 amounts?

b) Are the 2014 in-service figures (total $95.9) actuals or forecast? If the latter, when will the 2014 actual (audited or unaudited) results be known?

**RESPONSE:**

a) There 2014 to 2020 in-service additions are higher than the 2012 and 2013 additions due to:

- Replacement of the thirty year old Customer Information System ("CIS") in-service in 2015 at a cost of $42.7 million;
- New transformer station in Vaughan (TS#4) in–service in 2017 at a cost of $21.9 million; and
- Increased capital spending as detailed in the Distribution System Plan. Much of increased spending is under Sustainment - replacement of aging infrastructure, in particular underground cable and poles.

b) The 2014 in-service additions are actual unaudited amounts.

## G-VECC-18

## REF: Ex. G/T-2/pg.4 & Appendix G-2-1 Consolidated DSP/5.4.1./pg. 8

### Table 5: Material Investments - General Plant

| Material Investments | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|
| **General Plant** | **($ )** | **($ )** | **($ )** | **($ )** | **($ )** | **($)** |
| **Customer Information System (CIS)** | | | | | | |
| CIS Modifications | 1,403,400 | 3,884,100 | 6,708,900 | 2,996,000 | 2,996,000 | 2,996,000 |
| CIS Replacement Project | 10,300,000 | - | - | - | - | - |
| **IT & Info/Communication Systems** | | | | | | |
| JD Edwards Application Upgrade | - | - | - | - | 2,396,800 | - |
| MSBPI | - | 10,000 | 60,000 | 899,999 | 50,000 | 10,000 |
| Phone System enhancement Upgrade | - | - | - | - | 50,500 | 908,999 |
| Storage Expansion (Data) | 321,000 | 300,000 | 300,000 | 300,000 | 1,000,000 | 400,000 |
| Work Force Management / Mobile Dispatch | 1,605,000 | 2,675,000 | 802,500 | 802,500 | 535,000 | 535,000 |
| **Buildings & Emerging Operations** | | | | | | |
| Barrie Building Renovation Project 2015 | 3,149,489 | - | - | - | - | - |
| **Fleet** | | | | | | |
| Replace various Light and Medium Duty Vehicles | - | - | - | - | 829,250 | 888,100 |
| Replace various Single Bucket and Double Bucket Trucks | - | - | - | 2,193,500 | 1,605,000 | 1,391,000 |
| **Interest Capitalization** | | | | | | |
| Interest Capitalization | 1,000,000 | 1,020,000 | 1,040,000 | 1,061,000 | 1,082,000 | 1,104,000 |
| **Total Material Investments General Plan** | **17,778,890** | **7,889,100** | **8,911,400** | **8,252,999** | **10,544,550** | **8,233,100** |

a) Please reconcile the CIS spending shown in the above table (taken from the DSP) with the CIS projected costs of $19.9 million shown at G/T2/pg.6.

b) Please provide the annual maintenance costs and (separately) training costs for the new CIS system for each of 2015 through 2020.

## RESPONSE:

a) The difference between the CIS amounts shown in Table 5, Exhibit G, Tab 2, Section 5.4.1 page 8 of 11, and the CIS projected costs of $19.9M stated in Exhibit G, Tab 2, page 6 of 6 is due to the fact that the $19.9M also includes another smaller CIS project. This smaller CIS project amount is less than the material threshold of $771k, hence not included, and has expenditures in 2016, 2017, and 2020, totaling $321,000.

b) The table below identifies annual maintenance and training cost for the new CIS system. The annual maintenance activity for the new CIS system will be performed by CGI. CGI will provide a fully managed, end to end solution for application management services (AMS) of the CC&B Customer Information System.

**Table G – VECC - 18: CIS Application Managed Services (AMS) and Training costs (000's)**

| Department | Cost Category | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|
| Information Services | AMS | $2,016 | $2,000 | $2,000 | $2,000 | $2,000 | $2,000 |
| Information Services | Oracle CC&B Software Maintenance | $530 | $535 | $540 | $546 | $551 | $557 |
| Information Services | Training | $11 | $15 | - | - | - | - |
| Customer Service | Training | $19 | $30 | $6 | - | - | - |

**G-VECC-19**

**REF: G-2-1 Consolidated DSP (pdf pg. 450-)**

The entire justification for $4.6 million in renovations to the Barrie building appears to be to create corporate uniformity in office space. The building is noted as being 20 years old.

a) How many staff are housed in this building?
b) When was the building last renovated?
c) It is noted that there is potential for leasing extra space in this building. Please explain what amount of space and expected revenue might be expected.

**RESPONSE:**

a) The Barrie building accommodates 107 employees.

b) This is the first renovation for this building since it was built in 1989/1990 excluding minor changes to accommodate business needs.

c) PowerStream will have available 7,000 square feet for potential lease. It is believed that the space may lease for $8.00 - $10.00/sqf.

# EXHIBIT H: DISTRIBUTION REVENUE

**H-Energy Probe-21**

**REF: Ex. H, Tab 1 & Appendix H-1-3**

a) Please provide a live Excel spreadsheet that includes all the data used to estimate the residential, GS < 50, GS > 50, sentinel lighting and street lighting rate class equations in Appendix H-1-3, including all the dependent and independent variables used. Please provide the information used for each rate class on a separate sheet within the live Excel spreadsheet.

b) Please separate out each of the three components in the residential equation used in the Pop*PCI*EI index variable.

c) Please include in the live Excel spreadsheet any independent variables that were included in the various model estimates, but were not included in the final versions of the models.

d) Please include on each sheet within the live Excel spreadsheet, the estimated regression model statistics and the forecasts by month over the 2015 through 2020 period for each of the independent variables and the forecast sales generated by the equation.

**RESPONSE:**

a) Please refer to H-Energy Probe-21 Appendix A for live Excel spreadsheet that includes all the data used to estimate the rate class equations for Residential, GS < 50 kW, GS > 50 kW, Sentinel Lighting and Street Lighting.

b) Please refer to response to H -VECC – 22 c)

c) Please refer to H-Energy Probe-21 Appendix C for live Excel spreadsheet for independent variables that were included in the various model estimates, but were not included in the filed proposed model. The detailed results of the model evaluation are also presented in this Appendix.

d) Please refer to H-Energy Probe-21 Appendix D for live Excel spreadsheet including the estimated regression model statistics, monthly forecasts (2015-2020) and the forecast sales generated by the equation.

**H-Energy Probe-22**

**REF: Ex. H, Tab 1**

a) Please confirm that the sales data used is all based on smart meter data that allows the reporting of actual consumption by rate class by calendar month. If this cannot be confirmed, how has PowerStream adjusted the billing cycle data to reflect changes in unbilled amounts in order to calculate calendar month data?

b) Please provide a live Excel spreadsheet that shows, by month, the values of the

HDD and CDD variables for 2005 through 2014, referenced on page 6 of 7.

**RESPONSE:**

a) The sales data used is not all based on smart meter data. The monthly sales data used in the load forecast model is comprised of billed and unbilled sales.

To calculate the calendar month data, monthly billed sales were adjusted by adding the current month unbilled sales and subtracting the prior month unbilled sales.

The current month unbilled sales are estimated consumptions based on the average daily consumption from the prior bill, and the number of days that not being billed from the prior bill to the last day of the calendar month.

b) Please refer to H-Energy Probe -22 Appendix A for live Excel spreadsheet showing monthly values of the HDD and CDD variables for 2005 through 2014.

**H-Energy Probe-23**

**REF: Ex. H, Tab 1**

Are the LED adjustments shown in Table 13 part of the overall CDN adjustments made and estimated in Exhibit H, Tab 2? If no, please explain why not**.**

**RESPONSE:**

No. The LED adjustments are not part of the overall CDM adjustments made and estimated in Exhibit H, Tab 2. The forecasted CDM savings were developed at a program level, based on average project savings achieved in the 2011-2014 framework. For the Electricity Retrofit Incentive Program, there were no major municipal street lighting LED conversion projects completed in 2011-2014. As such these project types were not explicitly included in the ERII forecast for 2015-2020.

**H-Energy Probe-24**

**REF: Ex. H, Tab 1**

a) Please confirm that the three year average used in relation to the large use rate class is the three year average of the percent change for each of the two customers.

b) Please confirm that the three year average used in relation to the USL rate class is the three year average of the percent change for this class.

**RESPONSE:**

a) & b): Yes.

**H-Energy Probe-25**

**REF: Ex. H, Tab 3 & Appendix H-3-1**

a) Please provide a live Excel spreadsheet that includes all the data used to estimate the residential, GS < 50, GS > 50, sentinel lighting and street lighting rate equations shown in Appendix H-3-1, including all the dependent and independent variables used. Please provide the information used for each rate class on a separate sheet within the live Excel spreadsheet.

b) Please include in the live Excel spreadsheet any independent variables that were included in the various model estimates, but were not included in the final versions of the models.

c) Please include on each sheet within the live Excel spreadsheet, the estimated regression model statistics and the forecasts by month over the 2015 through 2020 period for each of the independent variables and the forecast customers generated by the equation.

**RESPONSE:**

a) Please refer to H-Energy Probe-25 Appendix A for live Excel spreadsheet that includes all the data used to estimate rate equations for Residential, GS < 50 kW, GS > 50 kW, Sentinel Lighting and Street Lighting.

b) Please refer to H-Energy Probe-25 Appendix B for live Excel spreadsheet including all independent variables that were included in the various model estimates, but were not included in the final versions of the models. The detailed results of the model evaluation are also presented in this Appendix.

c) Please refer to H-Energy Probe-25 Appendix C for live Excel spreadsheet including the estimated regression model statistics and the forecasts by month over the 2015 through 2020 period for each of the independent variables and the forecast customers generated by the equation.

**H-Energy Probe-26**

**REF: Appendix H-1-3 & Appendix G-4**

Please provide a table for each of 2016 through 2020 that shows the reconciliation of the kWh's used in the calculation of the cost of power in Appendix G-4 with the figures shown in the various tables in Appendix H-1-3, along with the adjustment for line losses.

**RESPONSE:**

Please refer to H-Energy Probe-26 Appendix A.

**H-VECC-20**

**REF: Ex. H/T-1/ pg. 1**

d) Over the period 2008-2014 used to estimate the models for each rates class, were the meters for each rate class all read at the end of each month?
e) If not, how were the calendar monthly sales data for each class determined?

**RESPONSE:**

d) No. The meters for each rate class were not all read at the end of each month.

e) The calendar monthly sales data for each class were determined based on the actual sales (billed amount) as well as unbilled amount.

**H-VECC-21**

**REF: Ex. H/pg. 3; Appendix H-1-1 and Appendix H-1-2**

a) Please provide a "legend" that explains what the abbreviation in the each of the columns in Appendix H-1-2 stands for.

b) The Proposal states that the historical and forecast saturation values were based on OPA data. Please explain fully what this data is (e.g. is it Power Stream specific or provincial) and how the annual values were derived by the OPA.

c) The Proposal states that the historical efficiency values were based on OPA data. Please explain fully what this data is (e.g. is it Power Stream specific or provincial) and how the annual values were derived by the OPA.

d) The Proposal states the forecast efficiency values reflect improvements in energy efficiency before CDM adjustments. Please explain fully the basis for the efficiency/usage improvements between 2014 and 2020 as predicted for the various uses in Appendix H-1-2.

e) Please indicate the sources for both the historical and forecast values for each of the economic variables in Appendix H-1-1.

f) Please provide a table that summarizes the historical and forecast annual growth rates for each of the economic variables in Appendix H-1-1.

**RESPONSE:**

a) Please see table below for the full description on the abbreviation used in each of the columns in Appendix H-1-2:

| Abbreviation | Description |
|---|---|
| CAC | Central air conditioning |
| RAC | Room air conditioning |
| Dryer | Electric Clothes driers |
| C_Washer | Clothes washing machines |
| Comp | Computers |
| Cook | Electric ovens and cooktops |
| Dehumid | Dehumidifiers |
| D_Washer | Dish washers |
| EWHeat | Electric water heaters |
| Elev | Elevators |
| Airheat | Forced air heating |
| Frz | Freezers |
| Frig | Refrigerators |
| Light | Lighting |
| Misc | Miscellaneous |
| Nonduct_heat | Non-ductal heating |
| Elec | Other Electronic devices |
| SetBox | Cable and satellite boxes |
| SpaceHeat | Space heaters |
| Pool | Pool pumps |
| TV | Televisions |
| Vent_Circ | Ventilation and circulation fans |

b) End-use Saturation represents the share of households in Ontario that owns a given electricity end-use provided in a). A figure of 100% means that all households have that end-use; a figure greater than 100% means that, on average, homes have more than 1 of that end-use. For example, the TV saturation in 2020 of 240.5% means that, on average, a home has 2.4 TVs. The saturation estimates were provided by the former Ontario Power Authority (OPA) and incorporated in the OPA and Ministry of Energy 2013 Long-Term Energy Plan, *Achieving Balance: Ontario's Long-Term Energy Plan (Module 1- Demand Forecast)*.

As per the OPA's correspondence, the annual end-use saturations are projected using an End-Use Forecaster Model (EUF) which generates forecast at the appliance or end-use level. EUF was originally built in 2009 primarily by consultants from Cadmus Inc and ICF Marbek.

The OPA forecast summary presentation which includes a description of the forecasting approach (*LTEP-Module-1-Demand Forecast.pdf, January 2014*) can be downloaded from the OPA website [http://www.powerauthority.on.ca/power-planning/long-term-energy-plan-2013](http://www.powerauthority.on.ca/power-planning/long-term-energy-plan-2013).

c) The historical annual end-use efficiency, measured in unit of energy consumption (UEC), is derived from the End-Use Forecaster Model (EUF). UEC is annual expected kWh usage for a given end-use. EUF tracks appliances, equipment and building stocks over time and simulates technology acquisition in the economy. The data used in EUF to characterize how appliances and equipment use electricity is provincial.

Historical and forecasted UEC were provided by OPA by housing type. The end-use efficiency in kWh are derived by weighing UEC by housing type comprising of single family, multifamily low and high rise, and row houses.

d) The forecast annual end-use efficiency is derived from the End-Use Forecaster Model (EUF). End-use efficiency improvements shown in Appendix H-1-2 are the result of replacing existing appliances with more efficient appliances over time. The data set was provided by OPA and reflects usage trends before adjustments for CDM. The note in figures 3-5 in *Achieving Balance: Ontario's Long-Term Energy Plan*, specifically states that "Intensity is based on gross demand forecast. Opportunity for planned conservation would further reduce electricity intensity".

Having consulted with the OPA with respect to this matter, OPA stated in the email that "The production of the load forecast underlying the LTEP 2013 began with the production of a long term gross demand forecast. The gross demand forecast presents the expected electricity demand before the impacts of codes and standards, conservation policies and programs are considered. It is based in the year 2005."

e) The historical and forecast economic data provided in Appendix H-1-1 is for Toronto Census Metropolitan Areas ("CMA"). Historical and forecasted economic data is provided by the Conference Board of Canada.

f) Please see the table below that summarizes the historical and forecast annual growth rates for each of the economic variables in Appendix H-1-1.

| Year | GDP All Industries (Millions $ 2007) | Annual Growth Rate | GDP Manufacturing (Millions $ 2007) | Annual Growth Rate | Total Population (Thousands ('000s)) | Annual Growth Rate | Real Personal Income per Capita ($, 2002) | Annual Growth Rate |
|---|---|---|---|---|---|---|---|---|
| 2008 | 274,483 | | 39,191 | | 5,505 | | 33,790 | |
| 2009 | 267,470 | -2.6% | 32,678 | -16.6% | 5,591 | 1.6% | 33,407 | -1.1% |
| 2010 | 277,643 | 3.8% | 35,031 | 7.2% | 5,682 | 1.6% | 33,270 | -0.4% |
| 2011 | 284,954 | 2.6% | 36,196 | 3.3% | 5,770 | 1.5% | 33,156 | -0.3% |
| 2012 | 290,838 | 2.1% | 37,074 | 2.4% | 5,870 | 1.7% | 34,187 | 3.1% |
| 2013 | 296,247 | 1.9% | 36,283 | -2.1% | 5,960 | 1.5% | 34,820 | 1.8% |
| 2014 | 303,353 | 2.4% | 37,105 | 2.3% | 6,060 | 1.7% | 34,614 | -0.6% |
| 2015 | 311,784 | 2.8% | 38,389 | 3.5% | 6,165 | 1.7% | 34,670 | 0.2% |
| 2016 | 320,944 | 2.9% | 39,771 | 3.6% | 6,273 | 1.8% | 35,004 | 1.0% |
| 2017 | 329,741 | 2.7% | 41,043 | 3.2% | 6,387 | 1.8% | 35,382 | 1.1% |
| 2018 | 338,346 | 2.6% | 42,151 | 2.7% | 6,504 | 1.8% | 35,769 | 1.1% |
| 2019 | 348,110 | 2.9% | 43,205 | 2.5% | 6,623 | 1.8% | 36,067 | 0.8% |
| 2020 | 358,776 | 3.1% | 44,229 | 2.4% | 6,747 | 1.9% | 36,299 | 0.6% |

**H-VECC-22**

**REF: Ex. H/Appendix H-1-3 – Residential**

a) Was "number of calendar days" evaluated as a possible explanatory variable for Residential usage? If yes, why was it excluded? If not, please provide an evaluation of this potential variable?
b) Please explain why, for the Residential forecast, population, energy intensity and per capital income were all combined together into one single variable.
c) Please provide a schedule that sets out both the historic and forecast values for this "combined" explanatory variable.
d) What would the Residential regression model results (and associated statistics) if the three were separated and each included as a distinct explanatory variable?
e) Please provide a schedule that contrasts PowerStream's Residential energy forecast (prior to CDM adjustments) with the forecast that would result from using the results of part (d).
f) Please explain how, in Table 2, the weather normal historical values for Residential usage were derived.

**RESPONSE:**

a) Yes. The "number of calendar days" was initially included as an explanatory variable in the Residential sales regression model. However, it was ultimately dropped as the variable was statistically insignificant; the T-Statistic was less than 1.

b) Growth in population has a direct impact on Residential sales, and change in household income influences energy consumption behavior and end-use utilization. However, the impact of population and income growth on Residential sales has been declining as end-use efficiencies have been improving. To capture the improvements in efficiency, an intensity trend variable is derived from Ontario Power Authority (OPA) long-term residential end-use forecast.

When per capita income, population, and the efficiency trend variable are added separately the residential sales model shows these variables as statistically insignificant. This is a classic multicolinearity problem that can be solved by using the interactive forecast driver; the interactive variable is highly significant at the 99% level of confidence with a T Statistic of 53.0.

c) Please refer to H-VECC-22 Appendix A for historic and forecast values for this "combined" explanatory variable.

d) Please refer to the table below for Residential regression model statistics, with the three explanatory variables separated and each included as a distinct explanatory variable.

| Model Statistics | |
|---|---|
| Adjusted Observations | 84 |
| Deg. of Freedom for Error | 73 |
| R-Squared | 0.92 |
| Adjusted R-Squared | 0.91 |
| Model Sum of Squares | 178,667,994,819 |
| Sum of Squared Errors | 15,907,614,107 |
| Mean Squared Error | 217,912,522.01 |
| Std. Error of Regression | 14,761.86 |
| Mean Abs. Dev. (MAD) | 11,304.77 |
| Mean Abs. % Err. (MAPE) | 5.24% |
| Durbin-Watson Statistic | 2.066 |

| Variable | Coefficient | StdErr | T-Stat | P-Value |
|---|---|---|---|---|
| mWthr.Res_HDD10 | 143.91 | 10.91 | 13.19 | 0.00% |
| mWthr.Res_CDD18 | 1040.86 | 42.33 | 24.59 | 0.00% |
| mEcon.Pop_Idx | 31754.99 | 87403.27 | 0.36 | 71.74% |
| mEcon.PerCapIncome_Idx | 114783.20 | 123780.19 | 0.93 | 35.68% |
| mEcon.MA_EI | 27086.34 | 44605.69 | 0.61 | 54.56% |
| mBin.Jan08 | 87604.76 | 16044.47 | 5.46 | 0.00% |
| mBin.Feb08 | -37151.34 | 15887.60 | -2.34 | 2.21% |
| mBin.Nov10 | -29072.74 | 16136.62 | -1.80 | 7.57% |
| mBin.Jun14 | -54514.48 | 15190.32 | -3.59 | 0.06% |
| mBin.Nov | -17344.84 | 6707.37 | -2.59 | 1.17% |
| mBin.Dec | 20778.85 | 6026.40 | 3.45 | 0.09% |

e) Please refer to the table below for comparison on the load forecast result (kWh) under the two methods, prior to CDM adjustments:

| Year | Residential Energy Forecast Rate Proposal | Residential Energy Forecast Using results of part (d) | Difference |
|---|---|---|---|
| **2015** | 2,751,918 | 2,759,097 | 7,179 |
| **2016** | 2,762,437 | 2,770,957 | 8,520 |
| **2017** | 2,771,455 | 2,784,394 | 12,939 |
| **2018** | 2,795,225 | 2,800,288 | 5,063 |
| **2019** | 2,825,613 | 2,814,410 | - 11,204 |
| **2020** | 2,851,779 | 2,826,059 | - 25,720 |

f) Weather normalized Residential sales are derived using the estimated residential sales model. The estimated model is used to predict monthly sales for normal weather conditions using the MetrixND Simulation Object.

In the Simulation Object actual HDD are replaced with normal HDD and actual CDD are replaced with normal CDD. When executed, the Simulation Object returns the predicted monthly sales for normal weather conditions given the estimated model coefficients.

Monthly results represent expected calendar month sales for normal weather conditions.

**H-VECC-23**

**REF: Ex. H/Appendix H-1-3 – GS<50 and GS>50**

a) Was "number of peak days" evaluated as a possible explanatory variable for both the GS<50 and GS>50 models? If yes, why was it excluded in each case? If not, please provide an evaluation of this potential variable for each of the two classes?

**RESPONSE:**

No. After further clarification we understand that the question was whether we included the number of week-days (excluding holidays) as explanatory variables in GS< 50 kW and GS > 50 kW models. As requested, we re-estimated both models with a "number of peak days" variable.

In the GS< 50 kW model, the "peak-day" variable proved to be statistically significant with a T Statistic of 2.06; the addition of the variable slightly improves the overall model fit with the Adjusted R-Squared increasing from 0.880 to 0.885. The coefficient on the explanatory variable *(GDP_Idx*) is slightly lower and as a result the sales forecast is slightly lower when the "peak-day" variable is added. The impact on the forecast is minimal; with the peak-day variable, the sales forecast is slightly lower.

In the GS> 50 kW model the "peak-day" variable is marginally significant (at the 85% level of confidence with a T Statistic of 1.55). The "peak-day" variable slightly improves the in-sample model fit with the Adjusted R-Squared improving from 0.844 to 0.847. Again the coefficient on the manufacturing GDP driver (*ManGDP_Idx*) forecast driver is slightly lower resulting in a slightly lower sales forecast.

The model results with the "peak-day" variable are summarized below:

## Model Stats - GS<50 kW

| Model Statistics | |
|---|---|
| Iterations | 1 |
| Adjusted Observations | 84 |
| Deg. of Freedom for Error | 75 |
| R-Squared | 0.90 |
| Adjusted R-Squared | 0.89 |
| Model Sum of Squares | 5,495,153,738 |
| Sum of Squared Errors | 640,289,017 |
| Mean Squared Error | 8,537,187 |
| Std. Error of Regression | 2,922 |
| Mean Abs. Dev. (MAD) | 2,224 |
| Mean Abs. % Err. (MAPE) | 2.61% |
| Durbin-Watson Statistic | 2.254 |

| Variable | Coefficient | StdErr | T-Stat | P-Value |
|---|---|---|---|---|
| mWthr.SmlGS_HDD10 | 41.82 | 2.488 | 16.809 | 0.00% |
| mWthr.SmlGS_CDD18 | 158.74 | 9.694 | 16.375 | 0.00% |
| mEcon.GDP_Idx | 18,760.06 | 6461.22 | 2.903 | 0.48% |
| mWthr.CalDays | 1,243.57 | 336.842 | 3.692 | 0.04% |
| mWthr.Peakdays | 788.17 | 382.579 | 2.06 | 4.29% |
| mBin.Jan08 | 21,837.98 | 3020.311 | 7.23 | 0.00% |
| mBin.Feb08 | - 9,731.91 | 2987.79 | -3.257 | 0.17% |
| mBin.Oct | - 3,367.58 | 1279.815 | -2.631 | 1.03% |
| mBin.Dec | 8,711.92 | 1259.26 | 6.918 | 0.00% |

## Model Stats – GS> 50 kW

| Model Statistics | |
|---|---|
| Iterations | 1 |
| Adjusted Observations | 84 |
| Deg. of Freedom for Error | 71 |
| R-Squared | 0.87 |
| Adjusted R-Squared | 0.85 |
| Model Sum of Squares | 57,209,002,365 |
| Sum of Squared Errors | 8,609,029,961 |
| Mean Squared Error | 121,253,943 |
| Std. Error of Regression | 11,012 |
| Mean Abs. Dev. (MAD) | 7,445 |
| Mean Abs. % Err. (MAPE) | 2.00% |
| Durbin-Watson Statistic | 1.92 |

| Variable | Coefficient | StdErr | T-Stat | P-Value |
|---|---|---|---|---|
| mWthr.LrgGS_HDD10 | 48.766 | 8.857 | 5.506 | 0.00% |
| mWthr.LrgGS_CDD18 | 367.344 | 34.543 | 10.634 | 0.00% |
| mEcon.ManGDP_Idx | 122260.032 | 24834.4 | 4.923 | 0.00% |
| mWthr.CalDays | 6519.121 | 1202.622 | 5.421 | 0.00% |
| mWthr.Peakdays | 2206.631 | 1436.887 | 1.536 | 12.91% |
| mBin.Jan08 | -111697.552 | 11496.11 | -9.716 | 0.00% |
| mBin.Feb08 | 129865.938 | 11749.3 | 11.053 | 0.00% |
| mBin.Sep10 | -45192.036 | 11216.18 | -4.029 | 0.01% |
| mBin.May11 | 42934.422 | 11248.65 | 3.817 | 0.03% |
| mBin.Jun11 | -52645.913 | 11970.81 | -4.398 | 0.00% |
| mBin.Dec13 | 43652.123 | 11313.19 | 3.859 | 0.03% |
| mBin.Nov14 | 33302.308 | 11250.35 | 2.96 | 0.42% |
| mBin.Jun | 14050.139 | 4900.812 | 2.867 | 0.55% |

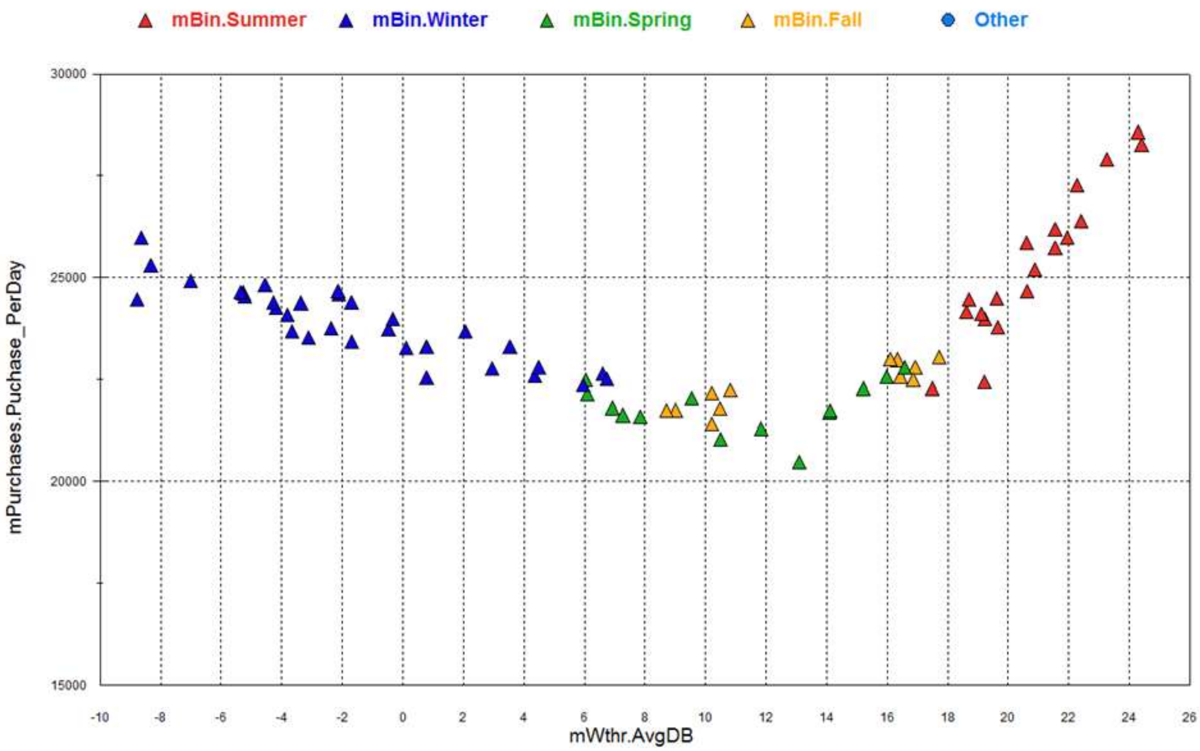
**H-VECC-24**

**REF: Ex. H/T-1/pg. 4**

a) The Proposal states that PowerStream "found that cooling-related demand began when temperatures exceeded 18 degrees and heating-related demand began when temperatures fell below 10 degrees". What is the basis for this statement?

**RESPONSE:**

a) The breakpoints can be seen by examining a scatter plot that shows daily average purchase against average daily temperature. As shown in the Figure below, cooling load begins where average temperature is above 18 degrees and heating load can be seen with average temperature below 10 degrees.



**H-VECC-25**

**REF: Ex. H/Appendix H-1-3 – Sentinel & Street Lighting**

a) Please explain why only certain months were included as explanatory variables for the Sentinel Light and Street Lighting models. Were all months tested as potential explanatory variables in each case?
b) Are all of the Street Lights in Power Stream's service area currently HPS? If not, what is the make-up by type as of December 2014?
c) What percentage of the total street lights (i.e., devices) in Power Stream's service are currently HPS lights owned by Vaughan, Barrie or Markham?

**RESPONSE:**

a) We tested all the monthly binaries as potential explanatory variables for the Street Lighting and Sentinel Lighting models.

For Street Lighting model, the selected monthly binaries proved to give the best overall model fit. When all months are added as explanatory variables, the Street Lighting sales models show all monthly variables are statistically insignificant. The table below shows the model statistics with all months included as explanatory variables:

| Model Statistics | |
|---|---|
| Iterations | 1 |
| Adjusted Observations | 84 |
| Deg. of Freedom for Error | 65 |
| R-Squared | 0.838 |
| Adjusted R-Squared | 0.793 |
| Model Sum of Squares | 201,451,756.46 |
| Sum of Squared Errors | 38,881,620.16 |
| Mean Squared Error | 598,178.77 |
| Std. Error of Regression | 773.42 |
| Mean Abs. Dev. (MAD) | 463.26 |
| Mean Abs. % Err. (MAPE) | 9.98% |
| Durbin-Watson Statistic | 2.384 |

| Variable | Coefficient | StdErr | T-Stat | P-Value |
|---|---|---|---|---|
| CONST | 16720.908 | 17521.72 | 0.954 | 34.35% |
| mWthr.HrLight | -33.846 | 62.862 | -0.538 | 59.21% |
| mBin.Nov08 | -2952.039 | 847.767 | -3.482 | 0.09% |
| mBin.Apr09 | -2618.584 | 835.412 | -3.134 | 0.26% |
| mBin.Feb10 | -2606.071 | 865.094 | -3.012 | 0.37% |
| mBin.Nov12 | -4536.494 | 847.799 | -5.351 | 0.00% |
| mBin.Dec12 | 4632.829 | 835.4 | 5.546 | 0.00% |
| mBin.Jan | -268.569 | 835.043 | -0.322 | 74.88% |
| mBin.Feb | -1067.451 | 1270.359 | -0.84 | 40.38% |
| mBin.Mar | 816.178 | 5784.804 | 0.141 | 88.82% |
| mBin.Apr | 2566.914 | 7863.628 | 0.326 | 74.52% |
| mBin.May | 3010.317 | 11200.92 | 0.269 | 78.90% |
| mBin.Jun | 1741.592 | 11506.21 | 0.151 | 88.02% |
| mBin.Jul | 2024.742 | 11834.19 | 0.171 | 86.47% |
| mBin.Aug | 2315.711 | 9644.442 | 0.24 | 81.10% |
| mBin.Sep | 374.699 | 6061.381 | 0.062 | 95.09% |
| mBin.Oct | -144.36 | 3943.038 | -0.037 | 97.09% |
| mBin.Nov | -913.443 | 881.609 | -1.036 | 30.40% |
| mBin.Dec | 0 | 0 | 0 | 100.00% |

Similarly, for Sentinel Lighting, only those months that were statistically significant at 98% or higher level of confidence were left in the model specifications.

b) No. 88% of the Street Lights are HPS and 12% are LED as of December 2014.

c) Vaughan: 22%
Barrie: 13%
Markham: 18%

**H-VECC-26**

**REF: Ex. H/T-1/pg. 6**

**E-H/T-2/pg. 2-3 and Appendix 2-I**

a) Please provide a copy of the OPA's (now IESO's) final CDM evaluation for 2013.
b) Is Table 2 (E-H/Tab 2) based on PowerStream's 535 GWh target or its CDM submission to the IESO?
c) Please provide the equivalent of Table 2 but where each year's CDM is the full "annualized" impact of the CDM programs.
d) Power Stream claims that it has used the ½ year rule for first year's savings attributed to its future CDM programs. However, in Tab 2, Table 2, the first year saving used for 2016, 2017, 2018, 2019 and 2020 programs are all more than 50% of the savings attributed in to the programs in subsequent years (e.g.., for 2017 CDM programs the first year's savings are 43,861,543 kWh and the following years' savings are 66,489,632 kWh). Please reconcile and correct Table 2 and the subsequent load forecast as required.
e) With respect to the 2015 LRAMVA GWhs reported in Appendix 2-I, please confirm that this is based on the ½ of the forecast impact of 2015 CDM programs in 2015. If affirmed, please confirm that PowerStream is not proposing to base its 2015 LRAMVA calculation on the actual annualized CDM results as will be reported by the IESO but rather ½ of this value.

**RESPONSE:**

a) Please refer to H-VECC-26 Appendix A for the 2013 final CDM evaluation report issued by the former OPA.

b) Yes. Table 2 (E-H/Tab 2) is based on PowerStream's CDM target of 535 GWh submitted to the IESO.
c) Please refer to the table below for the equivalent of Table 2 (E-H/Tab 2) but where each year's CDM is the full "annualized" impact of the CDM programs.

| 6 Year (2015-2020) kWh Target: | | | | | | | |
|---|---|---|---|---|---|---|---|
| 535,500,000 kWh | | | | | | | |
| | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **Total** |
| 2015 CDM Programs | 3.16% | | | | | | 3.16% |
| 2016 CDM Programs | | 3.96% | | | | | 3.96% |
| 2017 CDM Programs | | | 5.32% | | | | 5.32% |
| 2018 CDM Programs | | | | 8.23% | | | 8.23% |
| 2019 CDM Programs | | | | | 8.43% | | 8.43% |
| 2020 CDM Programs | | | | | | 8.61% | 8.61% |
| **Total in Year** | **3.16%** | **3.96%** | **5.32%** | **8.23%** | **8.43%** | **8.61%** | **37.71%** |
| **kWh** | | | | | | | |
| 2015 CDM Programs | 52,078,087 | 52,078,087 | 52,078,087 | 52,078,087 | 51,351,325 | 51,351,325 | 311,014,998 |
| 2016 CDM Programs | | 65,205,351 | 61,770,326 | 61,770,326 | 61,770,326 | 61,043,564 | 311,559,892 |
| 2017 CDM Programs | | | 87,723,086 | 66,489,632 | 66,489,632 | 66,489,632 | 287,191,982 |
| 2018 CDM Programs | | | | 135,584,304 | 107,183,019 | 107,183,019 | 349,950,343 |
| 2019 CDM Programs | | | | - | 138,899,626 | 107,495,108 | 246,394,734 |
| 2020 CDM Programs | | | | - | - | 141,937,351 | 141,937,351 |
| **Total in Year** | **52,078,087** | **117,283,438** | **201,571,499** | **315,922,349** | **425,693,929** | **535,500,000** | **1,648,049,301** |

d) Further to the response provided in c), the ½ year rule impacts on the first year CDM savings were incorporated in the table below, in purple font, which ties back to Table 2 (E-H/Tab 2).

| 6 Year (2015-2020) kWh Target: | | | | | | | |
|---|---|---|---|---|---|---|---|
| 535,500,000 kWh | | | | | | | |
| | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **Total** |
| 2015 CDM Programs | 52,078,087 | 52,078,087 | 52,078,087 | 52,078,087 | 51,351,325 | 51,351,325 | 311,014,998 |
| **1/2 year rule** | **26,039,043** | | | | | | **284,975,955** |
| 2016 CDM Programs | | 65,205,351 | 61,770,326 | 61,770,326 | 61,770,326 | 61,043,564 | 311,559,892 |
| **1/2 year rule** | | **32,602,676** | | | | | **278,957,217** |
| 2017 CDM Programs | | | 87,723,086 | 66,489,632 | 66,489,632 | 66,489,632 | 287,191,982 |
| **1/2 year rule** | | | **43,861,543** | | | | **243,330,440** |
| 2018 CDM Programs | | | | 135,584,304 | 107,183,019 | 107,183,019 | 349,950,343 |
| **1/2 year rule** | | | | **67,792,152** | | | **282,158,191** |
| 2019 CDM Programs | | | | | 138,899,626 | 107,495,108 | 246,394,734 |
| **1/2 year rule** | | | | | **69,449,813** | | **176,944,921** |
| 2020 CDM Programs | | | | | | 141,937,351 | 141,937,351 |
| **1/2 year rule** | | | | | | **70,968,675** | **70,968,675** |
| **Total in Year** | **52,078,087** | **117,283,438** | **201,571,499** | **315,922,349** | **425,693,929** | **535,500,000** | **1,648,049,301** |
| **1/2 year rule** | **26,039,043** | **84,680,763** | **157,709,956** | **248,130,197** | **356,244,116** | **464,531,325** | **1,337,335,399** |

Each CDM program has an average persistence in terms of the length of time and the energy savings persist from the time they were realized. Behavior programs, such as Dynamic Pricing and Home Energy Reports, typically have a shorter persistence about one year. The bigger variances beginning 2017 mainly because these behavior based programs are ramped up, resulting in greater "drop offs" in the year after installation, at a portfolio level.

e) As illustrated in the response in d), the 2015 CDM savings reported in Appendix 2-I is based on the ½ of the forecast impact of 2015 CDM programs in 2015. It is the base and used as an offset to our load forecast. In calculating the 2015 LRAMVA, PowerStream uses the actual CDM savings achieved and verified by the IESO for 2015 and adjusts these values using the ½ year rule for CDM programs in 2015 before comparing to the CDM reductions used to set rates.

**H-VECC-27**

**REF: Ex. H/T-4/pg. 1 and Appendix H-1-3**

a) Please explain how the kW billing determinant forecasts for the GS>50, Large Use, Street Lighting and Sentinel Lighting classes were derived from the GWh forecasts for each class as set out in Appendix H-1-3.

**RESPONSE:**

a) The kW billing determinant forecasts for the GS > 50 kW, Large Use, Street Lighting and Sentinel Lighting classes were derived from the GWh forecasts based on a 3-year average historical relationship between kW and kWh for each class as set out in the table below:

| Year | GS>50 kW | Large Use | Street Lighting | Sentinel Lighting |
|---|---|---|---|---|
| **2012** | 0.27% | 0.20% | 0.27% | 0.26% |
| **2013** | 0.27% | 0.21% | 0.28% | 0.26% |
| **2014** | 0.27% | 0.19% | 0.29% | 0.26% |
| **3 Year Average** | **0.27%** | **0.20%** | **0.28%** | **0.26%** |
| **2015-2020** | **0.27%** | **0.20%** | **0.28%** | **0.26%** |

## EXHIBIT I: REVENUE OFFSETS

**I-CCC-50**

**REF: Ex. I/T1/p. 1**

With respect to Specific Service Charges has PowerStream done any studies to determine whether the level of these charges is reflective of the cost of providing these services?  If not, why not?

**RESPONSE:**

Please see response to I-EP-30.

**I-CCC-51**

Please provide PowerStream's written policy regarding pole rentals. Does PowerStream intend to apply for Board approval to charge market based rates for wireless pole attachments?

**RESPONSE:**

See attached appendices I-CCC-51 Appendix A and I-CCC-51 Appendix B for PowerStream's policies and procedures.

PowerStream does not intend to apply for Board approval to charge market based rates for wireless pole attachments at this time.

**I-CCC-52**

**REF: Ex. I/T1/p. 1**

Please provide a detailed breakdown of “Other Distribution Revenues” for each year 2013-2020.

**RESPONSE:**

The components of “Other Distribution Revenue” are as follows:

Account 4078 is Standard Supply Service (“SSS”) Administration charges; these revenues are attributable to an administrative charge of $0.25 per customer per month.

Account 4082 is Retail Services Revenue, this account relates to billing services that PowerStream provides to its retailers.

Account 4210 is rent from Electric Property; this account relates to fees that PowerStream charges third parties to install apparatus onto poles. The fee is based on the Board’s standard rate of $22.35/pole/year.

Account 4245 relates to the amortization of Contributed Capital. This amount is removed from other distribution revenue (as this is considered part of the amortization of fixed assets) and is captured here for rate modelling.

A detailed breakdown of “Other Distribution Revenue” is outlined in the table below:

| USoA # | USoA Description | 2013 Board-Approved* | 2013 Actuals | 2014 Actuals | Bridge Year[3] | TEST YEAR 1 | TEST YEAR 2 | TEST YEAR 3 | TEST YEAR 4 | TEST YEAR 5 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Other Distribution Revenue (000’s)** | | | | | | | | | | |
| 4078 | SSS Administration Charge | 932 | 968 | 996 | 1,014 | 1,033 | 1,051 | 1,070 | 1,090 | 1,110 |
| 4082 | Retail Services Revenues | 400 | 235 | 212 | 216 | 220 | 224 | 228 | 232 | 236 |
| 4210 | Rent from Electric Property | 700 | 744 | 757 | 746 | 748 | 750 | 748 | 749 | 749 |
| 4245 | Government & Other Assistance Directly Credited to Income | - | 1,887 | - | - | - | - | - | - | - |
| 4245 | Government & Other Assistance Directly Credited to Income | - | (1,887) | - | - | - | - | - | - | - |
| **Sub total** | | **2,032** | **1,947** | **1,965** | **1,976** | **2,001** | **2,025** | **2,046** | **2,071** | **2,095** |

**I-Energy Probe-27**

**REF: Ex. I, Tab 1**

The evidence states that the inclusion of joint service revenue is not consistent with the approach taken in PowerStream's 2013 cost of service application because in 2013 only margin earned on joint services provided was included in other income and that going forward PowerStream is including all of the joint service revenue in other operating revenue and all joint services costs in OM&A.

a) Please show where in Table 2 this change and the revenues and costs associated with the joint service revenue is located.

b) For each of 2013 Board approved through to 2020, please provide a table that shows total joint service revenues and the costs associated with these revenues.

**RESPONSE:**

a) Before 2013 the revenues and expenses associated with the joint services revenue were recorded in account 4375 and 4380 respectively. Account 4375 is revenues from non-rate-regulated utility operations and account 4380 is expenses from non rate-regulated utility operations. In the 2013 rate application the net amount of joint services revenue and costs was added to Other Operating Revenue. After 2013, joint service revenue was still booked in account 4375, but the joint services costs were included in a number of OM&A accounts and no longer reallocated to account 4380. Netting of the revenues and costs is not allowed under IFRS and therefore only joint services revenue has been included in Other Operating Revenue.

b) Table 1 below separates out joint service revenue and costs for the 2013 Board approved to the 2020 test year.

**Table 1: Summary of Joint Service Revenues and Costs**

| | **Board Approved** | **Actual** | | **Bridge Year** | **TEST YEAR 1** | **TEST YEAR 2** | **TEST YEAR 3** | **TEST YEAR 4** | **TEST YEAR 5** |
|---|---|---|---|---|---|---|---|---|---|
| | **2013** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
| Revenue | (3,201) | (3,065) | (2,945) | (3,057) | (3,148) | (3,243) | (3,340) | (3,440) | (3,544) |
| Cost | 2,941 | 2,856 | 2,728 | 2,849 | 2,934 | 3,022 | 3,113 | 3,206 | 3,303 |

**I-Energy Probe-28**

**REF: Ex. I, Tab 1, Table 2**

a) Please explain what revenues and costs are shown in the second set of accounts 4375 and 4380 that offset part of the revenues shown in the first 4375 reference and offset the costs shown in the first 4380 reference shown in the table.

b) Please explain what is recorded in each of accounts 4355, 4362, 4385 and 4420.

c) For each account noted in part (b) above, please explain why the associated revenues (or costs) have been removed from the bottom line.

d) Please explain the decrease in account 4390 shown between 2015 and 2016 and 2017, the increase in 2018 and the subsequent decrease in 2019 and 2020.

**RESPONSE:**

a) There are two areas in the Other Operating Income section in Exhibit 1 tab 1 Table 2 that references account 4375 and 4380. The first set of accounts in table 2 of Exhibit 1, tab 1 is 4375 (revenues from non rate-regulated utility operation) and 4380 (expenses from non rate-regulated utility operation). These accounts show the total revenue and cost included in PowerStream's general ledger accounts. They include revenues and costs that are not part of the revenue requirement and rate setting parameters.

The second set of account 4375 and 4380 in table 2 of Exhibit 1, tab 1 are revenues and cost adjustments that are excluded from the revenue requirement or rate setting parameters.

The net of these four rows in the table is the revenue from non-rate regulated activities that should be considered for rate setting purposes.

The breakdown of what is included in 4375 and 4380 is set out below. The revenues in these accounts are mainly attributable to CDM related activity which is funded from the IESO. The amounts in these accounts are not part of the distribution business; they are funded from other sources and therefore are removed from the other revenue account. The difference between 4375 and its related offset is joint service revenue which is now being included in other operating revenue.

| **Account 4375** | **Y2013 Actual** | **Y2014 Actual** |
|---|---:|---:|
| CDM Related | 20,001,187.90 | 24,197,602.40 |
| Fibre Revenue | 17,857.20 | 17,857.20 |
| Solar Micro-FIT & Others | 98.14 | 1.72 |

| | | |
|---|---|---|
| **Total 4375** | **23,653,392.08** | **27,719,175.53** |
| **Total 4375 offset** | **-20,019,143.24** | **-24,215,457.88** |
| Difference between 4375 and 4375 offset is joint services | -3,634,248.84 | -3,503,717.65 |
| Account 4380 - CDM related | 19,955,141.00 | 24,140,021.00 |

b) Account 4355 “Gain on disposition of utility and other property” includes gains or losses on asset disposal; this is mainly made up of the sale of vehicles and meters. Account 4362 “Loss on disposition of utility and other property” includes the loss on disposals/derecognition from hydro poles, underground transformer, overhead transformer, switches and switchgears. Account 4385 “Non rate-regulated utility rental income” includes sentinel light rental charges. Account 4420 “Share of Profit and loss from joint venture” includes 50% of the profit of PowerStream Collus Inc. PowerStream owns a 50% share of PowerStream Collus Inc.

c) The accounts in b) are removed from other operating revenue for two reasons. Amounts recorded in these accounts are either reclassed or restated in other areas, or activities recorded in the revenue accounts are not related to distribution services. Amounts recorded in account 4362 have been moved and restated for rate setting purposes as depreciation expense. Revenues recorded in accounts 4385 and 4420 are not related to distribution services. Revenues in account 4420 represent 50% of PowerStream’s share in PowerStream Collus Inc., and 4385 is the rental income from PowerStream Solar. Revenues in account 4355 should be part of other operating revenues considered in the rate setting process and it was a clerical error to exclude it in Exhibit I, Tab 1 Table 2.

d) In account 4390 “Miscellaneous non-operating income”, the 2015 budget was based on the historic average of 2012, 2013 actuals and 2014 forecast. The 2016 budget was based on the average of 2013, 2014 and 2015 actual, forecast or budget amounts; the same assumption goes for every year for the rest of the years 2017 to 2020, which is why there is a small fluctuation in each year. Please see the chart below for values used to forecast these amounts. The historic average was adjusted for one time revenues in 2012, 2013 and 2014. Examples of these one-time amounts in 2014 include a $600,000 surplus in health and dental benefits which was a direct result of changing carriers, and the insurance claim received for $767,000 as a result of an assessment conducted in relation to a loss of assets.

| Account 4390 | ($M) | | ($M) |
|---|---|---|---|
| Y2012 actual exclude one time | 1.227 | Y2016 forecast | 1.079 |

| | | | |
|---|---|---|---|
| Y2013 actual exclude one time | 1.170 | Y2017 forecast | 1.049 |
| Y2014 forecast at budget time | 0.951 | Y2018 forecast | 1.081 |
| Y2014 actual | 1.114 | Y2019 forecast | 1.069 |
| Y2015 forecast | 1.116 | Y2020 forecast | 1.037 |

**I-Energy Probe-29**

**REF: Ex. I, Tab 1**

a) Which account shown in Table 2 includes revenues from microfit and fit customers?

b) Please provide the actual and forecasted revenues from these customers in 2013 through 2020, along with the average number of customers in each year.

c) If the number of customers shown in the response to part (b) above differ from the numbers in the Distribution System Plan, please explain.

**RESPONSE:**

a) Account 4235 Specific Service Charges in Table 2 includes revenues from microfit and fit customers for the period 2013-2014. In 2015, revenue from fit customers is recorded as distribution revenue in account 4080 Distribution Services Revenue. The change was made to better reflect revenue from FIT customers as they are charged distribution rates and therefore should not be included in other revenue. Revenue from microfit customers continues to be booked to 4235, Specific Service Charges.

b) The microfit actual and forecasted revenues from 2013 to 2020 are included in the table below, as well as the average number of customers per year. As noted in the answer to part (a), in 2015 the fit customer revenue was moved to distribution revenue.

| ($) | Account | 2013 Board Approved | 2013 Actual | 2014 Actual | 2015 Bridge | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|
| Micro-FIT Monthly Service Charge | 4235 | 0 | 21,279 | *32,508* | *31,713* | *32,348* | *32,994* | *33,654* | *34,327* | *35,014* |
| FIT Monthly Service Charge - (charge per load, move to 4080 in 2015) | 4235 | 0 | 9,606 | *12,560* | *12,033* | | | | | |
| Average Number of Customers | | | 2,745 | *3,031* | *3,245* | *3,467* | *3,527* | *3,587* | *3,587* | *3,587* |

c) The number of customers shown in the response to part (b) above is the same as the numbers in the Distribution System Plan.

**I-Energy Probe-30**

**REF: Ex. I, Tab 1, page 1**

The evidence indicates that PowerStream is not proposing to change any of the specific service charges during the term of the Custom IR.

a) Has PowerStream done any analysis of the costs to provide these services to determine if the revenues generated are covering the costs incurred in providing the services? If yes, please provide details.

b) Has PowerStream considered increasing the charges each year for the specific service charges to at least cover part of the increase associated with inflation and wage increases? If not, why not?

c) Are the costs incurred to provide the specific services mainly associated with labour costs?

**RESPONSE:**

a) PowerStream has not done an analysis of the cost providing these services.

b) PowerStream has not considered increasing the charges each year for the specific service charges to at least cover part of the increase associated with inflation and wage increase. PowerStream accepted the Board-established default rates as reasonable.

c) PowerStream has based this response on the cost methodology and the cost components for the specific service charge as per the 2006 Electricity Distribution Rate Handbook. Elements of the calculation for each charge include the following:

- direct labour (internal and/or external)
- labour rate (internal and/or external)
- burden rate
- incidental (e.g. postage for mail)
- vehicle time and rate (if applicable).

On this basis, it is concluded that the costs incurred to provide most specific services have labour costs as a significant component.

**I-Energy Probe-31**

**REF: Ex. I, Tab 1, page 1**

In the EB-2014-0002 Settlement Proposal with Horizon Utilities Corporation, it was agreed that:

*"Horizon Utilities will retain an external consultant to conduct a study of its Specific Service Charges for the purposes of determining appropriate levels of charges. The intention of the study is to ensure that the charges incorporate the costs of providing the services and avoid, to the extent possible, subsidization of customers who are subject to such charges by those customers who are not. The Parties have agreed that Horizon utilities will consult with intervenor representatives in the current proceeding in establishing the Terms of Reference for the study. Horizon Utilities agrees to explore opportunities to collaborate with other utilities on the study including the sharing of costs. The Parties have further agreed that Horizon Utilities may recover up to $250,000 for the study (including related intervenor costs) as part of its next rebasing application. Those costs will be tracked in a deferral account with the balance (not to exceed $250,000) to be disposed of at the time of Horizon Utilities' next rebasing. Horizon Utilities proposes to record the costs in Account 1508 Other Regulatory Assets and requests a new 1508 Sub-account "Special Studies" to segregate these costs. The Parties have agreed that any proposed changes to Specific Service Charges arising out of the study will be addressed as part of Horizon Utilities' next rebasing application."*

Would PowerStream agree to a similar arrangement?  If not, please explain why not.

**RESPONSE:**

Yes, PowerStream would agree to a similar arrangement.

**I-Energy Probe-32**

**REF: Ex. J, Tab 1, Appendix I-1-1**

a) Are the figures shown for each of the years in Appendix I-1-1for Strategic Support, Finance and Legal support from PowerStream to PowerStream Holdings Inc. revenues received by PowerStream for the provision of services to Holdings?

b) Are the figure shown for each of the years in Appendix I-1-1 for Board of Directors, Directors Insurance and Audit Costs, costs that are recovered from PowerStream by Holdings?

c) Are the Board of Director costs associated with the PowerStream Board of Directors or the PowerStream Holdings Inc. Board of Directors?

d) Are the figures noted in parts (a) and (b) above included in the calculation of the revenue requirement in each of the test years?

e) How are the allocation percentages used calculated?

**RESPONSE:**

Preamble:

In order to answer the questions above, the background of PowerStream Holdings should be explained; PowerStream Holdings allocates costs to PowerStream Inc. and PowerStream Energy Services Inc. There is only one Board of Directors which resides at PowerStream Holdings, therefore costs incurred for Board of Directors are allocated to PowerStream Inc. and PowerStream Energy Services Inc based on an allocation methodology. Other direct costs incurred by PowerStream Holdings (i.e. audit costs) are also allocated down to both PowerStream Inc. and PowerStream Energy Services.

a) The figures shown for each of the years in Appendix I-1-1 for strategic support, finance and legal support from PowerStream Inc., to PowerStream Holdings are not revenues received by PowerStream Inc., but “cost allocations” out of PowerStream Inc OM&A to PowerStream Holdings OM&A.

b) The figures shown in Appendix I-1-1 for Board of Directors, Directors Insurance and audit costs are direct costs that are incurred by PowerStream Holdings which then get allocated back to PowerStream Inc. and PowerStream Energy Services.

c) The Board of Directors costs are incurred by PowerStream Holdings and then gets allocated back to PowerStream Inc. The allocation of costs to PowerStream Inc., represents the percentage of time spent by the PowerStream Holdings Board of Directors on matters related to PowerStream Inc.

d) The figures in part (a) and (b) that relate to PowerStream Inc. are included in the calculation of revenue requirement for each of the test years.

e) The allocation percentages are calculated based on two methodologies. The Board of Director costs (labour and other expenses) are allocated based on percentage of time spent by the PowerStream Holdings Board of Directors on matters related to PowerStream Inc., versus PowerStream Energy Services Inc. The basis for this allocation was developed based on PowerStream Holdings Inc., Board agenda items and minutes from meetings. Other direct costs (such as audit costs) are allocated based on the percentage of OM&A. This was derived based on a calculation which compared the Distribution business OM&A proportional to the total PowerStream OM&A (PowerStream Inc., OM&A and PowerStream Energy Services OM&A).

**I-SEC-38**

**REF: Ex. I-1-1**

Please explain how PowerStream forecasted its 2016-2020 Other Operating Revenues.

**RESPONSE:**

The 2016-2020 Other Operating Revenues are forecasted based on historical trends using an average of three historical years unless there is a contract or specific term, then the forecast will be based on a contract or the terms specified. Each category of Other Operating revenue and the forecasting method is described below.

Specific charges are forecasted mostly based on an average of three historical years; the only exception is revenue for microfit customers which are based on a 2% year over year increase. This is because growth is anticipated for microfit customers in the next few years and will level off after 2018.

The 2016-2020 forecasted revenue from late payment charges is developed using an average of three of the prior years. For example the 2016 forecast year of $2.038M is calculated from the average of revenue values from Y2015, Y2014 and Y2013. The chart below shows the actuals and the forecast years used for the test years assumptions. 2016 to 2020 is lower based on the 2013 year being lower , bringing down the average.

| Late Payment | ($M) | | ($M) |
|---|---|---|---|
| Y2010 actual | 2.457 | Y2015 forecast | 2.022 |
| Y2011 actual | 2.184 | Y2016 forecast | 2.038 |
| Y2012 actual | 1.973 | Y2017 forecast | 2.077 |
| Y2013 actual | 1.923 | Y2018 forecast | 2.046 |
| Y2014 actual | 2.183 | Y2019 forecast | 2.054 |
| Y2014 forecast at budget time | 2.169 | Y2020 forecast | 2.059 |

Some parts of the other distribution revenue is forecasted using the same methodology as noted above, using an average of the three prior years. Standard Supply Service Charge (account 4078) and Retail Charges (account 4082) forecasts are derived by multiplying forecasted customer counts by the charge per customer.

Other Income and Deductions is developed using an average of three of the prior years, excluding any one time charges. Joint Service revenue is forecasted with a 3% increase year over year, as the contract states.

**I-SEC-39**

**REF: Ex. I-1-1, Appendix 2**

A number of shared services between PowerStream and its affiliates uses a "[f]ully allocated costs w. markup" pricing methodology. Please explain how the markup for these services is determined. Please also explain why some services are provided on a fully allocated basis without markup.

**RESPONSE:**

For the marked up services included in I-1-1 Appendix 2, the mark up was based on the Joint Services contract for Vaughan and Markham developed using the OEB approved rate of return of 7.3% at the time of the shared service agreement was established. The contract incorporates a 3% increase in fees each year.

In relation to the fully allocated costs, these include both Collus PowerStream Inc., and PowerStream Holdings Inc contracts. For Collus PowerStream there was a mistake made in the Shared services schedules, the schedule indicated that they are fully allocated without markup, however there is a mark-up of 6% applied and it is based on the Cost of Capital Rate of Return.

For PowerStream Holdings Inc., these costs do not include a mark-up, they are allocated back to PowerStream Inc. These costs are fully allocated without markup because including a mark-up is not in compliance with Article 340 of the Accounting Procedures Handbook and in the Board's *"Guidelines: Regulatory and Accounting Treatments for Distributor-owned Generation Facilities", September 15, 2009,* which discusses the guidelines for the proper cost allocation methods for non-rate regulated activities. It states that there should not be cross-subsidies between regulated and non-regulated activities.

**I-VECC-28**

**REF: Ex. I/pg. 2**

a) Please explain why, for each of the years 2016-2020, the forecasted revenues from Late Payment Charges are less than the actual revenues in 2014.
b) Please explain why the total Other Income and Deduction falls from values of \$6.2 M and \$6.4 M in 2013 and 2014 respectively to between \$5.0 M and \$5.4 M in each of the test years (2016-2020).

**RESPONSE:**

a) The 2016-2020 forecasted revenue from late payment charges is developed using an average of 3 of the prior years. For example the 2016 forecast year of \$2.038M is calculated from the average of revenue values from Y2015, Y2014 and Y2013. The chart below shows the actuals and the forecast years used for the test years assumptions. 2016 to 2020 is lower based on the 2013 year being lower which brings down the average.

| Late Payment | (\$M) | | (\$M) |
|---|---|---|---|
| Y2010 actual | 2.457 | Y2015 forecast | 2.022 |

| | | | |
|---|---|---|---|
| Y2011 actual | 2.184 | Y2016 forecast | 2.038 |
| Y2012 actual | 1.973 | Y2017 forecast | 2.077 |
| Y2013 actual | 1.923 | Y2018 forecast | 2.046 |
| Y2014 actual | 2.183 | Y2019 forecast | 2.054 |
| Y2014 forecast at budget time | 2.169 | Y2020 forecast | 2.059 |

b) Both 2013 and 2014 had a number of one-time refunds received which were extraordinary and are not expected to continue into 2016 to 2020. These included a surplus in health and benefits received in 2013 for $300,000 and in 2014 for $600,000; this is not expected to continue as the service provider has been changed. There was also a one-time insurance claim received in 2014 for $767,000 as a result of an assessment conducted in relation to the loss of assets.

## EXHIBIT J: OPERATION, MAINTENANCE AND ADMINISTRATION EXPENSES

**J-AMPCO-29**

**REF: Ex. J-Tab 2**

a) Page 1: Please provide the assumptions in this application for the annual inflation adjustment under the PWU Collective Agreement for the years 2016 to 2020.

b) Page 2, Appendix 2-K: Please reproduce the table to breakout executive from management, overtime and incentive pay from salary and wages, and temporary staff from permanent. Please add rows to indicate the percentage capitalized and expensed.

c) Please discuss PowerStream's contracting out strategy.

**RESPONSE:**

a) To be filed in confidence.

b) See table below.

| | 2012 Actual | 2013 Board Approved | 2013 Actual | 2014 Actual | 2015 Forecast | 2016 Forecast | 2017 Forecast | 2018 Forecast | 2019 Forecast | 2020 Forecast |
|---|---|---|---|---|---|---|---|---|---|---|
| **Number of Employees (FTEs including Part-Time)** | | | | | | | | | | |
| Executive | 26.30 | 27.20 | 27.12 | 27.18 | 30.00 | 30.00 | 30.00 | 30.00 | 30.00 | 30.00 |
| Management | 77.26 | 83.00 | 77.29 | 78.18 | 82.50 | 87.50 | 87.00 | 87.75 | 88.75 | 88.75 |
| Non-Union | 51.58 | 63.00 | 57.28 | 58.54 | 66.50 | 69.00 | 73.75 | 74.00 | 74.00 | 74.00 |
| Union | 319.86 | 340.60 | 318.29 | 318.97 | 337.60 | 338.85 | 343.60 | 343.60 | 344.60 | 342.60 |
| Temp & students | 43.94 | 36.85 | 53.12 | 61.22 | 50.85 | 41.52 | 27.52 | 27.52 | 27.52 | 27.52 |
| **Total** | **518.94** | **550.65** | **533.10** | **544.09** | **567.45** | **566.87** | **561.87** | **562.87** | **564.87** | **562.87** |
| **Total Salary and Wages** | | | | | | | | | | |
| Executive | $ 4,656,389 | $ 4,921,180 | $ 4,832,959 | $ 5,003,884 | $ 5,681,614 | $ 5,821,783 | $ 5,953,345 | $ 6,079,079 | $ 6,157,878 | $ 6,300,564 |
| Management | $ 8,346,567 | $ 9,059,063 | $ 8,495,118 | $ 8,887,037 | $ 9,382,204 | $ 10,155,300 | $ 10,365,731 | $ 10,693,012 | $ 11,079,896 | $ 11,356,359 |
| Non-Union | $ 4,631,020 | $ 5,693,054 | $ 5,264,787 | $ 5,480,726 | $ 6,253,505 | $ 6,636,447 | $ 7,235,377 | $ 7,486,315 | $ 7,692,789 | $ 7,873,102 |
| Union | $ 23,456,646 | $ 25,164,828 | $ 24,090,422 | $ 24,866,942 | $ 25,887,535 | $ 26,870,309 | $ 28,114,569 | $ 28,895,671 | $ 29,670,610 | $ 30,227,137 |
| Temp & students | $ 1,873,242 | $ 1,404,595 | $ 2,592,480 | $ 3,137,598 | $ 2,216,509 | $ 1,649,894 | $ 985,162 | $ 987,389 | $ 989,802 | $ 992,267 |
| **Total** | **$ 42,963,863** | **$ 46,242,720** | **$ 45,275,766** | **$ 47,376,187** | **$ 49,421,367** | **$ 51,133,732** | **$ 52,654,185** | **$ 54,141,466** | **$ 55,590,975** | **$ 56,749,428** |
| **Over Time** | | | | | | | | | | |
| Executive | $ - | $ - | $ - | $ - | | | | | | |
| Management | $ 107,139 | $ - | $ 124,142 | $ 274,886 | $ 85,000 | $ 85,000 | $ 85,000 | $ 85,000 | $ 85,000 | $ 85,000 |
| Non-Union | $ 7,653 | | $ 4,415 | $ 27,512 | | | | | | |
| Union | $ 3,373,889 | $ 2,870,725 | $ 3,193,871 | $ 4,121,769 | $ 2,511,718 | $ 2,619,847 | $ 2,649,972 | $ 2,700,969 | $ 2,757,366 | $ 2,811,170 |
| Temp & students | $ 12,878 | $ - | $ 4,140 | $ 32,542 | $ - | $ - | $ - | $ - | $ - | $ - |
| **Total** | **$ 3,501,559** | **$ 2,870,725** | **$ 3,326,569** | **$ 4,456,709** | **$ 2,596,718** | **$ 2,704,847** | **$ 2,734,972** | **$ 2,785,969** | **$ 2,842,366** | **$ 2,896,170** |
| **Performance Incentive Plan** | | | | | | | | | | |
| Executive | $ 1,354,712 | $ 1,136,987 | $ 1,401,655 | $ 1,475,540 | $ 1,536,189 | $ 1,572,177 | $ 1,606,371 | $ 1,639,698 | $ 1,662,676 | $ 1,701,069 |
| Management | $ 556,202 | $ 591,353 | $ 719,689 | $ 749,437 | $ 824,993 | $ 894,758 | $ 916,108 | $ 943,802 | $ 976,011 | $ 1,000,082 |
| Non-Union | $ 292,453 | $ 319,375 | $ 407,570 | $ 392,494 | $ 479,040 | $ 505,252 | $ 548,497 | $ 566,894 | $ 582,108 | $ 595,568 |
| Union | $ - | $ - | $ 17,874 | $ 24,420 | $ 28,073 | $ - | $ - | $ - | $ - | $ - |
| Temp & students | $ 20,000 | $ - | $ 2,739 | $ 4,703 | $ - | $ - | $ - | $ - | $ - | $ - |
| **Total** | **$ 2,223,368** | **$ 2,047,714** | **$ 2,549,527** | **$ 2,646,594** | **$ 2,868,295** | **$ 2,972,187** | **$ 3,070,976** | **$ 3,150,394** | **$ 3,220,795** | **$ 3,296,719** |
| **Total Benefits (Current + Accrued)** | | | | | | | | | | |
| Executive | $ 1,179,348 | $ 679,708 | $ 1,333,121 | $ 1,443,540 | $ 990,158 | $ 1,006,395 | $ 1,021,705 | $ 1,044,099 | $ 1,064,861 | $ 1,089,169 |
| Management | $ 2,782,581 | $ 3,110,933 | $ 2,989,214 | $ 3,092,574 | $ 3,495,213 | $ 3,721,372 | $ 3,776,012 | $ 3,871,903 | $ 3,994,920 | $ 4,093,684 |
| Non-Union | $ 1,216,323 | $ 1,574,323 | $ 1,481,929 | $ 1,460,207 | $ 2,194,849 | $ 2,314,709 | $ 2,511,693 | $ 2,575,444 | $ 2,626,656 | $ 2,686,617 |
| Union | $ 7,434,769 | $ 9,885,736 | $ 7,793,367 | $ 7,871,822 | $ 8,315,182 | $ 8,598,099 | $ 8,930,792 | $ 9,110,153 | $ 9,315,229 | $ 9,504,412 |
| Temp & students | $ 243,113 | $ 241,434 | $ 328,851 | $ 407,221 | $ 448,866 | $ 405,248 | $ 343,882 | $ 350,826 | $ 357,815 | $ 364,977 |
| **Total** | **$ 12,856,134** | **$ 15,492,134** | **$ 13,926,483** | **$ 14,275,363** | **$ 15,444,267** | **$ 16,045,824** | **$ 16,584,084** | **$ 16,952,425** | **$ 17,359,481** | **$ 17,738,859** |
| **Total Compensation including Benefits** | | | | | | | | | | |
| Executive | $ 7,190,449 | $ 6,737,874 | $ 7,567,735 | $ 7,922,964 | $ 8,207,961 | $ 8,400,355 | $ 8,581,422 | $ 8,762,876 | $ 8,885,415 | $ 9,090,802 |
| Management | $ 11,792,488 | $ 12,761,349 | $ 12,328,163 | $ 13,003,934 | $ 13,787,410 | $ 14,856,430 | $ 15,142,851 | $ 15,593,717 | $ 16,135,827 | $ 16,535,125 |
| Non-Union | $ 6,147,450 | $ 7,586,752 | $ 7,158,701 | $ 7,360,939 | $ 8,927,395 | $ 9,456,408 | $ 10,295,566 | $ 10,628,652 | $ 10,901,554 | $ 11,155,287 |
| Union | $ 34,265,303 | $ 37,921,288 | $ 35,095,535 | $ 36,884,953 | $ 36,742,508 | $ 38,088,254 | $ 39,695,333 | $ 40,706,794 | $ 41,743,205 | $ 42,542,718 |
| Temp & students | $ 2,149,233 | $ 1,646,029 | $ 2,928,210 | $ 3,582,065 | $ 2,665,374 | $ 2,055,142 | $ 1,329,044 | $ 1,338,215 | $ 1,347,617 | $ 1,357,244 |
| **Total** | **$ 61,544,923** | **$ 66,653,293** | **$ 65,078,344** | **$ 68,754,854** | **$ 70,330,648** | **$ 72,856,589** | **$ 75,044,216** | **$ 77,030,255** | **$ 79,013,616** | **$ 80,681,176** |
| | | | | | | | | | | |
| **Total Compensation Charged to OM&A** | **$ 40,789,066** | **$ 44,141,066** | **$ 42,914,690** | **$ 43,313,155** | **$ 48,034,792** | **$ 49,894,415** | **$ 51,003,819** | **$ 52,237,951** | **$ 53,416,983** | **$ 54,460,566** |
| **Total Compensation Capitalized** | **$ 20,755,857** | **$ 22,512,227** | **$ 22,163,654** | **$ 25,441,699** | **$ 22,295,856** | **$ 22,962,174** | **$ 24,040,397** | **$ 24,792,304** | **$ 25,596,633** | **$ 26,220,610** |
| **% in OMA** | **66%** | **66%** | **66%** | **63%** | **68%** | **68%** | **68%** | **68%** | **68%** | **68%** |
| **% in Capital** | **34%** | **34%** | **34%** | **37%** | **32%** | **32%** | **32%** | **32%** | **32%** | **32%** |

c) PowerStream has a balanced resource strategy that uses a mix of internal and external resources to accomplish the approved capital and maintenance programs and projects. We have relationships with key contractor resources which are market tested through RFP processes.

**J-CCC-53**

Please provide a copy of any policies or guidelines regarding PowerStream's employee expenses. Please include the policies applicable to all categories of employees, including executives.

**RESPONSE:**

Included are the policies regarding PowerStream's employee expenses.

- Employee Business Expenses Policy (J-CCC-53-Appendix A)
- Mileage Allowance (J-CCC-53-Appendix B)

**J-CCC-54**

**REF: Ex. J/T2/p. 2**

Please describe the payment structure for PowerStream's senior executives. Please include incentive policies (Performance Incentive Program) and any applicable scorecards.

**RESPONSE:**

PowerStream's Senior Executives are paid a base salary, incentive pay and benefits.

**J-CCC-55**

**REF: Ex. J/T2/p. 1**

What percentage of PowerStream's employees are unionized? Will that percentage change during the rate plan? If so, in what way?

**RESPONSE:**

The percentage of PowerStream union employees will remain consistent of approximately 60% throughout the rate plan.

**J-CCC-56**

Please provide a copy of PowerStream's policy regarding overtime. Please identify actual and forecast overtime costs for each year 2012-2020.

**RESPONSE:**

**<u>Over Time Policy:</u>**

Please see the attached appendixes:

- Appendix J-CCC-56 A for union overtime policy
- Appendix J-CCC-56 B for management and non-union overtime policy. Although the review date has passed for this policy it still is in effect.

**<u>Over Time Costs</u>**

| 2012 Actual | 2013 Board Approved | 2013 Actual | 2014 Actual | 2015 Forecast | 2016 Forecast | 2017 Forecast | 2018 Forecast | 2019 Forecast | 2020 Forecast |
|---|---|---|---|---|---|---|---|---|---|
| $3,501,559 | $2,870,725 | $3,326,569 | $4,456,709 | $2,596,718 | $2,704,847 | $2,734,972 | $2,785,969 | $2,842,366 | $2,896,170 |

**J-CCC-57**

**REF: Ex. J, Appendix 2-JA**

PowerStream is significantly ramping up its capital expenditures regarding System Renewal. Please explain the relationship of these costs to the level of operating costs embedded in the revenue requirement. Will this capital spending reduce the overall O&M costs? If not, why not? If so, please identify where the reductions to O&M are captured. Specifically, please explain why Maintenance costs are increasing over the term of the plan.

**RESPONSE:**

Please refer to Consolidated Distribution System Plan, Section 5.3.3 Asset Lifecycle Optimization Policies and Procedures, Pages 28 to 34.

**J-CCC-58**

Please explain, in detail, the relationship between PowerStream and Collingwood PowerStream Services Corporation. What benefits does that relationship have for PowerStream customers? If operating costs have been reduced because of the arrangements in place, please identify where those reductions have been made. Does PowerStream intend to enter into any similar arrangements during the term of the rate plan? Would this involve a re-opening of the plan?

**RESPONSE:**

PowerStream owns 50% interest of Collingwood PowerStream Utility Services Corporation, whose subsidiaries includes Collus PowerStream Corporation, Collus PowerStream Solutions Corporation and Collus PowerStream Energy Corporation.

As indicated in Appendix 2-N, PowerStream provides Collus PowerStream some limited support services, through shared service agreements, in areas such as Rates & Regulatory, Corporate Services, Finance, Operations, etc., on an as needed basis. PowerStream bills Collus PowerStream for the fully allocated costs plus a small mark-up. The mark-up and the recovery of a small portion of fixed costs provide a benefit to PowerStream customers.

The small amount of revenue realized from these services is a revenue offset and reduces the revenue requirement to be collected from PowerStream's customers.

PowerStream does not have any specific plans to enter into more of this type of arrangement. The addition or loss of an arrangement of this nature with its relatively small dollar amount would not justify a re-opening of the plan.

**J-CCC-59**

Does PowerStream intend to move to monthly billing? Has PowerStream undertaken any analysis to assess the costs and benefits of moving to monthly billing? If so, please provide that analysis.

**RESPONSE:**

Yes. PowerStream intends to move to monthly billing as directed by the Board. PowerStream is implementing a new billing system in 2015. The timing of monthly billing will be largely dependent on the stabilization of the new billing system.

Please refer to G-Energy Probe-17 for costs and benefits assessment of moving to monthly billing.

**J-CCC-60**

How many of PowerStream's customers subscribe to e-billing? What is the estimated annual take up of e-billing? Have the cost savings associated with increased e-billing been incorporated into the OM&A forecasts? Please identify the projected savings expected in each year of the rate plan.

**RESPONSE:**

There were 31,159 customers that have subscribed to e-billing as at December 31, 2014.

Currently it is estimated that approximately 31,194 customers or 8.5% of total customers will be on e-billing for 2015. PowerStream estimates a further 1% increase in customers being added to e-billing per year. By 2020 it is expected that there will be 13.5% of customers on e-billing.

Projected savings of $144,000 has been built into the 2015 budget and each year from 2016-2020 the projected savings built in are $20,000 per year based on the assumption of participation in the e-billing program as a result of reduction of costs for postage, paper, invoice and envelopes.

**J-CCC-61**

**REF: Ex. J/T1/p. 3**

Vegetation Management costs are increasing significantly from $300 million in 2015 to more than $600 million in 2016 and more than $500 million in the other years throughout the plan period. Please provide the business case analysis to justify these increased expenditures. Is this work carried out by permanent staff or by contractors?

**RESPONSE:**

The December 2013 Ice Storm caused widespread outages on the PowerStream distribution system, with power lines being severely impacted by falling trees and limbs. Much damage was sustained in areas with a significant concentration of rear-lot distribution, and these areas required significant amounts of resources and the longest periods of time to repair distribution plant and restore power. As a result of the Ice Storm, external reviews were conducted around system hardening, and vegetation management was an OM&A focus in order to help prevent outages like the 2013 Ice Storm from occurring again. Therefore, vegetation management costs increased $300,000 in 2015 from 2014 and another $600,000 in 2016 over 2015 and continue to increase at $500,000 per year from 2017 to 2020. These increases are the result of PowerStream implementing system hardening measures which include increasing the tree clearance cutback around lines, complete removal of any limbs overhanging lines (referred to as “blue-skying”), removal of hazard trees located close to a power line where failures of the tree could pose a hazard to the line, and implementing vegetation management around secondary wires on customer properties.

These changes are supported by a study that was conducted by CIMA (an independent third party) and is attached in J-CCC-61 Appendix A. This study was conducted as a result of the 2013 ice storm and supports effectively “hardening” the distribution system against ice storms and severe weather in general. Specifically related to vegetation management, CIMA recommended the following:

- enhancing the trim zone
- incorporating aspects of reliability centered maintenance in the fixed pruning cycle program

- instituting a "Hazard Tree" program that identifies trees outside the trim zone that are tall enough to contact the overhead distribution system and are also dead, declining, diseased, or otherwise structurally unsound
- including proactive service line clearing on private property as part of the three year trim cycle; continuing to educate and inform the municipalities, property developers and clients on vegetation near power lines and how they can help to keep the network safe
- training design staff and construction in basic vegetation management to help identify potential problems

The work that is expected to be performed will be carried out by contractors.

**J-CCC-62**

**REF: Ex. J, Appendix 2-JA**

Please provide detailed budgets for the following OM&A categories in the same format as Appendix 2-JA: Billing and Collecting; Community Relations; and Administrative and General. Please describe the major components of these budget areas – what specific functions are included. Please explain why spending in each of these areas is increasing over the term of the plan.

**RESPONSE:**

<u>Billing and Collecting</u>

| **Finance** | **Bridge Year** | **Test Years** | | | | |
|---|---|---|---|---|---|---|
| **In $000** | **2015 Budget** | **2016 Budget** | **2017 Budget** | **2018 Budget** | **2019 Budget** | **2020 Budget** |
| **Customer Service** | **$16,711** | **$17,282** | **$16,745** | **$16,881** | **$17,176** | **$17,473** |
| $ Increase | | $571 | ($537) | $137 | $295 | $297 |
| % Increase | | 3.4% | -3.1% | 0.8% | 1.7% | 1.7% |

Customer Service handles meter to cash activities for approximately 356,000 customers in the PowerStream service area. Customer Service performs billing, customer relations and customer credit activities.

*2016 Budget over 2015 Budget, $571,000 or 3.4%*

The year over year increases are moderate at approximately 3.4% for Billing and Collection. In 2016, the CIS stabilization phase begins to wind down in support of the new CIS. The need for temporary staff is lessened in order to provide backfill for daily operations. OM&A labour costs begin to return to relatively normal levels with labour escalation impacts only resulting in an overall increase of $406,000 which includes reductions in CIS stabilization contract costs of approximately $250,000.

*2017 Budget over 2016 Budget, ($537,000) or -3.1%*

The year over year variance is attributable to the removal of 14 temporary staff that assisted with the implementation and stabilization phases of the new CIS. Temporary staff provided operational support in order to facilitate the dedication of subject matter experts to the stabilization effort. Total Labour costs are lower by approximately $451,000.

*2018 to 2020 Budget*

The year over year variances are moderate during this period and are mainly attributable to labour cost escalation and increase in general expenses due to inflationary pressures which were offset by the incremental reductions in the outsourced call centre costs. In 2019 and 2020 outsourced call centre is no longer required and costs return to their normal levels.

Community Relations

| Corporate Services | Bridge Year | Test Years | | | | |
|---|---|---|---|---|---|---|
| In $000 | 2015 Budget | 2016 Budget | 2017 Budget | 2018 Budget | 2019 Budget | 2020 Budget |
| **Corporate Communications** | **$1,806** | **$2,124** | **$2,194** | **$2,221** | **$2,250** | **$2,276** |
| $ Increase | | $318 | $70 | $27 | $28 | $26 |
| % Increase | | 17.6% | 3.3% | 1.3% | 1.3% | 1.2% |

The Corporate Communications function is the business unit responsible for community relations. They are responsible for leading and executing all internal and external communications and related processes for PowerStream. Responsibilities include development, implementation and monitoring of corporate communications strategies and tactics, as well as customer communications, media and general public relations, employee communications, branding, crisis communication, and corporate social responsibility activities.

*2016 budget over 2015 bridge, $318,000 or 17.6%*

The year over year increase is due to a change in Sponsorship classifications in 2016, resulting in all Sponsorships (see table below) being included in the corporate communications business unit. In prior years, only a small portion of Sponsorships (Character, Fairs/Festivals, Earth Hour) were partially recovered through rates, however, this methodology was revisited and hence revised to include all Sponsorships.

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| **Sponsorships** | **2016 Budget** |
|---|---|
| Character | $12,500 |
| Fairs/Festivals | $37,000 |
| Earth Hour | $3,000 |
| Hospital Galas | $37,500 |
| Business Awards | $28,500 |
| Parades | $8,500 |
| Misc Corporate | $47,000 |
| Vaughan misc | $22,500 |
| Vaughan Mayor | $41,500 |
| Markham misc | $11,000 |
| Markham Mayor | $19,050 |
| Barrie Misc | $15,000 |
| Barrie Mayor | $9,000 |
| Shareholder unallocated | $25,450 |
| ***Total Sponsorships*** | ***$317,500*** |

*2020 budget over 2016 budget, $152,000 or 7.2%*

The 2016 through 2020 budget years are expected to see an average OM&A increase of 1.8% per annum driven by labour and other general inflationary cost increases.

Administrative and General

The administration and general category includes four business units being corporate services, corporate finance and reporting, rates and regulatory and corporate. The details of these business units are set out below.

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Corporate Services

| Corporate Services | Bridge Year | Test Years | | | | |
|---|---|---|---|---|---|---|
| In $000 | 2015 Budget | 2016 Budget | 2017 Budget | 2018 Budget | 2019 Budget | 2020 Budget |
| **Supply Chain Services** | **$5,979** | **$6,277** | **$6,351** | **$6,424** | **$6,493** | **$6,559** |
| $ Increase | | $298 | $73 | $73 | $69 | $65 |
| % Increase | | 5.0% | 1.2% | 1.2% | 1.1% | 1.0% |
| **Information Services** | **$9,132** | **$9,085** | **$9,260** | **$9,256** | **$9,454** | **$9,484** |
| $ Increase | | ($48) | $175 | ($3) | $197 | $30 |
| % Increase | | -0.5% | 1.9% | -0.04% | 2.1% | 0.3% |
| **Legal** | **$513** | **$639** | **$737** | **$761** | **$787** | **$808** |
| $ Increase | | $126 | $99 | $24 | $26 | $21 |
| % Increase | | 24.6% | 15.4% | 3.2% | 3.4% | 2.7% |
| **HR & Organizational Effectiveness** | **$5,458** | **$5,669** | **$5,736** | **$5,776** | **$5,883** | **$5,982** |
| $ Increase | | $210 | $67 | $40 | $106 | $100 |
| % Increase | | 3.9% | 1.2% | 0.7% | 1.8% | 1.7% |

Supply Chain Services oversees the management of Strategic Sourcing and Facilities, Inventory Management and Fleet.

*2016 budget over 2015 bridge, $298,000 or 5.0%*

The year over year increase in Facilities costs are due to the fact, that previous to 2015, a portion of the office space at PowerStream's Jane street office was utilized by the CIS project team and capitalized in the cost of the CIS project. After quarter two 2015, the project was complete and the office space was reabsorbed into the facilities business unit. In 2016 the full year impact of the reabsorption of office space occurred which increased OM&A.

*2020 budget over 2016 budget, $282,000 or 4.5%*

The 2016 through 2020 budget years are expected to see a steady OM&A increase of 1.1% per annum driven by labour and other general inflationary cost increases.

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Information Services provides Operations and Support; Strategic Planning and Administration; Enterprise Resource Planning (ERP) Services; Customer Information System (CIS) Services; and Information Security support service activities to the organization.

*2020 budget over 2015 bridge, $352,000 or 3.9%*

The 2015 through 2020 budget years are expected to see a steady OM&A increase of 0.8% per annum driven by labour and other general inflationary cost increases, except for the increase in 2017 resulting from the addition of the new Security Analyst position, combined with the full year impact of the Sr. Technical Specialist & Database Administrator roles.

Legal is principally responsible for: providing legal advice to staff at all levels on a broad spectrum of matters; reviewing, drafting, and/or negotiating various contracts; and providing counsel on various risk mitigation issues.

2016 budget over 2015 bridge, $126,000 or 24.6%

The 2016 Legal budget is higher than 2015 due to the inclusion of one incremental headcount for a new Contracts Manager position.

2017 budget over 2016 budget, $99,000 or 15.4%

The 2017 Legal budget is higher than 2016 due to the annualized impact of the new Contracts Manager position hired in 2016, in addition to labour and other general inflationary cost increases.

2020 budget over 2017 budget, $71,000 or 9.6%

The 2017 through 2020 budget years are expected to see an average OM&A increase of 3.2% per annum driven by labour and other general inflationary cost increases.

The HR & Organizational Effectiveness function provides strategic and management partner services to each business unit within PowerStream. The function is, comprised of four teams, specializing in: Human Resources Services; Health & Safety Services; Organizational Effectiveness; Enterprise Risk and Internal Audit.

2016 budget over 2015 bridge, $210,000 or 3.9%

The overall year over year variance in 2016 is due to growth in the Health and Safety and Enterprise Risk & Internal Audit headcount. The new headcount includes the addition of a Health and Safety Trainer role and a new Co-op student role in Enterprise Risk & Internal Audit.

2020 budget over 2016 budget, $313,000 or 5.5%

The 2016 through 2020 budget years are expected to see an average OM&A increase of 1.4% per annum driven by labour and other general inflationary cost increases.

<u>Corporate Finance and Reporting</u>

| **Finance** | **Bridge Year** | **Test Years** | | | | |
|---|---|---|---|---|---|---|
| **In $000** | **2015 Budget** | **2016 Budget** | **2017 Budget** | **2018 Budget** | **2019 Budget** | **2020 Budget** |
| **Corporate Finance & Reporting** | **$5,701** | **$6,049** | **$6,183** | **$6,308** | **$6,534** | **$6,589** |
| $ Increase | | $347 | $134 | $125 | $226 | $55 |
| % Increase | | 6.1% | 2.2% | 2.0% | 3.6% | 0.8% |

Corporate Finance, Accounting, and Reporting team perform two key business support and operational functions being: General Accounting; and Corporate Finance. The General Accounting team provide support to the organization by performing Corporate Accounting and Payroll activities. The Corporate Finance team provides decision making support through financial reporting and analysis; strategic planning, financial modeling, and treasury functions.

*2016 Budget over 2015 Budget, $347,000 or 6.1%*

The year over year variance is mainly attributable to increases in consulting funds. These costs have increased to fund productivity improvements related to the automation and improvement of some key finance functions. The remainder of the increase is mainly attributable to labour cost escalation and increases in general expenses due to inflationary pressures.

*2016 Budget to 2018 Budget, $259,000 or 2.1% average per annum*

The year over year variances are moderate during this period and are mainly attributable to labour cost escalation and increases in general expenses due to inflationary pressures.

*2019 Budget over 2018 Budget, $226,000 or 3.6%*

In addition to labour cost escalation and inflation, there were increases in general expenses due to the increased cost of $81,000 for an additional pre-hire resource to be trained as a Payroll Supervisor in preparation of a retirement in 2020.

*2020 Budget over 2019 Budget, $55,000 or 0.8%*

The year over year variances are moderate during this period and are mainly attributable to labour cost escalation and increase in general expenses due to inflationary pressures.

<u>Rates and Regulatory</u>

| Finance | Bridge Year | Test Years | | | | |
|---|---|---|---|---|---|---|
| In $000 | 2015 Budget | 2016 Budget | 2017 Budget | 2018 Budget | 2019 Budget | 2020 Budget |
| **Rates & Regulatory Affairs** | **$3,259** | **$3,034** | **$3,061** | **$3,115** | **$3,080** | **$3,134** |
| $ Increase | | ($226) | $27 | $54 | ($35) | $54 |
| % Increase | | -6.9% | 0.9% | 1.8% | -1.1% | 1.8% |

Rates and Regulatory Affairs assists in the development of regulatory strategy, budgeting, analyzing load forecasts and accounting for distribution revenue. In addition, this team is responsible for overseeing the preparation, filing and regulatory process for defending rate applications, performing and monitoring regulatory accounting, and engaging in government relations.

*2016 Budget over 2015 Bridge Year, ($226,000) or - 6.9%*

In 2015 PowerSteam's legal, consulting and OEB intervenor costs increased as result of the submission of the 2016 to 2020 custom IR rate application. In 2016 OM&A costs are lower due to the reduction in legal, consulting and OEB Intervenor costs as a result of the completion of the 2016 - 2020 Custom IR application.

*2020 Budget over 2016 Budget, $100,000 or 0.8%*

The year over year variances are moderate during this period and are mainly attributable to labour cost escalation and increase in general expenses due to inflationary pressures

<u>Corporate</u>

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| Corporate | Bridge Year | Test Years | | | | |
|---|---|---|---|---|---|---|
| In $000 | 2015 Budget | 2016 Budget | 2017 Budget | 2018 Budget | 2019 Budget | 2020 Budget |
| **Corporate** | **$8,591** | **$8,660** | **$8,919** | **$9,025** | **$9,202** | **$9,380** |
| $ Increase | | $69 | $259 | $106 | $177 | $178 |
| % Increase | | 0.8% | 3.0% | 1.2% | 2.0% | 1.9% |

The Corporate business unit incorporates the costs associated with the strategic leadership of the Executive Management Team (EMT). Administration costs of Board meetings, including the support of the Audit and Finance Committees, applicable Executive professional development and necessary business travel are supported through this work program.

*2016 Budget over 2015 Bridge, $69,000) or 0.8%*

The primary reason for this increase is due to the addition of a new headcount in 2016 for Strategic Support. This position is included for half a year in 2016. The remaining year over year variances are moderate during this period and are mainly attributable to labour cost escalation and increase in general expenses due to inflationary pressures offset by the 2015 Website project.

2017 Budget over 2016 Budget, $259,000 or 3.0%

The primary reason for this increase is due to the headcount increase in 2016 for Strategic Support that was included at half year and is now in the forecast for a full year. The remaining year over year variances are moderate during this period and are mainly attributable to labour cost escalation and increase in general expenses due to inflationary pressures.

2017 Budget to 2020 Budget, $461,000 or 1.7% average per annum

For the Budget period 2017 – 2020, cost increases are within 2.0% per year, consistent with inflation and are mainly attributable to labour cost escalation and increase in general expenses due to inflationary pressures.

**J-Energy Probe-33**

**REF: Ex. J, Tab 1, Table 1**

a) What do Notes 1 and 2 refer to below Table 1?

b) Is the 1.6% shown for 2016 through 2020 the inflation rate used for non-compensation related expenses? If not, what inflation rate has PowerStream used for non-compensation related OM&A expenses?

**RESPONSE:**

a) Note 1 in Exhibit J, Tab 1, Table 1 notes that the change from the opening balance in the 2013 Actual of $82,941,000 compared to the total incremental change from 2013 actual to 2015 bridge year of $89,188,000 only represents a 2% change per year over those three years.

Note 2 in Exhibit J, Tab 1, Table 1 notes that the change from the opening balance in the 2016 test year of $92,558,000 compared to the total incremental change from 2016 test year to 2020 test year of $104,904,000 only represents a 1.6% change per year over those five years.

b) The inflation rate used for planning purposes for non-compensation related OM&A is 1%. The 1.6% as explained in the response to part (a) above is a composite of the increase in all OM&A costs..

**J-Energy Probe-34**

**REF: Ex. J, Tab 1, Table 1**

a) The evidence states that there was a $1,809,000 OM&A increase due to the 2013 ice storm. Please confirm that this amount is included in the $1,872,000 figure shown in Table 1.

b) What was the change in vegetation management costs in 2012 from the previous year?

c) Where are the cost reductions associated with no longer maintaining the previous CIS system shown in Table 1?

**RESPONSE:**

a. Yes, the $1,809,000 increase due to the ice storm is included in the $1,872,000 figure shown in Table 1 of Exhibit J tab 1.

b. The change in the vegetation costs from 2011 to 2012 is $42,629.

c. The legacy CIS will be maintained to the end of 2017 to enable PowerStream to effectively manage processes which fall outside of the new CC&B's standard capabilities, as a result, PowerStream is unable to realize maintenance savings during this period.

**J-Energy Probe-35**

**REF: Ex. J, Tab 1, Table 1**

Please add a line to Table 1 that shows for each year shown, the OM&A expense associated with joint services expenses that correspond to the $2,941,000 shown for 2013 Board Approved.

**RESPONSE:**

A line titled “joint services expenses” has been added in the cost driver table below that shows OM&A expenses related to the joint services.

| Total OM&A ($000's) | 2013 Actual | 2014 Actual | 2015 Bridge Year | 2016 Test Year | 2017 Test Year | 2018 Test Year | 2019 Test Year | 2020 Test Year | 2013 Actuals to 2015 Bridge Year | 2016 to 2020 Test Years |
|---|---|---|---|---|---|---|---|---|---|---|
| **Opening Balance** | **82,941** | **80,849** | **85,454** | **92,558** | **96,216** | **98,112** | **99,920** | **102,195** | **82,941** | **92,558** |
| | | | | | | | | | | |
| Compensation | (204) | 538 | 2,508 | 1,136 | 267 | 745 | 787 | 901 | 2,842 | 3,837 |
| Asset Management | (922) | 1,949 | 579 | 472 | 578 | 364 | 416 | 369 | 1,605 | 2,199 |
| Risk Management | (109) | 330 | 757 | 518 | 485 | (36) | 138 | (103) | 978 | 1,002 |
| Growth | (73) | 59 | 144 | 369 | 140 | 232 | 87 | 106 | 131 | 935 |
| Customer Expectation | 95 | 754 | (248) | 58 | 25 | 25 | 25 | 25 | 602 | 158 |
| Compliance | (361) | 262 | 185 | 132 | 18 | 18 | 18 | 19 | 86 | 205 |
| Other | (2,305) | 1,058 | 1,343 | 396 | (73) | 19 | 172 | 43 | 96 | 557 |
| Joint Services Expenses | (84) | (128) | 121 | 85 | 88 | 91 | 93 | 96 | (92) | 454 |
| | | | | | | | | | | |
| **Closing Balance-Business as usual** | **78,977** | **85,670** | **90,844** | **95,724** | **97,745** | **99,571** | **101,657** | **103,650** | **89,188** | **101,904** |
| **Year over year ($)** | | **6,693** | **5,173** | **4,881** | **2,021** | **1,826** | **2,086** | **1,993** | | |
| **Year over year (%)** | | **8.5%** | **6.0%** | **5.4%** | **2.1%** | **1.9%** | **2.1%** | **2.0%** | | |
| **<u>Extra-ordinary items</u>** | | | | | | | | | | |
| Vegetation Management | 1,872 | (1,565) | 403 | 614 | 526 | 531 | 536 | 542 | 710 | 2,749 |
| CIS Implementation | - | 1,349 | 1,310 | (122) | (158) | (182) | 1 | 1 | 2,659 | (460) |
| **Closing Balance-Business with Extra-ordinary items** | **80,849** | **85,454** | **92,558** | **96,216** | **98,112** | **99,920** | **102,195** | **104,193** | **92,558** | **104,193** |
| **Year over year ($)** | | **4,605** | **7,104** | **3,659** | **1,896** | **1,808** | **2,275** | **1,999** | | |
| **Year over year (%)** | | **5.7%** | **8.3%** | **4.0%** | **2.0%** | **1.8%** | **2.3%** | **2.0%** | | |

**J-Energy Probe-36**

**REF: Ex. J, Tab 2, Appendix 2-K**

Please provide a version of Appendix 2-K that adds lines to the bottom of the table that shows the amount of total compensation that was expensed as OM&A and the amount of total compensation that was capitalized for each of the years shown.

**RESPONSE:**

**Appendix 2-K Showing OMA and Capital Split**

| | 2012 Actual | 2013 Board Approved | 2013 Actual | 2014 Actual | 2015 Forecast | 2016 Forecast | 2017 Forecast | 2018 Forecast | 2019 Forecast | 2020 Forecast |
|---|---|---|---|---|---|---|---|---|---|---|
| **Number of Employees (FTEs including Part-Time)[1]** | | | | | | | | | | |
| Management (including executive) | 103.56 | 110.20 | 104.41 | 105.36 | 112.50 | 117.50 | 117.00 | 117.75 | 118.75 | 118.75 |
| Non-Management (union and non-union) | 415.38 | 440.45 | 428.69 | 438.73 | 454.95 | 449.37 | 444.87 | 445.12 | 446.12 | 444.12 |
| Total | **518.94** | **550.65** | **533.10** | **544.09** | **567.45** | **566.87** | **561.87** | **562.87** | **564.87** | **562.87** |
| **Total Salary and Wages including ovetime and incentive pay** | | | | | | | | | | |
| Management (including executive) | $ 15,021,009 | $ 15,708,582 | $ 15,573,563 | $ 16,390,784 | $ 17,510,000 | $ 18,529,018 | $ 18,926,555 | $ 19,440,591 | $ 19,961,461 | $ 20,443,074 |
| Non-Management (union and non-union) | $ 33,667,780 | $ 35,452,576 | $ 35,578,299 | $ 38,088,707 | $ 37,376,380 | $ 38,281,748 | $ 39,533,577 | $ 40,637,238 | $ 41,692,675 | $ 42,499,243 |
| Total | **$ 48,688,789** | **$ 51,161,159** | **$ 51,151,862** | **$ 54,479,491** | **$ 54,886,381** | **$ 56,810,766** | **$ 58,460,132** | **$ 60,077,830** | **$ 61,654,136** | **$ 62,942,317** |
| **Total Benefits (Current + Accrued)** | | | | | | | | | | |
| Management (including executive) | $ 3,961,929 | $ 3,790,641 | $ 4,322,335 | $ 4,536,113 | $ 4,485,371 | $ 4,727,768 | $ 4,797,718 | $ 4,916,002 | $ 5,059,781 | $ 5,182,854 |
| Non-Management (union and non-union) | $ 8,894,205 | $ 11,701,493 | $ 9,604,147 | $ 9,739,250 | $ 10,958,897 | $ 11,318,056 | $ 11,786,367 | $ 12,036,423 | $ 12,299,700 | $ 12,556,006 |
| Total | **$ 12,856,134** | **$ 15,492,134** | **$ 13,926,483** | **$ 14,275,363** | **$ 15,444,267** | **$ 16,045,824** | **$ 16,584,084** | **$ 16,952,425** | **$ 17,359,481** | **$ 17,738,859** |
| **Total Compensation (Salary, Wages, & Benefits)** | | | | | | | | | | |
| Management (including executive) | $ 18,982,938 | $ 19,499,223 | $ 19,895,898 | $ 20,926,897 | $ 21,995,371 | $ 23,256,785 | $ 23,724,272 | $ 24,356,593 | $ 25,021,241 | $ 25,625,928 |
| Non-Management (union and non-union) | $ 42,561,986 | $ 47,154,069 | $ 45,182,446 | $ 47,827,957 | $ 48,335,277 | $ 49,599,804 | $ 51,319,944 | $ 52,673,662 | $ 53,992,375 | $ 55,055,249 |
| Total | **$ 61,544,923** | **$ 66,653,293** | **$ 65,078,344** | **$ 68,754,854** | **$ 70,330,648** | **$ 72,856,589** | **$ 75,044,216** | **$ 77,030,255** | **$ 79,013,616** | **$ 80,681,176** |
| **Total Compensation Charged to OM&A** | **$ 40,789,066** | **$ 44,141,066** | **$ 42,914,690** | **$ 43,313,155** | **$ 48,034,792** | **$ 49,894,415** | **$ 51,003,819** | **$ 52,237,951** | **$ 53,416,983** | **$ 54,460,566** |
| **Total Compensation Capitalized** | **$ 20,755,858** | **$ 22,512,227** | **$ 22,163,654** | **$ 25,441,699** | **$ 22,295,856** | **$ 22,962,174** | **$ 24,040,397** | **$ 24,792,304** | **$ 25,596,633** | **$ 26,220,610** |

**J-Energy Probe-37**

**REF: Ex. J, Tab 2**

a) The annual inflation adjustment for unionized employees is shown as 2.5% in 2013 and 2.75% in each of 2014 and 2015. What was the annual increase in 2013, 2014 and 2015 for non-union and management employees?

b) What increase has PowerStream forecast for each of 2016 through 2020 for each of the unionized and non-union and management employee categories?

**RESPONSE:**

PowerStream's Senior Executives are paid a base salary, incentive pay and benefits and forms part of the employment contract. The CEO's incentive plan is based on 80% corporate goals and 20% individual goals, and the Executive Vice Presidents is based on 70% corporate goals and 30% individual goals.

**J-Energy Probe-38**

**REF: Ex. J, Tab 4, Appendix J-4-1**

The evidence states that PowerStream is not requesting any adjustment to the Custom IR plan test years for costs associated with this application, which are included in the amounts shown in Appendix J-4-1 in the amounts for 2014 and 2015.

a) One time regulatory costs shown for each of 2016 through 2020 range from $555,000 to $566,000, which is more than double the amount shown for 2013. These amounts include consultant costs, legal costs, intervenor costs and applicant originated applications. Please explain what these on-going one-time costs are associated with.

b) PowerStream is forecasting a 5% increase in OEB annual assessment costs in 2015, followed by 1% increases in each of the following years, despite reductions recorded in 2013 and 2014. What is the basis for this forecast increase in the bridge and test years?

**RESPONSE:**

a) Please see the response to J-VECC-31 for restatement of Appendix 2-M. Table J-EP-38-1 below summarizes the revised one-time and ongoing regulatory costs. One-time costs relate to legal, consulting, intervenors and Board assessed costs related to applications and other regulatory consultations.

**Table J-EP-38-1: Regulatory Cost Summary**

| | On-Time | Ongoing | Total Costs |
|---|---|---|---|
| **2013 BA** | $ 320,000 | $ 2,068,002 | $ 2,388,002 |
| **2012** | $ 557,543 | $ 1,990,182 | $ 2,547,725 |
| **2013** | $ 107,147 | $ 1,873,187 | $ 1,980,334 |
| **2014** | $ 503,287 | $ 2,001,056 | $ 2,504,343 |
| **2015 Bridge** | $ 658,079 | $ 1,985,412 | $ 2,643,491 |
| **2016 Test** | $ 402,236 | $ 2,011,677 | $ 2,413,913 |
| **2017 Test** | $ 405,658 | $ 2,030,153 | $ 2,435,811 |
| **2018 Test** | $ 409,114 | $ 2,061,687 | $ 2,470,802 |
| **2019 Test** | $ 412,606 | $ 2,049,355 | $ 2,461,961 |
| **2020 Test** | $ 416,132 | $ 2,080,955 | $ 2,497,087 |

b) The OEB Annual Cost Assessment, the 2015 Bridge year was calculated based on a 3 year average comprising of actuals from 2011, 2012 and 2013 plus a 1% increase for inflation. The 2016-2020 Test years were increases of 1% per annum due to inflation.

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**J-Energy Probe-39**

**REF: Ex. J, Tab 3**

a) Over what period is the CIS system being depreciated?

b) Please provide a schedule that shows the addition to rate base of the CIS system and the calculation of the depreciation expense from the time the capital expenditures were closed to rate base through 2020.

c) Please indicate where in Appendix G-2a-1 the CIS addition to rate base and the calculation of the depreciation, accumulated depreciation and net book value is shown.

**RESPONSE:**

a) The new CIS software is being amortized over 10 years.
b) Table J-EP-39-1 below shows the addition of the new CIS to rate base.

**Table J-EP-39-1: CIS System Addition to Rate Base and Depreciation Expense**

| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|
| Opening NFA | $ - | $ 40.7 | $ 36.4 | $ 32.1 | $ 27.8 | $ 23.5 |
| Addition | $ 42.8 | | | | | |
| Depreciation | -$ 2.1 | -$ 4.3 | -$ 4.3 | -$ 4.3 | -$ 4.3 | -$ 4.3 |
| Closing NFA | $ 40.7 | $ 36.4 | $ 32.1 | $ 27.8 | $ 23.5 | $ 19.3 |
| **Rate Base amount** | **$ 20.3** | **$ 38.5** | **$ 34.2** | **$ 30.0** | **$ 25.7** | **$ 21.4** |

c) The CIS additions and other software expenditures are included in the line for account 1611, “Computer Software”.

**J-Energy Probe-40**

**REF: Ex. J, Tab 3**

a) Please calculate the depreciation expense for each of 2012 through 2014 if the half year rule had been used instead of the monthly in-service methodology.

b) What methodology was used to calculate depreciation in the last cost of service application (EB-2012-0161)?

**RESPONSE:**

a) See Table J-EP-40-1 below for a comparison of depreciation for 2012 to 2014 calculated on the half year rule versus monthly in-service method.

**TABLE J-EP-40-1: Depreciation Summary - Monthly In-service vs. Half-Year Method ($000s)**

| | 2012 Monthly | 2012 Half-year | 2012 Variance | 2013 Monthly | 2013 Half Year | 2013 Variance | 2014 Monthly | 2014 Half Year | 2014 Variance |
|---|---|---|---|---|---|---|---|---|---|
| Distribution Assets | $32,351 | $32,601 | ($249) | $34,038 | $34,487 | ($449) | $36,725 | $36,920 | ($195) |
| General Plant Assets | $8,427 | $8,670 | ($243) | $8,974 | $9,670 | ($696) | $9,972 | $10,069 | ($96) |
| Other Capital Assets | $733 | $733 | $0 | $731 | $731 | $0 | $731 | $731 | ($0) |
| Sub- Total | $41,511 | $42,003 | ($492) | $43,743 | $44,888 | ($1,145) | $47,428 | $47,719 | ($291) |
| Contributed Capital Amortization | ($8,199) | ($8,206) | $7 | ($8,873) | ($8,933) | $60 | ($9,413) | ($9,492) | $79 |
| Depreciation | $33,313 | $33,797 | ($485) | $34,870 | $35,955 | ($1,085) | $38,015 | $38,227 | ($212) |
| Less: RGCRP | ($50) | ($50) | $0 | ($73) | ($73) | $0 | ($105) | ($105) | $0 |
| Allocated to OM&A | ($1,766) | ($1,881) | $115 | ($1,954) | ($2,098) | $144 | ($2,107) | ($2,205) | $98 |
| Total Depreciation | $31,497 | $31,867 | ($370) | $32,843 | $33,783 | ($940) | $35,803 | $35,918 | ($115) |

Note: RGCRP - Renewable generation connection rate protection represents depreciation expense reimbursed, Ontario Reg. 330/09

b) In PowerStream's 2013 Cost of Service application (EB-2012-0161), depreciation for the actual additions was calculated on the monthly in-service method and depreciation on the forecast additions was calculated on the half-year rule. This issue went to hearing and the Board ruled that the use of the half-year rule for forecast periods was consistent with Board policy.

**J-Energy Probe-41**

**REF: Ex. J, Tab 5**

PowerStream proposes to adjust the taxes recoverable amount annually to reflect changes in legislated tax rates. Does this adjustment apply only to changes in the tax rates, or does it also apply to changes in CCA rates and any changes/additions in tax credits?

**RESPONSE:**

PowerStream proposes to recalculate the taxes recoverable amount by updating the OEB tax model for:

- Updated regulatory net income
- Tax rate changes

PowerStream is agreeable to updating CCA rates in the model.

PowerStream is agreeable to rescaling of the apprentice and co-op tax credits based on changes in the tax credit amounts. For example if the per person rate increases or decreases by 10% then the credit would be increased or decreased by 10%.

PowerStream is agreeable to adjusting the tax credits for any new tax credits that are legislated, clearly available to PowerStream and the amount can be readily determined.

PowerStream is uncertain how it would update the SR&ED tax credit in the scope of an annual update due to the complexity and the timing of when information is available.

**J-Energy Probe-42**

**REF: Ex. J, Tab 5, Appendix J-5-1**

a) On Sheet P Schedule 10 Test Year, the cost of eligible capital property acquired during 2016 is shown as $34,000, but only $34 to $36 in subsequent test years. Should these figures be $34,000 to $36,000?

b) Please reconcile the amounts shown on line 4 of Sheet S Taxable Income Test Year with the figures shown in Table 1 in Exhibit J, Tab 3.

c) Please explain why there does not appear to be any loss carry forward from 2015 into 2016 despite a regulatory taxable income loss in 2015 of $8.7 million.

d) Sheet S Taxable Income Test Year shows $61,000 for each year as a gain on disposal of assets (line 401). Please show where this gain is shown in the Other Revenues.

e) How has PowerStream calculated the scientific research expenses claimed in each of 2016 through 2020 as shown on line 411 on Sheet S Taxable Income Test Year?

**RESPONSE:**

a) Yes this is a clerical error. The additions for to eligible capital property for 2017 to 2020 should be in the range of $34,000 to $36,000.

b) Table J-EP-42-1 below reconciles the addition in calculating taxable income for amortization of tangible assets to the depreciation expense shown in Table 1 in Exhibit J, Tab 3.

**Table J-EP-42-1: Reconciliation of Depreciation Expense to Addition for Tax**

| ($ thousands) | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|
| Total Depreciation | $ 45,713 | $ 49,648 | $ 52,333 | $ 55,190 | $ 58,328 |
| less funded by RGCRP | -$ 110 | -$ 108 | -$ 106 | -$ 105 | -$ 105 |
| Add derecognition expense | $ 1,300 | $ 1,300 | $ 1,300 | $ 1,300 | $ 1,300 |
| **Total Addition for tax** | **$ 46,903** | **$ 50,840** | **$ 53,527** | **$ 56,386** | **$ 59,524** |
| Allocated to OM&A | $ 2,406 | $ 2,512 | $ 2,637 | $ 2,864 | $ 2,888 |
| **Revised total addition for tax** | **$ 49,309** | **$ 53,352** | **$ 56,164** | **$ 59,250** | **$ 62,412** |

Note 1. Depreciation expense per Exhibit J, Tab 3, Table 1.

PowerStream has added the amounts shown on the “Total Addition for tax” line in Table J-EP-42-1. In answering this interrogatory, PowerStream discovered that an error was made. The amount of depreciation and amortization re-allocated to OM&A should also be added back in determining taxable income. The correct amount to be added is shown in Table J-EP-42-1 as “Revised total addition for tax”. It is proposed that this be corrected in an update later in this process.

c) PowerStream intends to utilize the taxable losses arising in 2015 in that year.

d) The estimate of $61,000 as a gain on disposal was based on an average of the actual amounts from the 2013 and 2014 taxes, without reference to the Other Revenue forecast.  There are no gains on disposition of assets forecast in other revenues.

e) PowerStream has taken an average of the actual SR&ED amounts for the three years 2011 to 2013.

**J-Energy Probe-43**

**REF: Ex. J, Tab 5, Appendix J-5-1 & Appendix G-2a-1**

a) Please reconcile the additions to rate base shown in Appendix G-2a-1 for each of 2015 through 2020 with the CCA and CEC additions shown in Appendix J-5-1.

b) Please explain why the additions to CCA Class 12 are lower in every year as compared to the additions shown in the fixed asset continuity schedules for account 1611.

**RESPONSE:**

a) Table J-EP-43-1 below reconciles the in-service capital additions per Appendix G-2a-1 with the CCA and CEC additions in the tax model for 2015 to 2020 inclusive.

**Table J-EP-43-1: Reconciliation of Rate Base Capital Additions to Tax Model ($000)**

| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|
| **G-2a Additions:** | $139,859 | $117,323 | $144,358 | $123,416 | $134,164 | $126,677 |
| less capitalized interest[1] | ($1,554) | ($1,296) | ($1,283) | ($1,224) | ($1,224) | ($1,224) |
| less RGCRP funded | ($76) | ($67) | $0 | $0 | $0 | $0 |
| **Additions for tax** | **$138,229** | **$115,960** | **$143,075** | **$122,192** | **$132,940** | **$125,453** |
| **Tax model:** | | | | | | |
| Sch. 8 CCA additions | $136,169 | $113,095 | $142,976 | $122,148 | $132,148 | $125,407 |
| Sch. 10 CEC additions | $33 | $34 | $34 | $35 | $35 | $36 |
| Land - no CCA or CEC | $1,125 | $2,889 | | $9 | $757 | $10 |
| **Tax model total** | **$137,327** | **$116,018** | **$143,010** | **$122,192** | **$132,940** | **$125,453** |
| **Variance** | **$902** | **($58)** | **$65** | **($0)** | **$0** | **($0)** |

1. Capitalized interest is deducted for tax purposes in arriving at taxable income.

Additions per Appendix G-2a-1 have been adjusted to remove capitalized interest and additions funded by the Renewable Generation Connection Rate Protection plan ("RGCRP").

There are some variances for 2015, 2016 and 2017 due to clerical errors in the amounts entered for RGCRP. PowerStream will correct this in an update to be provided after the Technical Conference and before the Settlement Conference.

b) Table J-EP-43-2 reconciles the in-service additions shown in the fixed asset continuity schedules for account 1611 to the additions to class 12. The difference is the capitalized interest that is expensed for tax purposes.

**Table J-EP-43-2: Reconciliation of Account 1611 to Class 12 Additions ($000)**

| **G-2a Additions:** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
|---|---|---|---|---|---|---|
| Account 1611 | $47,637 | $9,413 | $10,466 | $6,320 | $7,880 | $8,212 |
| less capitalized interest | ($579) | ($113) | ($98) | ($66) | ($76) | ($84) |
| **Additions for tax** | **$47,058** | **$9,300** | **$10,368** | **$6,254** | **$7,804** | **$8,128** |
| Class 12 additions | $47,058 | $9,300 | $10,368 | $6,254 | $7,804 | $8,128 |
| **Variance** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** |

**J-Energy Probe-44**

**REF: Ex. J, Tab 5**

a) Please provide the number of positions eligible for each of the apprenticeship training tax credit, the co-op education tax credit and the federal job creation tax credit for each of 2012 through 2020.

b) For each of the bridge and test years, please show how the number of eligible positions are used to calculate the tax credits used in the PILs calculations.

**RESPONSE:**

a) Table J-EP-44-1 below shows historical data for 2012 to 2014 for these tax credits.

**Table J-EP-44-1: Co-operative Education and Apprentice Tax Credits 2012 to 2014 Actual**

| **Tax credits (TC) Summary** | **2012** | **2013** | **2014** |
|---|---|---|---|
| Ontario Co-operative TC | $ 191,760 | $ 187,159 | $ 173,171 |
| Ontario Apprentice Training TC | $ 177,298 | $ 221,038 | $ 186,877 |
| Federal Job Creation TC | $ 38,767 | $ 31,113 | $ 28,318 |
| **Total** | **$ 407,825** | **$ 439,310** | **$ 388,366** |
| **Ontario Co-operative TC** | **2012** | **2013** | **2014** |
| Number of work periods | 77 | 79 | 66 |
| Total amount | $ 191,760 | $ 187,159 | $ 173,171 |
| Average per work period | $ 2,490 | $ 2,369 | $ 2,624 |
| **Ontario Apprentice Training TC** | **2012** | **2013** | **2014** |
| Number of apprentices | 20 | 29 | 21 |
| Total amount | $ 177,298 | $ - | $ 186,877 |
| Average per apprentice | $ 8,865 | $ - | $ 8,899 |

| **Federal Job Creation TC** | **2012** | **2013** | **2014** |
|---|---|---|---|
| Number of apprentices | 20 | 18 | 15 |
| Total amount | $ 38,767 | $ 31,113 | $ 28,318 |
| Average per apprentice | $ 1,938 | $ 1,729 | $ 1,888 |

Note: 2014 amounts are from the tax return currently in preparation and not yet filed.

The amounts for 2015 to 2020, summarized in Table J-EP-44-2 below, were estimated in total based on the 2014 preliminary estimated total of $496,000 for these tax credits. As can be seen in Table J-EP-44-1 above, the actual amounts to be filed for 2014 are much lower.

**Table J-EP-44-2: Co-operative Education and Apprentice Tax Credits Forecast**

| **Tax credits (TC)** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
|---|---|---|---|---|---|---|
| **Total** | **$ 505,900** | **$ 516,000** | **$ 526,400** | **$ 536,900** | **$ 547,600** | **$ 558,600** |

b) The calculation of each of these credits is much more complex than a flat amount times the number of qualifying individuals.

See part (a) above for an explanation of how the tax credit amounts used in the tax model were forecast.

**J-SEC-31**

**REF: Ex. J-1, p.3**

Please provide all internal or external analysis done regarding the changing of the tree trimming cycle.

**RESPONSE:**

***5-year Cycle to 3-year Cycle***

Prior to 2012, in the PowerStream South service territory, vegetation management was undertaken on a 5-year cycle. However, this cycle proved less than effective, as in reality labour and financial resources were primarily focused on reactive activities such as addressing trouble spots and worst performing feeders. In the North service territory, a 3-year cycle was in place and most activity was focused on maintaining the proactive 3-year cycle compared to reactive-type work.

In 2012, PowerStream reviewed its vegetation management program and concluded that the objectives of safety, customer service, and reliability would be better served with a consistent and proactive program across all service territories. The need for increased emphasis on proactive activity to maintain adequate clearances and reduce the probability of trees contacting power lines was further driven by increased storm activity, since the probability of tree contacts during storms is heightened. Practices of other LDCs were also surveyed. It was decided to establish a 3-year cycle across all PowerStream service territories, thereby implementing a more optimal cycle and harmonising the practices across all predecessor utilities. This also facilitated better program management, as it was more effective to manage a consistent cycle across all territories rather than maintaining different practices in various areas. These conclusions are summarised in the document "*PowerStream Annual Distribution Inspection and Maintenance Programs, June 2012*", see J-SEC-31 Appendix A.

***3-year cycle to 2-year rear lots, 3 year cycle to 4-year rural***

The December 2013 Ice Storm caused widespread outages on the PowerStream distribution system, with power lines being severely impacted by falling trees and limbs. Much damage was sustained in areas with a significant concentration of rear-lot distribution, and these areas required significant amounts of resources and the longest periods of time to repair distribution plant and restore power. In the aftermath of the storm, an internal review was conducted of PowerStream's response to the storm and level of preparedness for similar events in the future. The study gave rise to a number of Action Items, one of them being to make changes to the tree-trimming program cycle.

In 2013 and 2014, PowerStream's Vegetation Management cycle was 3-years across its service territory. Vegetation in each area is addressed once every 3-years, regardless of the concentration of customers or density of foliage in the area. A review of the existing Vegetation Management Program was conducted, and it was decided to reduce rear-lot cycle from 3-years to 2-years, extend rural area cycles from 3-year to 4-year, and to maintain urban area cycles at 3-years. Details of the cycle change in 2015 can be found in the document "Vegetation Management Program Review Phase 1: 2013 Ice Storm Action Items," see J-SEC-31 Appendix B.

For external analysis, PowerStream compared tree trimming cycles to other LDC's (best industry practices).

**J-SEC-32**

**REF: Ex. J-2**

Please provide a copy of the Applicant's 2014 and 2015 corporate scorecard or similar document.

**RESPONSE:**

Corporate Scorecards for 2014 and 2015 are included as J-SEC-32 Appendix A.

**J-SEC-33**

**REF: Ex. J-2, p.1**

For the purposes of the 2016-2020 plan, what assumptions are PowerStream making regarding the outcome of its next collective agreement with the PWU?

**RESPONSE:**

There are no additional assumptions regarding the outcome of the next Collective Agreement in the 2016 to 2020 plan, except the annual inflation adjustments.

**J-SEC-34**

**REF: Ex. J-2, Appendix 2-K**

Please add two rows to show total compensation capitalized, and charged to OM&A.

**RESPONSE:**

**Appendix 2-K with OMA and Capital Split**

| | 2012 Actual | 2013 Board Approved | 2013 Actual | 2014 Actual | 2015 Forecast | 2016 Forecast | 2017 Forecast | 2018 Forecast | 2019 Forecast | 2020 Forecast |
|---|---|---|---|---|---|---|---|---|---|---|
| **Number of Employees (FTEs including Part-Time)[1]** | | | | | | | | | | |
| Management (including executive) | 103.56 | 110.20 | 104.41 | 105.36 | 112.50 | 117.50 | 117.00 | 117.75 | 118.75 | 118.75 |
| Non-Management (union and non-union) | 415.38 | 440.45 | 428.69 | 438.73 | 454.95 | 449.37 | 444.87 | 445.12 | 446.12 | 444.12 |
| Total | **518.94** | **550.65** | **533.10** | **544.09** | **567.45** | **566.87** | **561.87** | **562.87** | **564.87** | **562.87** |
| **Total Salary and Wages including ovetime and incentive pay** | | | | | | | | | | |
| Management (including executive) | $ 15,021,009 | $ 15,708,582 | $ 15,573,563 | $ 16,390,784 | $ 17,510,000 | $ 18,529,018 | $ 18,926,555 | $ 19,440,591 | $ 19,961,461 | $ 20,443,074 |
| Non-Management (union and non-union) | $ 33,667,780 | $ 35,452,576 | $ 35,578,299 | $ 38,088,707 | $ 37,376,380 | $ 38,281,748 | $ 39,533,577 | $ 40,637,238 | $ 41,692,675 | $ 42,499,243 |
| Total | **$ 48,688,789** | **$ 51,161,159** | **$ 51,151,862** | **$ 54,479,491** | **$ 54,886,381** | **$ 56,810,766** | **$ 58,460,132** | **$ 60,077,830** | **$ 61,654,136** | **$ 62,942,317** |
| **Total Benefits (Current + Accrued)** | | | | | | | | | | |
| Management (including executive) | $ 3,961,929 | $ 3,790,641 | $ 4,322,335 | $ 4,536,113 | $ 4,485,371 | $ 4,727,768 | $ 4,797,718 | $ 4,916,002 | $ 5,059,781 | $ 5,182,854 |
| Non-Management (union and non-union) | $ 8,894,205 | $ 11,701,493 | $ 9,604,147 | $ 9,739,250 | $ 10,958,897 | $ 11,318,056 | $ 11,786,367 | $ 12,036,423 | $ 12,299,700 | $ 12,556,006 |
| Total | **$ 12,856,134** | **$ 15,492,134** | **$ 13,926,483** | **$ 14,275,363** | **$ 15,444,267** | **$ 16,045,824** | **$ 16,584,084** | **$ 16,952,425** | **$ 17,359,481** | **$ 17,738,859** |
| **Total Compensation (Salary, Wages, & Benefits)** | | | | | | | | | | |
| Management (including executive) | $ 18,982,938 | $ 19,499,223 | $ 19,895,898 | $ 20,926,897 | $ 21,995,371 | $ 23,256,785 | $ 23,724,272 | $ 24,356,593 | $ 25,021,241 | $ 25,625,928 |
| Non-Management (union and non-union) | $ 42,561,986 | $ 47,154,069 | $ 45,182,446 | $ 47,827,957 | $ 48,335,277 | $ 49,599,804 | $ 51,319,944 | $ 52,673,662 | $ 53,992,375 | $ 55,055,249 |
| Total | **$ 61,544,923** | **$ 66,653,293** | **$ 65,078,344** | **$ 68,754,854** | **$ 70,330,648** | **$ 72,856,589** | **$ 75,044,216** | **$ 77,030,255** | **$ 79,013,616** | **$ 80,681,176** |
| **Total Compensation Charged to OM&A** | **$ 40,789,066** | **$ 44,141,066** | **$ 42,914,690** | **$ 43,313,155** | **$ 48,034,792** | **$ 49,894,415** | **$ 51,003,819** | **$ 52,237,951** | **$ 53,416,983** | **$ 54,460,566** |
| **Total Compensation Capitalized** | **$ 20,755,858** | **$ 22,512,227** | **$ 22,163,654** | **$ 25,441,699** | **$ 22,295,856** | **$ 22,962,174** | **$ 24,040,397** | **$ 24,792,304** | **$ 25,596,633** | **$ 26,220,610** |

**J-SEC-35**

**REF: Ex. J-2, Appendix 2-K**

Please provide a version of Appendix 2-K, on a per employee (FTE) basis.

**RESPONSE:**

The Per Employee (FTE) data is added to the bottom of the chart in blue colour:

| | 2012 Actual | 2013 Board Approved | 2013 Actual | 2014 Actual | 2015 Forecast | 2016 Forecast | 2017 Forecast | 2018 Forecast | 2019 Forecast | 2020 Forecast |
|---|---|---|---|---|---|---|---|---|---|---|
| **Number of Employees (FTEs including Part-Time)[1]** | | | | | | | | | | |
| Management (including executive) | 103.56 | 110.20 | 104.41 | 105.36 | 112.50 | 117.50 | 117.00 | 117.75 | 118.75 | 118.75 |
| Non-Management (union and non-union) | 415.38 | 440.45 | 428.69 | 438.73 | 454.95 | 449.37 | 444.87 | 445.12 | 446.12 | 444.12 |
| Total | **518.94** | **550.65** | **533.10** | **544.09** | **567.45** | **566.87** | **561.87** | **562.87** | **564.87** | **562.87** |
| **Total Salary and Wages including ovetime and incentive pay** | | | | | | | | | | |
| Management (including executive) | $ 15,021,009 | $ 15,708,582 | $ 15,573,563 | $ 16,390,784 | $ 17,510,000 | $ 18,529,018 | $ 18,926,555 | $ 19,440,591 | $ 19,961,461 | $ 20,443,074 |
| Non-Management (union and non-union) | $ 33,667,780 | $ 35,452,576 | $ 35,578,299 | $ 38,088,707 | $ 37,376,380 | $ 38,281,748 | $ 39,533,577 | $ 40,637,238 | $ 41,692,675 | $ 42,499,243 |
| Total | **$ 48,688,789** | **$ 51,161,159** | **$ 51,151,862** | **$ 54,479,491** | **$ 54,886,381** | **$ 56,810,766** | **$ 58,460,132** | **$ 60,077,830** | **$ 61,654,136** | **$ 62,942,317** |
| **Total Benefits (Current + Accrued)** | | | | | | | | | | |
| Management (including executive) | $ 3,961,929 | $ 3,790,641 | $ 4,322,335 | $ 4,536,113 | $ 4,485,371 | $ 4,727,768 | $ 4,797,718 | $ 4,916,002 | $ 5,059,781 | $ 5,182,854 |
| Non-Management (union and non-union) | $ 8,894,205 | $ 11,701,493 | $ 9,604,147 | $ 9,739,250 | $ 10,958,897 | $ 11,318,056 | $ 11,786,367 | $ 12,036,423 | $ 12,299,700 | $ 12,556,006 |
| Total | **$ 12,856,134** | **$ 15,492,134** | **$ 13,926,483** | **$ 14,275,363** | **$ 15,444,267** | **$ 16,045,824** | **$ 16,584,084** | **$ 16,952,425** | **$ 17,359,481** | **$ 17,738,859** |
| **Total Compensation (Salary, Wages, & Benefits)** | | | | | | | | | | |
| Management (including executive) | $ 18,982,938 | $ 19,499,223 | $ 19,895,898 | $ 20,926,897 | $ 21,995,371 | $ 23,256,785 | $ 23,724,272 | $ 24,356,593 | $ 25,021,241 | $ 25,625,928 |
| Non-Management (union and non-union) | $ 42,561,986 | $ 47,154,069 | $ 45,182,446 | $ 47,827,957 | $ 48,335,277 | $ 49,599,804 | $ 51,319,944 | $ 52,673,662 | $ 53,992,375 | $ 55,055,249 |
| Total | **$ 61,544,923** | **$ 66,653,293** | **$ 65,078,344** | **$ 68,754,854** | **$ 70,330,648** | **$ 72,856,589** | **$ 75,044,216** | **$ 77,030,255** | **$ 79,013,616** | **$ 80,681,176** |
| **Salary and Wages (including ovetime and incentive pay) per FTE** | | | | | | | | | | |
| Management (including executive) | $ 145,040 | $ 142,546 | $ 149,161 | $ 155,570 | $ 155,644 | $ 157,694 | $ 161,765 | $ 165,101 | $ 168,097 | $ 172,152 |
| Non-Management (union and non-union) | $ 81,054 | $ 80,492 | $ 82,993 | $ 86,816 | $ 82,155 | $ 85,190 | $ 88,865 | $ 91,295 | $ 93,456 | $ 95,693 |
| All | **$ 93,823** | **$ 92,910** | **$ 95,952** | **$ 100,130** | **$ 96,725** | **$ 100,218** | **$ 104,046** | **$ 106,735** | **$ 109,147** | **$ 111,824** |
| **Benefits (Current + Accrued) per FTE** | | | | | | | | | | |
| Management (including executive) | $ 38,256 | $ 34,398 | $ 41,399 | $ 43,054 | $ 39,870 | $ 40,236 | $ 41,006 | $ 41,749 | $ 42,609 | $ 43,645 |
| Non-Management (union and non-union) | $ 21,412 | $ 26,567 | $ 22,404 | $ 22,199 | $ 24,088 | $ 25,186 | $ 26,494 | $ 27,041 | $ 27,570 | $ 28,272 |
| All | **$ 24,774** | **$ 28,134** | **$ 26,124** | **$ 26,237** | **$ 27,217** | **$ 28,306** | **$ 29,516** | **$ 30,118** | **$ 30,732** | **$ 31,515** |
| **Total Compensation (Salary, Wages, & Benefits) per FTE** | | | | | | | | | | |
| Management (including executive) | $ 183,295 | $ 176,944 | $ 190,560 | $ 198,624 | $ 195,514 | $ 197,930 | $ 202,772 | $ 206,850 | $ 210,705 | $ 215,797 |
| Non-Management (union and non-union) | $ 102,466 | $ 107,059 | $ 105,397 | $ 109,015 | $ 106,243 | $ 110,376 | $ 115,359 | $ 118,336 | $ 121,027 | $ 123,965 |
| All | **$ 118,597** | **$ 121,045** | **$ 122,076** | **$ 126,367** | **$ 123,942** | **$ 128,524** | **$ 133,562** | **$ 136,853** | **$ 139,879** | **$ 143,339** |

**J-SEC-36**

**Appendix 2-M**

Please explain the budgeting of significant consulting cost for regulatory matters between 2016-2020.

**RESPONSE:**

The increase in consulting costs from 2016-2020 are as a result of contract support that relates to the support in the following areas:

- Annual rate filing updates
- Cost allocation studies
- Support for Settlement services and other regulation changes
- Support for changes to OEB filing guidance, OEB billing and other initiatives
- Support for outreach to political parties, provincial advocacy and provide help on lobbying energy policy
- Support enhanced customer engagement

**J-SEC-38**

**Appendix 2-JC**

For all material year over year variance, please provide an explanation.

**RESPONSE:**

A Materiality threshold of $770,000 has been applied per the OEB Filing Requirements in chapter 2 which states:

*"The applicant must provide justification for changes from year to year to its rate base, capital expenditures, OM&A and other items above a materiality threshold. The materiality thresholds differ for each applicant, depending on the magnitude of the revenue requirement.*

*0.5% of distribution revenue requirement for a distributor with a distribution revenue requirement greater than $10 million and less than or equal to $200 million"*

Therefore, 0.5% of $154 million is $770,000 and will be applied as a threshold for material year over year variances discussed below. This is based on PowerStream's 2013 Board Approved base Revenue Requirement of $154 million.

**ASSET MANAGEMENT**

**LINES**

| | | | | **Bridge Year** | **Test Years** | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **In $000** | **2013 OEB Approved** | **2013 Actual** | **2014 Actual** | **2015 Budget** | **2016 Budget** | **2017 Budget** | **2018 Budget** | **2019 Budget** | **2020 Budget** |
| **Lines** | **$12,046** | **$13,919** | **$13,040** | **$14,161** | **$15,172** | **$15,898** | **$16,783** | **$17,488** | **$18,301** |
| $ Increase | | $1,873 | ($880) | $1,121 | $1,012 | $725 | $885 | $705 | $813 |

**Detailed Variance Analysis: 2013 Actual vs. Board Approved**

2013 Actual over Board Approved, $1,873,036

The variance to Board Approved costs is mainly attributable to higher than anticipated reactive maintenance work that was completed to address storm damage and cable faults. Storm damage for 2013 is approximately $1,809,264 over Board Approved amounts.

**Detailed Variance Analysis: 2014 Actual vs. 2013 Actual**

2014 Actual over 2013 Actual, ($879,662)

The year over year variance is mainly attributable to lower storm damage costs in 2014 as compared to 2013. This is offset by repairs for cable faults which increased in 2014 due to the fact that PowerStream's territory experienced an extremely wet year, which caused an increase in secondary faults. The cost increase for this reactive maintenance effort is approximately $646,572 over 2013 actuals.

**Detailed Variance Analysis: 2015 Bridge Year vs. 2014 Actual**

2015 Bridge Year over 2014 Actual, $1,121,182

The year over year variance is mainly attributable to increases in vegetation management, and operational support.

Vegetation management increased in 2015 by approximately $300,334, this increase is the result of focussing on rear lot and heavily forested areas for tree trimming; an outcome of the 2013 Ice Storm.

Operational support, training and other have increased approximately $404,365 from 2014. This is attributable to labour escalations and increases in general expenses due to inflationary pressures. A further increase of $160,000 is attributable to higher training costs and a temporary increase in labour costs due to pre-hires that are needed to transition employees to key management roles as a result of retirements.

**Detailed Variance Analysis: 2016 Budget to 2020 Budget**

2016 Budget over 2015 Bridge year, $1,012,000

The year over year variance is mainly attributable to an increase in the vegetation management program by approximately $521,000 or 25%. Part of the increase relates to PowerStream's efforts on system hardening which is the result of PowerStream's focus on outage management and the ability to reduce outage times and restoration efforts that result from damage in heavily forested areas. In addition there was a few other contributors to the increase in the 2016 budget as noted below:

- new supervisor - this position was added to oversee and manage the increased cycle trimming.
- pre-hire of management staff to train for upcoming retirements,
- the hire of a project coordinator who will provide greater emphasis on project scheduling and resource planning. This project coordinator will also create improved work scheduling and resource allocation leading to efficiency gains.
- There is also a hire of a Lines Supervisor to manage increased capital and maintenance workload and to provide greater emphasis on scheduling and resource planning.

The 2017 budget to 2020 budget period includes increases as a result of system hardening and has moderate year over year increases for other maintenance activities that are attributable to labour escalation and increases in contract costs as a result of inflationary pressures.

## FINANCE

## CUSTOMER SERVICE

| **Finance** | | | | **Bridge Year** | **Test Years** | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **In $000** | **2013 OEB Approved** | **2013 Actual** | **2014 Actual** | **2015 Budget** | **2016 Budget** | **2017 Budget** | **2018 Budget** | **2019 Budget** | **2020 Budget** |
| **Customer Service** | **$14,124** | **$13,642** | **$16,089** | **$16,711** | **$17,282** | **$16,745** | **$16,881** | **$17,176** | **$17,473** |
| $ Increase | | ($482) | $2,447 | $622 | $571 | ($537) | $137 | $295 | $297 |

**Detailed Variance Analysis: 2014 Actual vs. 2013 Actual**

2014 Actual over 2013 Actual, $2,447,177

The year over year variance is mainly attributable to cost increases in customer relations due to training costs of $1,345,000 associated with the implementation of the new CIS. In addition, PowerStream hired seven temporary staff in 2014 that were used to backfill subject matter experts needed for the CIS implementation project, this resulted in an increase in labour of $301,954. Other year over year variances included an increase in Customer Relations consulting due to a Customer Engagement Strategy costing $244,369.

**CORPORATE SERVICES**

**INFORMATION SERVICES**

| Corporate Services | | | | Bridge Year | Test Years | | | | |
|---|---|---|---|---|---|---|---|---|---|
| In $000 | 2013 OEB Approved | 2013 Actual | 2014 Actual | 2015 Budget | 2016 Budget | 2017 Budget | 2018 Budget | 2019 Budget | 2020 Budget |
| **Information Services** | **$6,904** | **$6,458** | **$6,061** | **$9,132** | **$9,085** | **$9,260** | **$9,256** | **$9,454** | **$9,484** |
| $ Increase | | ($446) | ($397) | $3,071 | ($48) | $175 | ($3) | $197 | $30 |

**Detailed Variance Analysis: 2015 Bridge Year vs 2014 Actual**

2015 Bridge Year over 2014 Actual, $3,071,000

The 2015 Information Services budget increase is driven by increased costs resulting from implementation of the new CIS system in quarter two 2015. PowerStream has negotiated a fully managed, end to end solution for application management of the CC&B Customer Information System with CGI, costing $2,000,000 annually. Labour costs are also increasing by $400,000, as a result of headcount increases for the new Senior Technical Specialist and Database Administrator roles and also due to general labour and other inflationary increases.

**J-VECC-29**

**REF: Ex. J/T-1/pg.2**

a) Please amend the cost driver table to show the cost driver related to existing 2014 FTEs (i.e. salary increases) separate from the drivers related to the post 2014 incremental FTE costs.

b) Please show the incremental (post 2014) FTEs assignment, by year, against each of the other cost driver categories shown in Table 1.

**RESPONSE:**

The cost driver table below identifies the cost drivers with existing FTE's from 2014 onwards and the cost drivers showing the incremental increases or decreases with the post 2014 FTE assignments.

**Table 1: Net Incremental New Costs for Changing Requirements and Extraordinary Items**

| Total OM&A ($000's) | 2013 Actual | 2014 Actual | 2015 Bridge Year | 2016 Test Year | 2017 Test Year | 2018 Test Year | 2019 Test Year | 2020 Test Year | 2013 Actuals to 2015 Bridge Year | 2016 to 2020 Test Years |
|---|---|---|---|---|---|---|---|---|---|---|
| **Opening Balance** | **82,941** | **80,849** | **85,454** | **92,558** | **96,216** | **98,112** | **99,920** | **102,195** | **82,941** | **92,558** |
| | | | | | | | | | | |
| a) Compensation (existing FTE's from 2014 onwards) | (204) | 538 | 2,544 | 1,046 | 161 | 723 | 800 | 874 | 2,877 | 3,605 |
| b) Compensation - Incremental FTE costs post 2014 | | | (35) | 90 | 106 | 22 | (13) | 26 | (35) | 231 |
| a) Asset Management (existing FTE's from 2014 onwards) | (922) | 1,949 | 493 | 419 | 507 | 166 | 288 | 369 | 1,520 | 1,748 |
| b) Asset Management - Incremental FTE costs post 2014 | | | 85 | 54 | 71 | 198 | 128 | - | 85 | 451 |
| a) Risk Management (existing FTE's from 2014 onwards) | (109) | 330 | 250 | 52 | 4 | (30) | 57 | 60 | 472 | 143 |
| b) Risk Management - Incremental FTE costs post 2014 | | | 507 | 466 | 481 | (6) | 81 | (163) | 507 | 859 |
| a) Growth (existing FTE's from 2014 onwards) | (73) | 59 | 144 | 331 | 140 | 232 | 87 | 106 | 131 | 897 |
| b) Growth - Incremental FTE costs post 2014 | | | - | 38 | - | - | - | - | - | 38 |
| Customer Expectation | 95 | 754 | (248) | 58 | 25 | 25 | 25 | 25 | 602 | 158 |
| Compliance | (361) | 262 | 185 | 132 | 18 | 18 | 18 | 19 | 86 | 205 |
| a) Other (existing FTE's from 2014 onwards) | (2,390) | 929 | 1,450 | 468 | 135 | 110 | 265 | 139 | (10) | 1,117 |
| b) Other - Incremental FTE costs post 2014 | | | 14 | 14 | (120) | - | - | - | 14 | (106) |
| | | | | | | | | | | |
| **Closing Balance-Business as usual** | **78,977** | **85,670** | **90,844** | **95,724** | **97,745** | **99,571** | **101,657** | **103,650** | **89,188** | **101,904** |
| **Year over year ($)** | | **6,693** | **5,173** | **4,881** | **2,021** | **1,826** | **2,086** | **1,993** | | |
| **Year over year (%)** | | **8.5%** | **6.0%** | **5.4%** | **2.1%** | **1.9%** | **2.1%** | **2.0%** | | |
| **Extra-ordinary items** | | | | | | | | | | |
| a) Vegetation Management (existing FTE's from 2014 onwards) | 1,872 | (1,565) | 403 | 521 | 526 | 531 | 536 | 542 | 710 | 2,656 |
| b) Vegetation Management - Incremental FTE costs post 2014 | | | - | 94 | - | - | - | - | - | 94 |
| CIS Implementation | - | 1,349 | 1,310 | (122) | (158) | (182) | 1 | 1 | 2,659 | (460) |
| **Closing Balance-Business with Extra-ordinary items** | **80,849** | **85,454** | **92,558** | **96,216** | **98,112** | **99,920** | **102,195** | **104,193** | **92,558** | **104,193** |
| **Year over year ($)** | | **4,605** | **7,104** | **3,659** | **1,896** | **1,808** | **2,275** | **1,999** | | |
| **Year over year (%)** | | **5.7%** | **8.3%** | **4.0%** | **2.0%** | **1.8%** | **2.3%** | **2.0%** | | |

**J-VECC-30**

**REF: Ex. J/T-2/pg.2/Appendix 2-K**

a) Please explain why the total FTEs in 2013 were 17.55 below the Board approved figure of 550.65.
b) Please provide a table showing the post 2014 incremental FTEs by job description and department.

**RESPONSE:**

a) The difference of the acutal FTE in 2013 with the Board approved figure relates to vacant positions for the various departments throughout the year.

b) Below is the post 2014 incremental FTEs by job description and department.

| | | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|
| | **Starting Level** | **560.31** | **567.45** | **566.87** | **561.87** | **562.87** | **564.87** |
| Business Development | VP Business Development | 0.80 | | | | | |
| Corporate Communications | Digital Communications Associate | 0.50 | -0.50 | 0.50 | | | |
| | Cashier/Receptionist | -2.00 | | | | | |
| | Customer Service Field Representative | -1.00 | | | | | |
| Customer Service | Customer Service Rep | 2.00 | -7.00 | -14.00 | | | |
| | Manager, Support Services | 0.50 | 0.50 | | | | |
| | Meter Reader "A" | -1.00 | | | | | |
| | Cable Locator | -1.00 | | | | | |
| | Design Technician | | 1.00 | 1.00 | | | |
| Engineering Services | Engineer in Training | 1.00 | -0.50 | 0.50 | | | |
| | Engineer, Distribution Sustainment | 0.50 | -0.50 | | | | |
| Executive Office | Manager, Strategic Support to CEO | | 0.50 | 0.50 | | | |
| | Accounting Analyst | | | -0.25 | | | |
| Finance, Accounting & Reporting | Financial Analyst | | 0.25 | | | | |
| | Supervisor, Payroll | | | | | 0.50 | -0.50 |
| | Co-op Student | 1.00 | 0.67 | | | | |
| HR & Organizational Effectiveness | Co-op Student MBA | | 1.00 | | | | |
| | Health & Safety Trainer | | 0.50 | 0.50 | | | |
| | Database Administrator | 1.00 | -0.50 | 0.50 | | | |
| Information Services | Security Analyst | | | 1.00 | -1.00 | | |
| | Senior Technical Specialist | 0.50 | -0.50 | 0.50 | | | |
| Legal | Manager, Contracts | | 0.50 | 0.50 | | | |
| | Apprentice Instructor | -1.00 | | | | | |
| | Apprentice Meter Technician | 1.00 | -1.00 | | | | |
| | Apprentice P&C Technologist | 1.00 | | | | -1.00 | |
| | Apprentice Power Lineperson | | 2.00 | 3.00 | 2.00 | 1.00 | |
| | Apprentice Station Maintenance Technician | 1.00 | 0.00 | | -1.00 | 1.00 | -1.00 |
| | Apprentice System Controller | 2.00 | 0.00 | 1.00 | -1.00 | 0.00 | -1.00 |
| | Manager, Emergency Preparedness | 1.00 | | | | | |
| | Manager, Lines Capital Works | 1.00 | -0.50 | 0.50 | | | |
| Operations and Construction | Manager, Lines Maintenance | 0.50 | 1.00 | -1.50 | | | |
| | Metering Technologist | -1.00 | | | | | |
| | Project Coordinator | | 0.50 | 0.50 | | | |
| | Protection & Control Technologist | 0.50 | | | | | |
| | Station Maintenance Technician | -1.50 | | | | | |
| | Supervisor, Lines | 0.50 | 2.00 | -0.25 | 0.50 | -0.50 | 0.50 |
| | Supervisor, Meter Records | -1.00 | | | | | |
| | Supervisor, Protection & Control | | | | 0.50 | 0.50 | |
| | Supervisor, System Control | | | | 0.50 | 0.50 | |
| | System Control Technology Support | | | 0.50 | 0.50 | | |
| Supply Chain Services | Co-op Student | 0.33 | | | | | |
| | **Net Change** | **7.14** | **-0.58** | **-5.00** | **1.00** | **2.00** | **-2.00** |
| | **Budgeted Staff Level** | **567.45** | **566.87** | **561.87** | **562.87** | **564.87** | **562.87** |

**J-VECC- 31**

**REF: Ex. J/4-1 Appendix2 M - Regulatory**

a) Please explain the derivation of the forecasts for the regulatory costs categories (1), (2) and (3).

b) Please explain why the OM&A regulatory related expenses (category No. 7) fluctuates (e.g. increases up to 2018, then decreases).

c) Please explain why regulatory costs increase during the incentive rate plan when presumably the Utility is filing fewer applications.

**RESPONSE:**

Please note that Appendix 2-M has been revised to correct the amounts extracted from the actual and forecasted OM&A amounts to provide the regulatory costs. There is no impact on the OM&A amounts included in the calculation of revenue requirement. The updated Appendix 2-M is attached.

a) Categories (1), (2) and (3) in Exhibit J, Tab 4 Appendix 2M is listed below:

| | Regulatory Cost Category | 2015 Bridge Year | 2016 TEST YEAR 1 | 2017 TEST YEAR 2 | 2018 TEST YEAR 3 | 2019 TEST YEAR 4 | 2020 TEST YEAR 5 |
|---|---|---|---|---|---|---|---|
| | (A) | | | | | | |
| 1 | OEB Annual Assessment | $ 1,014,862 | $ 1,025,011 | $ 1,035,261 | $ 1,045,614 | $ 1,056,070 | $ 1,066,631 |
| 2 | OEB Section 30 Costs (Applicant-originated) | $ 180,000 | $ - | $ - | $ - | $ - | $ - |
| 3 | OEB Section 30 Costs (OEB-initiated) | | | | | | |

For Category 1, the OEB Annual Cost Assessment, the 2015 Bridge year was calculated based on a 3 year average comprising of actuals from 2011, 2012 and 2013 plus a 1% increase for inflation. The 2016-2020 Test years were increases of 1% per annum due to inflation.

PowerStream does not record the actual costs or budget intervenor costs in this level of detail. PowerStream has budgeted Intervenor costs (Category 2, Category 3 and category) as a single amount. For comparison purposes, it is recommended that the total of these three categories be compared as shown below.

**Intervenor Costs**

| | | 2013 BA | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | OEB Section 30 Costs (Applicant-originated) | $ 110,000 | $ 157,431 | $ 25,260 | $ 33,093 | $ 180,000 | $ - | $ - | $ - | $ - | $ - |
| 3 | OEB Section 30 Costs (OEB-initiated) | | | | | | | | | | |
| 11 | Intervenor costs | $ 50,000 | $ 63,324 | $ 36,196 | $ 32,415 | $ - | $ 59,856 | $ 60,955 | $ 62,064 | $ 63,185 | $ 64,317 |
| | **Total** | **$ 160,000** | **$ 220,755** | **$ 61,456** | **$ 65,508** | **$ 180,000** | **$ 59,856** | **$ 60,955** | **$ 62,064** | **$ 63,185** | **$ 64,317** |

b) Category 7 is included in the table below:

| | Regulatory Cost Category | 2015 Bridge Year | 2016 TEST YEAR 1 | 2017 TEST YEAR 2 | 2018 TEST YEAR 3 | 2019 TEST YEAR 4 | 2020 TEST YEAR 5 |
|---|---|---|---|---|---|---|---|
| | (A) | | | | | | |
| 7 | Operating expenses associated with staff resources allocated to regulatory matters | $ 769,882 | $ 786,837 | $ 793,131 | $ 812,363 | $ 787,606 | $ 806,655 |

Category 7 includes operating expenses associated with staff resources allocated to regulatory matters. These costs are increasing up to 2018 due to inflationary increases and then decrease in 2019 due a retirement that is replaced at a lower cost.

c) The overall summary of ongoing and one-time costs are shown in the table below:

| | Regulatory Cost Category | 2015 Bridge Year | 2016 TEST YEAR 1 | 2017 TEST YEAR 2 | 2018 TEST YEAR 3 | 2019 TEST YEAR 4 | 2020 TEST YEAR 5 |
|---|---|---|---|---|---|---|---|
| | (A) | | | | | | |
| 12 | Sub-total - Ongoing Costs [3] | $ 1,985,412 | $ 2,011,677 | $ 2,030,153 | $ 2,061,687 | $ 2,049,355 | $ 2,080,955 |
| 13 | Sub-total - One-time Costs [4] | $ 658,079 | $ 402,236 | $ 405,658 | $ 409,114 | $ 412,606 | $ 416,132 |
| 14 | Total | $ 2,643,491 | $ 2,413,913 | $ 2,435,811 | $ 2,470,802 | $ 2,461,961 | $ 2,497,087 |
| | % variance Year over Year | | -8.7% | 0.9% | 1.4% | -0.4% | 1.4% |

During the rate plan, costs have increased primarily by 1% per annum due to inflationary pressures. 2019 costs have seen a reduction due to savings from a retirement and staff replacement at a lower cost.

**J-VECC-32**

**REF: Ex. J/T-1/pg. 3-5**

a) What are the incremental costs for moving the tree trimming cycle from 5 to 3 years?

**RESPONSE:**

a) The annual incremental costs for moving the tree trimming cycle from 5 to 3 years is $564,645.

# EXHIBIT K: COST OF CAPITAL

**K-Energy Probe-45**

**REF: Ex. K, Tab 1**

a) If the Board were to initiate a review of the cost of capital and make a change in the deemed capital structure for distributors for rate making purposes, would this change the deemed capital structure of PowerStream during the Custom IR period, or would any changes not be made until a subsequent rebasing under PowerStream's proposal?

b) If the Board were to initiate a review of the cost of capital and make a change in the determination of any of the cost of equity, short term debt rate or long term debt rate, would these changes be applicable during the Custom IR period under PowerStream's proposal, or would they be applicable following the end of the IR period?

**RESPONSE:**

a) PowerStream does not propose to update the deemed capital structure during the custom IR rate plan term.

b) PowerStream does propose to update the cost of capital with respect to changes in the Board’s cost of capital parameters

**K-Energy Probe-46**

**REF: Ex. K, Tab 1**

With respect to the long-term debt cost in each of the IR years, PowerStream proposes that the rate used to determine distribution rates would be subject to adjustment annually.

Does PowerStream also propose that the amount and timing of new long term debt would be subject to review as part of the annual adjustment mechanism, given the various factors, such as the timing of capital expenditures and financial market conditions that impact the timing and amount of new long term debt? If not, please explain why not.

**RESPONSE:**

No, PowerStream does not propose that the amount and the timing of new long term debt would be subject to annual review. Such review would make the annual adjustment process more complicated and costly, and it is not necessary, as management decisions on the amount and timing of the new long term debt are affected by the timing of capital investment and factors outside of management control such as financial market conditions. In making the decision on the amount and timing of debt, PowerStream always attempts to minimize the overall cost of borrowing.

This approach is consistent with OEB decision on Horizon Rate Application (EB-2014-0002).

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**K-SEC-40**

**REF: Ex. K-1, p.3**

Please provide the basis for the forecasted rate of 4.5% for 2016-2018 long-term debt issuances.

**RESPONSE:**

The forecasted rate of 4.5% for 2016-2018 long-term debt issuance is a placeholder that would be subject to annual adjustments under Custom IR. This assumption has been used in PowerStream's budget and is based on long-term interest rate information. Weekly BMO indicative pricing updates for PowerStream in August/September 2014 (when the budget was prepared) showed that the all-in cost of a 30 year bond was in the 4.0% -4.2% range. It has been assumed that in 2016-2018 these rates may be slightly higher.

# EXHIBIT L: COST ALLOCATION

## L-Energy Probe-47

**REF: Ex. L, Tab 1, Table 2**

As shown in Table 2, the revenue to cost ratios for the residential, GS < 50 and USL classes are shown to be increasing over the 2016 through 2020 period, while the ratios for the GS>50, street lighting and sentinel lighting are decreasing over the period.

Moreover, the residential and GS < 50 ratios, which are at or above 100% are moving further away from 100%, while the ratios for the GS > 50, street lighting and sentinel lighting classes, which are below 100% are also moving further from 100% as well.

a) Please provide a revised Table 2 in which the residential class is held at the 2016 status quo ratio of 102.4%, the GS < 50 class is held at the 2016 status quo ratio of 99.9%, the large user class is held at 85%, the street lighting class is held at the 2016 status quo ratio of 91.3%, the sentinel class is held at the 2016 status quo ratio of 84.7% and the USL class is held at the 2016 status quo ratio of 88.13% for each of 2016 through 2020. Based on these constraints, what would the GS> 50 ratio be in each year?

b) Similar to the restraints in part (b), please provide a table that shows the impact on the residential ratio each year if the same constraints were in place as noted above, except instead of keeping the residential ratio at the 2016 status quo level, the GS > 50 ratio is kept at the 2016 status quo level over the period 2016 through 2020.

c) Please consider the scenario where all the revenue to cost ratios are maintained at the status quo 2016 levels, except that the Large Use class is initially increased to 85% and then the ratios of the lowest rate class are increased to the second lowest ratio and then both of these ratios are increased to the next lowest ratio, and so on, until sufficient revenue is generated to result in no deficiency or sufficiency. Please provide a version of Table 2 that makes this adjustment in each of the 2016 through 2020 years so that no revenue to cost ratios move further away from 100% in any year.

d) Based on each of the three scenarios noted above, please provide the monthly bill impacts (total bill and distribution portion) as shown in Tables 3 through 6 in Exhibit B, Tab 1.

**RESPONSE:**

a) Table L-EP-47-1 below presents the revised ratios as per requested scenario.

### Table L-EP-47-1: Appendix 2P (D) – Proposed Revenue-to-Cost Ratios

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | Revenue-to-Costs Ratios | | | | | | |
| | **2013 BA** | **2016** | **2017** | **2018** | **2019** | **2020** | **Policy Allowed Range** |
| **Residential** | **102.1%** | 102.4% | 102.4% | 102.4% | 102.4% | 102.4% | **85 - 115** |
| **GS Less Than 50 kW** | **98.0%** | 99.9% | 99.9% | 99.9% | 99.9% | 99.9% | **80 - 120** |
| **GS 50 to 4,999 kW** | **98.0%** | **96.64%** | **96.70%** | **96.77%** | **96.79%** | **96.85%** | **80 - 120** |
| **Large Use** | **85.0%** | 85.0% | 85.0% | 85.0% | 85.0% | 85.0% | **85 - 115** |
| **Unmetered Scattered Load** | **102.4%** | 91.3% | 91.3% | 91.3% | 93.1% | 93.1% | **80 - 120** |
| **Sentinel Lighting** | **95.0%** | 84.7% | 84.7% | 84.7% | 84.7% | 84.7% | **80 - 120** |
| **Street Lighting** | **89.7%** | 88.1% | 88.1% | 88.1% | 88.1% | 88.1% | **70 - 120** |

b) Table L-EP-47-2 below presents the revised ratios as per requested scenario.

### Table L-EP-47-2: Appendix 2P (D) – Proposed Revenue-to-Cost Ratios

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | Revenue-to-Costs Ratios | | | | | | |
| | **2013 BA** | **2016** | **2017** | **2018** | **2019** | **2020** | **Policy Allowed Range** |
| **Residential** | **102.1%** | **102.36%** | **102.46%** | **102.50%** | **102.51%** | **102.55%** | **85 - 115** |
| **GS Less Than 50 kW** | **98.0%** | 99.9% | 99.9% | 99.9% | 99.9% | 99.9% | **80 - 120** |
| **GS 50 to 4,999 kW** | **98.0%** | 96.6% | 96.6% | 96.6% | 96.6% | 96.6% | **80 - 120** |
| **Large Use** | **85.0%** | 85.0% | 85.0% | 85.0% | 85.0% | 85.0% | **85 - 115** |
| **Unmetered Scattered Load** | **102.4%** | 91.3% | 91.3% | 91.3% | 93.1% | 93.1% | **80 - 120** |
| **Sentinel Lighting** | **95.0%** | 84.7% | 84.7% | 84.7% | 84.7% | 84.7% | **80 - 120** |
| **Street Lighting** | **89.7%** | 88.1% | 88.1% | 88.1% | 88.1% | 88.1% | **70 - 120** |

c) Table L-EP-47-3 below presents the revised ratios as per requested scenario.

## Table L-EP-47-3: Appendix 2P (D) – Proposed Revenue-to-Cost Ratios

| | Revenue-to-Costs Ratios | | | | | | |
|---|---|---|---|---|---|---|---|
| | **2013 BA** | **2016** | **2017** | **2018** | **2019** | **2020** | **Policy Allowed Range** |
| **Residential** | **102.1%** | 102.4% | 102.4% | 102.4% | 102.4% | 102.4% | **85 - 115** |
| **GS Less Than 50 kW** | **98.0%** | 99.9% | 99.9% | 99.9% | 99.9% | 99.9% | **80 - 120** |
| **GS 50 to 4,999 kW** | **98.0%** | 96.6% | 96.6% | 96.6% | 96.6% | 96.6% | **80 - 120** |
| **Large Use** | **85.0%** | 85.0% | 89.3% | 90.5% | 90.8% | 92.0% | **85 - 115** |
| **Unmetered Scattered Load** | **102.4%** | 91.3% | 91.3% | 91.3% | 93.1% | 93.1% | **80 - 120** |
| **Sentinel Lighting** | **95.0%** | 84.7% | 89.3% | 90.5% | 90.8% | 92.0% | **80 - 120** |
| **Street Lighting** | **89.7%** | 88.1% | 89.3% | 90.5% | 90.8% | 92.0% | **70 - 120** |

d) Below are bill impact summaries based on each of the three scenarios.

<u>Scenario 1</u>

## Table L-EP-47-4: Summary of Monthly Bill Impacts for a Typical Customer – Total Bill (York Region)

| **Customer Class** | **Billing Determinant** | **Consumption per Customer (kWh)** | **Load per Customer (kW)** | **Total bill 2016** | **2017** | **2018** | **2019** | **2020** |
|---|---|---|---|---|---|---|---|---|
| Residential | kWh | 800 | | 4.0% | 2.0% | 0.9% | 0.4% | 0.9% |
| GS<50 kW | kWh | 2,000 | | 3.8% | 1.5% | 1.0% | 0.7% | 0.9% |
| GS>50 kW | kW | 80,000 | 250 | 3.5% | 1.5% | (0.1%) | 0.9% | 0.8% |
| Large Use | kW | 2,800,000 | 7,350 | 2.3% | 1.0% | 0.6% | 0.6% | 0.5% |
| Unmetered Scattered Load | kWh | 150 | | 5.6% | 1.4% | 0.5% | 1.6% | 0.6% |
| Sentinel Lights | kW | 180 | | 7.6% | 4.6% | 0.6% | 1.8% | 1.4% |
| Street Lighting | kW | 280 | | 5.5% | 5.5% | 4.1% | 2.0% | 1.9% |
| **Average** | | | | **4.6%** | **2.5%** | **1.1%** | **1.1%** | **1.0%** |

## Table L-EP-47-5: Summary of Monthly Bill Impacts for a Typical Customer – Distribution Portion (York Region)

| Customer Class | Billing Determinant | Consumption per Customer (kWh) | Load per Customer (kW) | Distribution Component 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|
| Residential | kWh | 800 | | 17.3% | 7.4% | 2.9% | 0.9% | 2.8% |
| GS<50 kW | kWh | 2,000 | | 17.4% | 6.1% | 3.2% | 2.3% | 2.9% |
| GS>50 kW | kW | 80,000 | 250 | 30.7% | 9.5% | (1.6%) | 4.8% | 4.0% |
| Large Use | kW | 2,800,000 | 7,350 | 29.4% | 9.1% | 4.0% | 3.8% | 3.1% |
| Unmetered Scattered Load | kWh | 150 | | 15.9% | 3.6% | 1.6% | 4.2% | 1.4% |
| Sentinel Lights | kW | 180 | | 21.6% | 11.6% | 1.1% | 4.1% | 3.1% |
| Street Lighting | kW | 280 | | 21.0% | 17.3% | 8.3% | 6.2% | 5.7% |
| **Average** | | | | **21.9%** | **9.2%** | **2.8%** | **3.8%** | **3.3%** |

## Table L-EP-47-6: Summary of Monthly Bill Impacts for a Typical Customer – Total Bill (Barrie Zone)

| Customer Class | Billing Determinant | Consumption per Customer (kWh) | Load per Customer (kW) | Total bill 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|
| Residential | kWh | 800 | | 3.9% | 2.0% | 0.9% | 0.4% | 0.9% |
| GS<50 kW | kWh | 2,000 | | 3.5% | 1.5% | 1.0% | 0.7% | 0.9% |
| GS>50 kW | kW | 80,000 | 250 | 3.5% | 1.5% | (0.1%) | 0.9% | 0.8% |
| Large Use | kW | 2,800,000 | 7,350 | 2.3% | 1.0% | 0.6% | 0.6% | 0.5% |
| Unmetered Scattered Load | kWh | 150 | | 5.6% | 1.4% | 0.5% | 1.6% | 0.6% |
| Sentinel Lights | kW | 180 | | | | | | |
| Street Lighting | kW | 280 | | 5.5% | 5.5% | 4.1% | 2.0% | 1.9% |
| **Average** | | | | **4.0%** | **2.1%** | **1.2%** | **1.0%** | **0.9%** |

## Table L-EP-47-7: Summary of Monthly Bill Impacts for a Typical Customer – Distribution Portion (Barrie Zone)

| Customer Class | Billing Determinant | Consumption per Customer (kWh) | Load per Customer (kW) | Distribution Component 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|
| Residential | kWh | 800 | | 16.6% | 7.4% | 2.9% | 0.9% | 2.8% |
| GS<50 kW | kWh | 2,000 | | 15.9% | 6.1% | 3.2% | 2.3% | 2.9% |
| GS>50 kW | kW | 80,000 | 250 | 30.4% | 9.5% | (1.6%) | 4.8% | 4.0% |
| Large Use | kW | 2,800,000 | 7,350 | 29.4% | 9.1% | 4.0% | 3.8% | 3.1% |
| Unmetered Scattered Load | kWh | 150 | | 15.9% | 3.6% | 1.6% | 4.2% | 1.4% |
| Sentinel Lights | kW | 180 | | | | | | |
| Street Lighting | kW | 280 | | 21.0% | 17.3% | 8.3% | 6.2% | 5.7% |
| **Average** | | | | **21.5%** | **8.8%** | **3.1%** | **3.7%** | **3.3%** |

## Scenario 2

### Table L-EP-47-8: Summary of Monthly Bill Impacts for a Typical Customer – Total Bill (York Region)

| Customer Class | Billing Determinant | Consumption per Customer (kWh) | Load per Customer (kW) | Total bill 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|
| Residential | kWh | 800 | | 4.0% | 2.0% | 0.9% | 0.4% | 0.9% |
| GS<50 kW | kWh | 2,000 | | 3.8% | 1.5% | 1.0% | 0.7% | 0.9% |
| GS>50 kW | kW | 80,000 | 250 | 3.5% | 1.5% | (0.1%) | 0.9% | 0.8% |
| Large Use | kW | 2,800,000 | 7,350 | 2.3% | 1.0% | 0.6% | 0.6% | 0.5% |
| Unmetered Scattered Load | kWh | 150 | | 5.6% | 1.4% | 0.5% | 1.6% | 0.6% |
| Sentinel Lights | kW | 180 | | 7.6% | 4.6% | 0.6% | 1.8% | 1.4% |
| Street Lighting | kW | 280 | | 5.5% | 5.5% | 4.1% | 2.0% | 1.9% |
| **Average** | | | | **4.6%** | **2.5%** | **1.1%** | **1.1%** | **1.0%** |

### Table L-EP-47-9: Summary of Monthly Bill Impacts for a Typical Customer – Distribution Portion (York Region)

| Customer Class | Billing Determinant | Consumption per Customer (kWh) | Load per Customer (kW) | Distribution Component 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|
| Residential | kWh | 800 | | 17.3% | 7.5% | 2.9% | 0.9% | 2.8% |
| GS<50 kW | kWh | 2,000 | | 17.4% | 6.1% | 3.2% | 2.3% | 2.9% |
| GS>50 kW | kW | 80,000 | 250 | 30.7% | 9.4% | (1.6%) | 4.8% | 3.9% |
| Large Use | kW | 2,800,000 | 7,350 | 29.4% | 9.1% | 4.0% | 3.8% | 3.1% |
| Unmetered Scattered Load | kWh | 150 | | 15.9% | 3.6% | 1.6% | 4.2% | 1.4% |
| Sentinel Lights | kW | 180 | | 21.6% | 11.6% | 1.1% | 4.1% | 3.1% |
| Street Lighting | kW | 280 | | 21.0% | 17.3% | 8.3% | 6.2% | 5.7% |
| **Average** | | | | **21.9%** | **9.2%** | **2.8%** | **3.8%** | **3.3%** |

**Table L-EP-47-10: Summary of Monthly Bill Impacts for a Typical Customer – Total Bill (Barrie Zone)**

| Customer Class | Billing Determinant | Consumption per Customer (kWh) | Load per Customer (kW) | Total bill 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|
| Residential | kWh | 800 | | 3.9% | 2.0% | 0.9% | 0.4% | 0.9% |
| GS<50 kW | kWh | 2,000 | | 3.5% | 1.5% | 1.0% | 0.7% | 0.9% |
| GS>50 kW | kW | 80,000 | 250 | 3.5% | 1.5% | (0.1%) | 0.9% | 0.8% |
| Large Use | kW | 2,800,000 | 7,350 | 2.3% | 1.0% | 0.6% | 0.6% | 0.5% |
| Unmetered Scattered Load | kWh | 150 | | 5.6% | 1.4% | 0.5% | 1.6% | 0.6% |
| Sentinel Lights | kW | 180 | | | | | | |
| Street Lighting | kW | 280 | | 5.5% | 5.5% | 4.1% | 2.0% | 1.9% |
| **Average** | | | | **4.0%** | **2.1%** | **1.2%** | **1.0%** | **0.9%** |

**Table L-EP-47-11: Summary of Monthly Bill Impacts for a Typical Customer – Distribution Portion (Barrie Zone)**

| Customer Class | Billing Determinant | Consumption per Customer (kWh) | Load per Customer (kW) | Distribution Component 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|
| Residential | kWh | 800 | | 16.6% | 7.5% | 2.9% | 0.9% | 2.8% |
| GS<50 kW | kWh | 2,000 | | 15.9% | 6.1% | 3.2% | 2.3% | 2.9% |
| GS>50 kW | kW | 80,000 | 250 | 30.4% | 9.4% | (1.6%) | 4.8% | 3.9% |
| Large Use | kW | 2,800,000 | 7,350 | 29.4% | 9.1% | 4.0% | 3.8% | 3.1% |
| Unmetered Scattered Load | kWh | 150 | | 15.9% | 3.6% | 1.6% | 4.2% | 1.4% |
| Sentinel Lights | kW | 180 | | | | | | |
| Street Lighting | kW | 280 | | 21.0% | 17.3% | 8.3% | 6.2% | 5.7% |
| **Average** | | | | **21.5%** | **8.8%** | **3.1%** | **3.7%** | **3.3%** |

Scenario 3

**Table L-EP-47-12: Summary of Monthly Bill Impacts for a Typical Customer – Total Bill (York Region)**

| Customer Class | Billing Determinant | Consumption per Customer (kWh) | Load per Customer (kW) | Total bill 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|
| Residential | kWh | 800 | | 4.0% | 2.0% | 0.9% | 0.4% | 0.9% |
| GS<50 kW | kWh | 2,000 | | 3.8% | 1.5% | 1.0% | 0.7% | 0.9% |
| GS>50 kW | kW | 80,000 | 250 | 3.5% | 1.5% | (0.1%) | 0.9% | 0.8% |
| Large Use | kW | 2,800,000 | 7,350 | 2.3% | 1.3% | 0.7% | 0.6% | 0.6% |
| Unmetered Scattered Load | kWh | 150 | | 5.6% | 1.4% | 0.5% | 1.6% | 0.6% |
| Sentinel Lights | kW | 180 | | 7.6% | 7.0% | 1.2% | 2.1% | 2.1% |
| Street Lighting | kW | 280 | | 5.5% | 5.8% | 4.5% | 2.1% | 2.4% |
| **Average** | | | | **4.6%** | **2.9%** | **1.2%** | **1.2%** | **1.2%** |

## Table L-EP-47-13: Summary of Monthly Bill Impacts for a Typical Customer – Distribution Portion (York Region)

| Customer Class | Billing Determinant | Consumption per Customer (kWh) | Load per Customer (kW) | Distribution Component 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|
| Residential | kWh | 800 | | 17.3% | 7.4% | 2.9% | 0.9% | 2.8% |
| GS<50 kW | kWh | 2,000 | | 17.4% | 6.1% | 3.2% | 2.3% | 2.9% |
| GS>50 kW | kW | 80,000 | 250 | 30.7% | 9.4% | (1.6%) | 4.8% | 3.9% |
| Large Use | kW | 2,800,000 | 7,350 | 29.4% | 12.5% | 4.9% | 4.2% | 4.0% |
| Unmetered Scattered Load | kWh | 150 | | 15.9% | 3.6% | 1.6% | 4.2% | 1.4% |
| Sentinel Lights | kW | 180 | | 21.6% | 17.7% | 2.6% | 4.5% | 4.4% |
| Street Lighting | kW | 280 | | 21.0% | 18.9% | 9.6% | 6.6% | 7.0% |
| **Average** | | | | **21.9%** | **10.8%** | **3.3%** | **3.9%** | **3.8%** |

## Table L-EP-47-14: Summary of Monthly Bill Impacts for a Typical Customer – Total Bill (Barrie Zone)

| Customer Class | Billing Determinant | Consumption per Customer (kWh) | Load per Customer (kW) | Total bill 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|
| Residential | kWh | 800 | | 3.9% | 2.0% | 0.9% | 0.4% | 0.9% |
| GS<50 kW | kWh | 2,000 | | 3.5% | 1.5% | 1.0% | 0.7% | 0.9% |
| GS>50 kW | kW | 80,000 | 250 | 3.5% | 1.5% | (0.1%) | 0.9% | 0.8% |
| Large Use | kW | 2,800,000 | 7,350 | 2.3% | 1.3% | 0.7% | 0.6% | 0.6% |
| Unmetered Scattered Load | kWh | 150 | | 5.6% | 1.4% | 0.5% | 1.6% | 0.6% |
| Sentinel Lights | kW | 180 | | | | | | |
| Street Lighting | kW | 280 | | 5.5% | 5.8% | 4.5% | 2.1% | 2.4% |
| **Average** | | | | **4.0%** | **2.2%** | **1.2%** | **1.1%** | **1.0%** |

## Table L-EP-47-15: Summary of Monthly Bill Impacts for a Typical Customer – Distribution Portion (Barrie Zone)

| Customer Class | Billing Determinant | Consumption per Customer (kWh) | Load per Customer (kW) | Distribution Component 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|
| Residential | kWh | 800 | | 16.6% | 7.4% | 2.9% | 0.9% | 2.8% |
| GS<50 kW | kWh | 2,000 | | 15.9% | 6.1% | 3.2% | 2.3% | 2.9% |
| GS>50 kW | kW | 80,000 | 250 | 30.4% | 9.4% | (1.6%) | 4.8% | 3.9% |
| Large Use | kW | 2,800,000 | 7,350 | 29.4% | 12.5% | 4.9% | 4.2% | 4.0% |
| Unmetered Scattered Load | kWh | 150 | | 15.9% | 3.6% | 1.6% | 4.2% | 1.4% |
| Sentinel Lights | kW | 180 | | | | | | |
| Street Lighting | kW | 280 | | 21.0% | 18.9% | 9.6% | 6.6% | 7.0% |
| **Average** | | | | **21.5%** | **9.7%** | **3.4%** | **3.8%** | **3.7%** |

**L-Energy Probe-48**

**REF: Ex. L, Tab 1, page 1**

a) Please provide any report, study, or other document that deals with the updating of the load profile for the test year load forecasts.

b) Were all of the rate class load profiles re-scaled based on the forecasts, or were some rate classes updated with new load profiles based on recent historical information? If the latter, please provide a summary of the data used and the rate classes for which new load profiles were derived.

c) Please provide a summary, by rate class, that shows the change in the allocation of costs between rate classes as a result of any new load profiles identified in the response to part (b) above.

**RESPONSE:**

a) No report, study, or other document has been prepared that deals with the updating of the load profile for the test year load forecasts. The process for updating the load profile is to start with the most recent weather normal profile available, and scale that profile to the expected load in the test year.

Small volume rate classes tend to be weather sensitive. Further, where classes consist of large numbers of smaller customers, customer turnover, and changes in the behavior of individual customers is not likely to materially affect the load shape for the class taken as a whole. For that reason, a historic weather normalized profile is used for all customer classes except Large Use.

Large volume rate classes are typically not materially weather sensitive. In addition, customer turnover, and changes in the behavior of individual customers can materially affect the load shape for the class taken as a whole. For that reason, a recent load profile is preferred. Given the relatively small number of Large Use customers, updated profiles are relatively inexpensive and easy to obtain.

b) The Large User rate class was updated with load profiles based on 2013 actual information. The remaining rate classes were based on profiles from the last cost of service application. All rate classes were then scaled from their respective sources to 2016, 2017, 2018, 2019, and 2020 forecasts.

c) Had the load profile from the previous cost of service been used for Large Use, and scaled to 2016 – as had been done for the other rate classes, the following Table 1 outlines the change in costs allocated.

**Table L-EP-48-1: Allocation Comparison New Load Profiles vs. Previous Load Profiles**

| Rate Class | As Filed | Scaling of Old Profiles only | Difference |
|---|---|---|---|
| Residential | 107,541,142 | 107,541,783 | 641 |
| GS < 50 | 31,390,105 | 31,390,509 | 404 |
| GS > 50 | 59,651,940 | 59,653,399 | 1,459 |
| Large User | 456,887 | 454,347 | (2,540) |
| Street Lights | 3,333,170 | 3,333,203 | 33 |
| Sentinel | 24,453 | 24,453 | 0 |
| Unmetered Scattered Load | 680,197 | 680,200 | 3 |
| **Total** | **203,077,894** | **203,077,894** | **0** |

**L-SEC-41**

**REF: Ex. L-1, p.1**

Please provide a copy of the Cost Allocation Study referred to on line 4.

**RESPONSE:**

The Cost Allocation Study referred to on line 4 of Exhibit L represents Cost Allocation Models for each of the five test years using the Board's v 3.2 Cost Allocation Model ("Board 3.2 CA Model").

Live excel versions of the 2016 – 2020 Cost Allocation models have been provided as supplementary information in electronic Appendix L-1-2.

**L-VECC-33**

**REF: Ex. L/T-1/pg. 1**

a) In terms of the updating to the load profiles please identify those customer classes for which the load profiles used in the 2013 COS application were simply re-scaled to the new GWh load forecast versus those classes for which a "new" load profile was established.

b) For each of the customer classes in the latter case, please explain the basis for the "new" load profile.

**RESPONSE:**

a) The load profiles for the following rate classes were scaled based on the change in GWHs from what had been used in the 2013 rate application:
- Residential;
- GS < 50;
- GS > 50;
- Street Lighting;
- Sentinel Lighting;
- Unmetered Scattered Load.

A new load profile was created for the Large Use customer class.

b) The Large Use class load profile was based on 2013 actual interval meter data, and then scaled to forecast GWH. Neither of the customers in this class are significantly weather-sensitive, nor expected to have significant changes in their energy use that would materially impact the suitability of 2013 actual data.

**L-VECC-34**

**REF: Ex. L/T-1/pg. 2**

a) Please explain why, contrary to Board policy (EB-2007-0667 Report, page 7) the proposed revenue to cost ratios for some customer classes are moving away from 100% over the test years.

**RESPONSE:**

a) PowerStream is proposing Status Quo rate increases through the Custom IR period, except where adjustments are required to stay within the OEB target ranges. This approach does not contribute to the revenue to cost ratio of any rate class moving away from unity.

Where Revenue-to-Cost ratios are moving away from unity, this is a result of changes in the allocated costs, and not due to changes in relative rates, or any attempt to re-balance Revenue-to-Cost ratios.

The Revenue-to-Cost ratio for Large Use Rates at status quo rates falls below the OEB target range requiring a re-allocation of additional revenue requirement to be collected from this class. The amount of additional revenue allocated to the Large Use class has been deducted from the Residential class. The effect of this adjustment raises the Large Use class Revenue-to-Cost ratio to within the OEB Target range and lowers the Residential class Revenue to Cost ratio, which is above 1, closer to unity.

On page 6, section 2.3.4 of the EB-2007-0667 report, the Board speaks to the desirability of rate stability. These changes are the result of some inherent variability in Revenue-to-Cost ratios when the same methodology is applied due to changes in investment in infrastructure, load forecasts, and operational activities. PowerStream does not propose to adjust Revenue-to-Cost ratios which are within the OEB target range.

**L-VECC-35**

**Reference: E-L/Cost Allocation Models (2016-2020)**

Preamble: It is noted that in the Proposal's Cost Allocation models, the Meter Reading Tab (I-7.2) includes suite meters as well as smart meters for the Residential class – whereas the cost allocation used in the 2013 COSS Application included only smart meters.

a) Please explain how Power Stream forecast the number of Residential customers with smart meters as opposed to suite meters for each of the test years and provide the split for each year.

b) Please explain the change in meter reading categories used in Tab I7.2 as between the 2013 COSS Application and the current Proposal.

c) Please explain how the cost/unit for each of the different meter reading categories was established.

d) Please explain, for each customer class, how the number of meters by type as shown in Tab I-7.1 was translated into the number of meter reads by type shown in Tab I-7.2.

**RESPONSE:**

a) The 2014 actual customer counts for smart meters and suite meters were used as a base for determining the bridge year and test year quantities. The number of customers with suite meters was held constant due to uncertainty regarding the retention of current suite meter customers and the addition of new customers in future years. Table L-VECC-35-1 shows the split between customers with smart meters and those with suite meters.

**Table L-VECC-35-1: Residential Smart Meter and Suite Metered Customers**

| | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|
| Smart Meter customers | 314,190 | 320,307 | 326,537 | 332,798 | 339,202 |
| Suite Meter customers | 11,569 | 11,569 | 11,569 | 11,569 | 11,569 |
| Total Residential Class | 325,759 | 331,876 | 338,106 | 344,367 | 350,771 |

b) A review of the meter reading categories for this application concluded that all residential class customers are read electronically whether they have a smart meter or a suite meter. The process and associated cost for suite meter readings are different from smart meters. Therefore a new category for suite meters was established for this rate proposal.

c) PowerStream the cost components to complete a meter read for each meter category. Typical 2014 invoices were used to determine the unit cost for the meter reading activity.

Internal labour is required for a number of interval meter reads. The meter department provided the duration and vehicle times. PowerStream standard rates were applied.

See below table L-VECC-35-2 for a summary of the unit cost components.

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1 **Table L-VECC-35-2: Meter Reading Cost Components**

| Meter Read Category | Basic read Type | Primary Data Collection / Conversion System | Meter Read Labour | Meter Read Vehicle | Overhead Applied to Labour | Notes |
|---|---|---|---|---|---|---|
| Smart Meters | Electronic | ODS and MDMR | not applicable | not applicable | not applicable | **1** |
| Suite meters | Electronic and Manual | ODS | Contractor on Manual reads | included | included | **2** |
| GS>50 Normal manual | manual | not applicable | Contractor | included | included | **3** |
| GS>50 Special reads | manual | not applicable | Contractor | included | included | **4** |
| Interval Electronic | Electronic | MV90 | PS MV90 administrator | not applicable | not applicable | **5** |
| Interval Manual | manual | not applicable | PS Staff | Applies | Applies | **6** |

Notes:

1) Sensus engaged to carry out the automated reading of meters and monitoring data transfer. Savage Data Systems provides the data conversion. Util- Assist provides the sync operator and testing services.

2) Savage Data Systems engaged to provide the processing and meter data conversion. Trilliant Energy services provides interrogation and manual re-reads due to electronic communication errors

3) Olameter engaged to carry out routine manual reads

4) Olameter engaged to carry out special reads which entails requested call backs, final, specific appointments

| |
|---|
| 5) Itron engaged to support data transfers and internal full time staff to administer MV90 system<br><br>6) Internal metering staff required to obtain data manually from interval meters. |

The process and costs for meter reading are similar for all smart meters regardless of the type of smart meter. The process and costs for meter reading are similar for all suite meters, regardless of the type of suite meter.

d) The number of meter reads are determined by multiplying the number of customers for each type of meter read (i.e. smart meter or suite meter) by the billing frequency (i.e. 6 times a year for Residential, 12 times a year for all other customer classes) and adding a small factor for other meter reads which occur for various reasons such as change in occupancy.

In responding to this question it was determined that the number of meter readings for suite meters was not calculated in this manner and need to be restated. The restated counts are shown in Table L-VECC-35-3 below.

**Table L- VECC-35- 3: Restated Residential Meter Reads**

| | **2016** | **2017** | **2018** | **2019** | **2020** |
|---|---|---|---|---|---|
| Customer Count [ I6.2] | 325,759 | 331,876 | 338,106 | 344,367 | 350,771 |
| | | | | | |
| Smart meters Reads [I7.2] | 1,886,797 | 1,923,374 | 1,960,627 | 1,998,066 | 2,036,356 |
| Adjusted Suite meter Reads [ I7.2] | 72,765 | 72,765 | 72,765 | 72,765 | 72,765 |
| Total Residential Reads | 1,959,562 | 1,996,139 | 2,033,392 | 2,070,831 | 2,109,121 |
| Ratio - Total Reads to Customer Count | 6.02 | 6.01 | 6.01 | 6.01 | 6.01 |

The change is small and is not expected to have any impact on cost allocation. This will be addressed when PowerStream provides an update after the technical conference.

In responding to this question, PowerStream also noted that the number of customers was used on the Meter Capital sheet I7.1 for suite meters rather than the number of meters. The number of meters is different than the number of customers as the suite meter used in Residential condominiums can meter multiple customers. Based on this information it is necessary to update the suite meter information on I7.1. This will be addressed when PowerStream provides an update after the technical conference.

## L-VECC-36

## REF: Ex. L/Cost Allocation Models (2016-2020)

a) Please explain why the customer counts shown in Exhibit H/Tab 4/Table 7 don't match the customer counts in Tab I-6.2 of the cost allocation models.

b) There are also some slight discrepancies between the volumetric billing determinants shown in Table 6 and those used in the cost allocation models. Please reconcile.

c) Please explain why the number of meters by customer class used in the 2016-2020 Cost Allocation models (Tab I-7.1) does not equal the number of customers in each class as shown Table 7.

## RESPONSE:

a) Customer counts shows in Exhibit H/Tab 4/Table 7 are year-end values as of December 31, while customer counts in Exhibit L/Cost Allocation Model/Tab I-6.2 represent a 12-month average January through December values for each year. Table 1 below demonstrates the 2016 reconciliation.

**Table 1: 2016 Customer Count**

| | 2016 | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | 2016 FY |
| | Fcst | Fcst | Fcst | Fcst | Fcst | Fcst | Fcst | Fcst | Fcst | Fcst | Fcst | Fcst | |
| Residential | 323,639 | 324,020 | 324,402 | 324,785 | 325,170 | 325,556 | 325,944 | 326,333 | 326,725 | 327,117 | 327,511 | 327,907 | 325,759 |
| GS<50 | 32,258 | 32,288 | 32,318 | 32,348 | 32,379 | 32,409 | 32,440 | 32,471 | 32,501 | 32,532 | 32,563 | 32,594 | 32,425 |
| GS>50 | 4,902 | 4,910 | 4,920 | 4,929 | 4,939 | 4,948 | 4,957 | 4,967 | 4,977 | 4,986 | 4,996 | 5,005 | 4,953 |
| Time of use | - | - | - | - | - | - | - | - | - | - | - | - | |
| Large Use | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| USL | 2,948 | 2,953 | 2,958 | 2,963 | 2,968 | 2,973 | 2,978 | 2,984 | 2,989 | 2,995 | 3,000 | 3,006 | 2,976 |
| Sentinel Lighting | 209 | 209 | 209 | 209 | 209 | 209 | 209 | 209 | 209 | 207 | 207 | 207 | 208 |
| Street Lighting | 87,506 | 87,636 | 87,766 | 87,896 | 88,027 | 88,158 | 88,290 | 88,422 | 88,554 | 88,687 | 88,820 | 88,953 | 88,226 |
| Total | 451,464 | 452,018 | 452,575 | 453,133 | 453,694 | 454,255 | 454,821 | 455,388 | 455,956 | 456,526 | 457,098 | 457,674 | **454,550** |

b) The discrepancies between volumetric billing determinants shown in Table 6 and those used in the cost allocation models are exclusively related to GS < 50 kW load and it is due to rounding, as shown in the table below.

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| Year | Cost Allocation Model (kWh) | Billing Determinates (kWh) | Difference (kWh) |
|---|---|---|---|
| 2015 | 1,041,113,005 | 1,041,113,015 | (10) |
| 2016 | 1,040,222,607 | 1,040,222,617 | (10) |
| 2017 | 1,034,670,626 | 1,034,670,636 | (10) |
| 2018 | 1,029,394,754 | 1,029,394,734 | 20 |
| 2019 | 1,023,938,204 | 1,023,938,194 | 10 |
| 2020 | 1,020,971,584 | 1,020,971,574 | 10 |

c) Customer counts shows in Exhibit H/Tab 4/Table 7 are year-end values as of December 31, while customer counts in Exhibit L/Cost Allocation Model/Tab I-7.1 uses the average number of customers for each year.

**L-VECC-37**

**REF: Ex. L/Cost Allocation Models (2016-2020)**

a) Do all the buildings with PowerStream's Residential suite metered customers utilize Power Stream's transformers and secondary distribution system? If not, in Tab I-6.2, why are all the Residential customers assumed to be served using PowerStream's transformers and secondary distribution system?

b) Please revise Tab I-6.2 of the 2016-2020 Cost Allocation models as necessary.

**RESPONSE:**

a) Further analysis determined that all suite meter buildings have secondary services that are not owned by PowerStream. All suite metered buildings have transformers that are owned by PowerStream. Accordingly PowerStream will adjust the Cost allocation model Tab I6.2 to remove the suite metered customers from the secondary customer base for the residential class. The Residential Class Secondary customer base will be updates as shown in Table L-VECC-37-1 below.

**Table L-VECC-37-1: Update to I6.2 Secondary Customer Base - Residential**

| | **2016** | **2017** | **2018** | **2019** | **2020** |
|---|---|---|---|---|---|
| Secondary Customer Base | 314,190 | 320,307 | 326,537 | 332,798 | 339,202 |

b) PowerStream will provide a full update that incorporates this correction following the technical conference.

# EXHIBIT M: RATE DESIGN

## M-AMPCO-30

## REF: Ex. M-Tab 1

a) Pages 1-2: For the GS>50 kW and Large User customer classes, please provide the monthly fixed charge and variable rate for 2016 to 2010 if the fixed/ variable split is maintained at the 2013 Board-Approved Fixed/Variable Split for each customer class.

## RESPONSE:

a) PowerStream performed the following calculations to derive 2016-2020 monthly fixed and variable rates under the requested scenario - if the fixed/ variable split is maintained at the 2013 Board-Approved Fixed/Variable Split for each customer class:

Step 1: Allocate Revenue Requirement as based on the 2013 Board-approved split between fixed and variable distribution revenue.

**Table 1: 2016 Revenue Requirement Allocations (Fixed/Variable)**

| 2016 BRR Revenue to be Allocated $191,447,176 | Allocation to customer classes, % | Allocation between Fixed and Variable Revenue 2013 Board-Approved | | | Revenue Requirement Allocation | | |
|---|---|---|---|---|---|---|---|
| | Total for Class (%) | Variable % | Fixed % | Total % | Total ($) | Variable $ | Fixed $ |
| Residential | 54.16% | 44.9% | 55.1% | 100.0% | 103,692,720 | 46,574,197 | 57,118,524 |
| GS<50 | 15.15% | 59.8% | 40.2% | 100.0% | 29,000,156 | 17,352,505 | 11,647,652 |
| GS>50 | 28.76% | 83.1% | 16.9% | 100.0% | 55,063,699 | 45,748,687 | 9,315,012 |
| Large Use | 0.20% | 51.3% | 48.7% | 100.0% | 376,268 | 192,919 | 183,349 |
| USL | 0.29% | 46.5% | 53.5% | 100.0% | 560,585 | 260,620 | 299,965 |
| Sentinel Lighting | 0.01% | 67.0% | 33.0% | 100.0% | 19,269 | 12,905 | 6,364 |
| Street Lighting | 1.43% | 48.4% | 51.6% | 100.0% | 2,734,479 | 1,324,822 | 1,409,656 |
| Total | 100.0% | 58.2% | 41.8% | 100.0% | 191,447,176 | 111,466,655 | 79,980,522 |

Step 2: Derive Fixed Rate.

For each year, where the current 2015 Monthly Service Charge (MSC) is at or above the ceiling, the proposed MSC has been capped at the 2015 MSC. Otherwise, the proposed MSC has been determined as the lower of the calculated MSC (calculated at the current fixed-variable revenue split) and the ceiling.

### Table 2: Calculation of Monthly Service Charge

| | | | | Cost Allocation Model 2016 | | | |
|---|---|---|---|---|---|---|---|
| | Fixed $ | Customer Count | Fixed Rate | Floor | Ceiling | Current Rate 2015 IRM | **Final Rate** |
| | A | B | A / B / 12 | | | | C |
| Residential | 57,118,524 | 325,759 | $ 14.61 | $ 4.68 | $ 16.71 | $ 12.67 | **$ 14.61** |
| GS<50 | 11,647,652 | 32,425 | $ 29.93 | $ 14.98 | $ 33.30 | $ 26.08 | **$ 29.93** |
| GS>50 | 9,315,012 | 4,953 | $ 156.72 | $ 51.24 | $ 123.91 | $ 138.48 | **$ 138.48** |
| Large Use | 183,349 | 2 | $ 7,639.53 | $ 345.22 | $ 675.83 | $ 5,966.29 | **$ 5,966.29** |
| USL | 299,965 | 2,976 | $ 8.40 | $ 4.30 | $ 14.78 | $ 7.01 | **$ 8.40** |
| Sentinel Lighting | 6,364 | 208 | $ 2.54 | $ 0.81 | $ 7.03 | $ 3.41 | **$ 2.54** |
| Street Lighting | 1,409,656 | 88,226 | $ 1.33 | $ 0.62 | $ 6.78 | $ 1.26 | **$ 1.33** |
| **Total** | **79,980,522** | **454,550** | | | | | |

Step 3: Derive Variable Rate

Once the MSC for each class is determined, the fixed distribution revenue from the MSC is calculated and subtracted from the total class revenue allocation. The remainder is the variable distribution revenue for the class. This variable distribution revenue value is then used to determine the variable charge.

### Table 3: Calculation of Variable Rate

| | Total ($) | Fixed $ | Variable $ | kWh | kW | **Final Rate, KWh** | Rate, KW | Transformer Allowance | **Final Rate, KW** |
|---|---|---|---|---|---|---|---|---|---|
| | A | B | C = A - B | | | | | | |
| Residential | 103,692,720 | 57,118,524 | 46,574,197 | 2,750,618,680 | - | **$ 0.0169** | | | |
| GS<50 | 29,000,156 | 11,647,652 | 17,352,505 | 1,040,222,607 | - | **$ 0.0167** | | | |
| GS>50 | 55,063,699 | 8,230,788 | 46,832,911 | 4,574,077,591 | 12,212,781 | | $ 3.8347 | $ 0.1761 | **$ 4.0108** |
| Large Use | 376,268 | 143,191 | 233,077 | 76,536,992 | 150,807 | | $ 1.5455 | $ 0.6000 | **$ 2.1455** |
| USL | 560,585 | 299,965 | 260,620 | 14,169,725 | - | **$ 0.0184** | | | **$ -** |
| Sentinel Lighting | 19,269 | 6,364 | 12,905 | 378,080 | 975 | | $ 13.2326 | | **$ 13.2326** |
| Street Lighting | 2,734,479 | 1,409,656 | 1,324,822 | 53,007,707 | 148,205 | | $ 8.9391 | | **$ 8.9391** |
| **Total** | **191,447,176** | **78,856,140** | **112,591,037** | **8,509,011,382** | **12,512,768** | | | | |

The above process was repeated for each year 2017 to 2020. The resulting rates as compared to the Current Proposed are presented in Tables 4 and 5 below.

### Table 4: Fixed and Variable Rate under the Test Scenario

| | 2016 | | 2017 | | 2018 | | 2019 | | 2020 | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Fixed | Variable | Fixed | Variable | Fixed | Variable | Fixed | Variable | Fixed | Variable |
| Residential | $ 14.61 | $ 0.0169 | $ 15.78 | $ 0.0187 | $ 16.34 | $ 0.0198 | $ 16.87 | $ 0.0208 | $ 17.29 | $ 0.0219 |
| GS<50 | $ 29.93 | $ 0.0167 | $ 32.34 | $ 0.0183 | $ 33.46 | $ 0.0193 | $ 34.51 | $ 0.0202 | $ 35.43 | $ 0.0211 |
| **GS>50** | **$ 138.48** | **$ 4.0108** | **$ 138.48** | **$ 4.4248** | **$ 138.48** | **$ 4.6509** | **$ 138.48** | **$ 4.8735** | **$ 138.48** | **$ 5.0712** |
| **Large Use** | **$ 5,966.29** | **$ 2.1455** | **$ 5,966.29** | **$ 2.4901** | **$ 5,966.29** | **$ 2.6930** | **$ 5,966.29** | **$ 2.8778** | **$ 5,966.29** | **$ 3.0387** |
| USL | $ 8.40 | $ 0.0184 | $ 9.18 | $ 0.0200 | $ 9.59 | $ 0.0209 | $ 9.98 | $ 0.0218 | $ 10.31 | $ 0.0226 |
| Sentinel Lighting | $ 2.54 | $ 13.2326 | $ 2.78 | $ 14.3858 | $ 2.91 | $ 15.0302 | $ 3.03 | $ 15.6569 | $ 3.14 | $ 16.2068 |
| Street Lighting | $ 1.33 | $ 8.9391 | $ 1.36 | $ 10.7285 | $ 1.32 | $ 12.6897 | $ 1.37 | $ 13.4644 | $ 1.40 | $ 14.2417 |

## Table 5: Current Proposed Fixed and Variable Rates

| | 2016 | | 2017 | | 2018 | | 2019 | | 2020 | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Fixed | Variable | Fixed | Variable | Fixed | Variable | Fixed | Variable | Fixed | Variable |
| Residential | $ 14.58 | $ 0.0170 | $ 15.70 | $ 0.0188 | $ 16.19 | $ 0.0200 | $ 16.66 | $ 0.0212 | $ 17.04 | $ 0.0223 |
| GS<50 | $ 30.01 | $ 0.0167 | $ 32.55 | $ 0.0182 | $ 33.10 | $ 0.0194 | $ 33.20 | $ 0.0207 | $ 33.37 | $ 0.0219 |
| **GS>50** | **$ 138.48** | **$ 4.0108** | **$ 138.48** | **$ 4.4248** | **$ 138.48** | **$ 4.6509** | **$ 138.48** | **$ 4.8735** | **$ 138.48** | **$ 5.0712** |
| **Large Use** | **$ 5,966.29** | **$ 2.1455** | **$ 5,966.29** | **$ 2.4901** | **$ 5,966.29** | **$ 2.6930** | **$ 5,966.29** | **$ 2.8778** | **$ 5,966.29** | **$ 3.0387** |
| USL | $ 8.07 | $ 0.0192 | $ 8.65 | $ 0.0214 | $ 8.87 | $ 0.0227 | $ 9.03 | $ 0.0242 | $ 9.12 | $ 0.0256 |
| Sentinel Lighting | $ 3.92 | $ 9.7021 | $ 4.33 | $ 10.4450 | $ 4.56 | $ 10.8193 | $ 4.77 | $ 11.2191 | $ 4.97 | $ 11.5304 |
| Street Lighting | $ 1.45 | $ 8.0925 | $ 1.56 | $ 9.0580 | $ 1.61 | $ 9.7775 | $ 1.66 | $ 10.3887 | $ 1.70 | $ 10.9884 |

The proposed MSC under the test scenario has been capped at the 2015 MSC, which is consistent with the Current Proposed Rates. As a result, there is no change in fixed and variable rates for GS>50 and Large Use rate classification, under the test scenario where the fixed/variable split is maintained at the 2013 Board-Approved Fixed/Variable Split for each customer class.

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**M-Energy Probe-49**

**REF: Ex. M, Tab 5**

a) Please explain why PowerStream has used a 3 year average instead of a 5 year average in the calculation of the loss factors.

b) Please provide a version of Appendix 2-R that shows a five year average calculated using 2009 through 2013 data, as well as a version that used 2010 through 2014 data.

c) Please provide a version of Appendix 2-R that shows a three year average but replaces 2011 through 2013 with 2012 through 2014.

d) Does PowerStream propose to update the loss factors as part of the annual adjustment process? If not, please explain why not.

**RESPONSE:**

a) As per section 2.11.9 Loss Adjustment Factors in the Filing Requirement from the Board (July 18, 2014), a minimum filing of three years of data is required, although five years of historical data is preferred. PowerStream has used a 3 year average to meet the filing requirement.

b) Please refer to M-Energy Probe-49 Appendix B for five year average Line Loss calculation using 2009 -2013 data, as well as 2010-2014 data.

c) Please refer to M-Energy Probe-49 Appendix C for three year average with the replacement from 2011-2013 to 2012-2014.

d) Yes. PowerStream proposes to update the loss factors as part of the annual adjustment process.

**M-VECC-38**

**REF: Ex. M/T-4/pg. 1-2**

a) With respect to the proposed LV charges, does PowerStream proposed to update these values to reflect any updates to HONI's approved ST Rates or is it seeking to set the rates at those laid out tin Table 3.

**RESPONSE:**

a) PowerStream is proposing to update the proposed LV charges, as presented in Exhibit M/Tab/Table 3, to reflect future updates to HONI's approved ST rates.

**M-VECC-39**

**REF: Ex. M/T-5/pg. 1-2**

a) Please explain why PowerStream has used three years of historical data to calculate the loss factors as opposed five years as preferred by the Filing Guidelines (Section 2.11.9).

**RESPONSE:**

a) Please refer to M-Energy Probe – 49.

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# EXHIBIT N: DEFERRAL AND VARIANCE ACCOUNTS

**N-CCC-63**

**REF:Ex. N/T1/S1/p. 1**

Please explain why there is a significant balance recorded in Account 1589 - Global Adjustment. What is this attributed to?

**RESPONSE:**

The December 31, 2014 closing balance in global adjustment account 1589 is a net under recovery of $10.3 million from global adjustment variances arising in 2013 and 2014.

The Independent Electricity System Operator (IESO) provides the Global Adjustment 1st Estimate rate at the beginning of the month and this is the rate that PowerStream uses to bill most of its customers. PowerStream pays IESO the actual global adjustment rate which appears on the IESO invoice received about the middle of the following month.

The average Global Adjustment rate that PowerStream billed to its ratepayers ($56.84 per MWh) was less than the average Global Adjustment rate that PowerStream paid to the IESO ($57.92 per kWh) over the 2013 to 2014 period. The shortfall of $1.08 per MWh between the average billed and the average cost applied to the 2013 and 2014 Global Adjustment consumption of 9,047,879 MWh resulted in the under recovery balance of $10.3 million.

**N-Energy Probe-50**

**REF: Ex. N, Tab 1, Schedule 1**

Please update Table 1 to reflect the reduction in the Board's prescribed interest rate effective April 1, 2015 to 1.10% and assume this rate is in place through to the end of 2015.

**RESPONSE:**

**See Table N-EP-50-1 below.**

**Table N-EP-50-1: Revised Table 1 using Updated 2015 Projected Interest ($000)**

| **Description** | **Filed Amount** | **Revised Amount [2]** |
|---|---|---|
| Group 1 and 2 excluding certain accounts[1] | $2,556.6 | $2,547.3 |
| Account 1589 Global Adjustment | $10,422.1 | $10,386.0 |
| Account 1575 IFRS PP&E Amount | ($2,392.7) | ($2,392.7) |
| Account 1568 LRAMVA | ($504.3) | ($505.2) |
| Account 1555 Stranded Meters residual | $599.1 | $597.6 |
| **Total for disposition** | **$10,680.8** | **$10,633.0** |

**Notes:**

1. Excluding accounts, 1555, 1568, 1575 and 15890

2. Revised total claim based on Board prescribed interest rate of 1.10% as of April 1,2015

**N-Energy Probe-51**

**REF: Ex. N, Tab 3**

Is PowerStream requesting the closure of any existing deferral or variance accounts? If yes, please provide details.

**RESPONSE:**

PowerStream notes that the following existing deferral or variance accounts are no longer active and, the residual balances have been included for disposition in this application. These accounts could be closed:

- 1508 Other Regulatory Assets, Sub-account IFRS Transition Costs Variance; and
- 1555 Smart Meter Capital and Recovery Offset Variance Account, Sub-accounts Stranded Meter Costs.

## N-VECC-40

## REF: Ex. N/T-1/S-1/pg. 1 & 4

a) Please provide the detailed calculations supporting the $505.3 k LRAMVA total to be returned to customers and the allocation to customer classes. Note: As part of the response please provide any OPA/IESO evaluation reports regarding the actual CDM achieved for the years concerned and indicate how the results set out in the reports were translated into actual billing determinants by customer class.

## RESPONSE:

a) Table N-VECC-40-1 below provides details of the PowerStream's current LRAMVA claim and Account 1568 balance as presented in 2016 EDVAR Continuity Schedule filed in Exhibit N of $504,257 credit to be returned to customers. It also includes a restatement of the imputed interest for 2015 to reflect the approved recoveries in 2015 and removal of the accounting estimate for 2014 resulting in an amount of $510,443 credit to be returned to customers.

**Table N-VECC-40-1: LRAMVA Claim Summary**

| | | | A | B | C = A - B | D | E = C + D | F | G = E - F |
|---|---|---|---|---|---|---|---|---|---|
| | Principal | Interest | Principal plus Interest Dec 31, 2014 | Board-Approved (2015 IRM) Disposition | Principal plus Interest Dec 31, 2014 less BA Amounts | 2015 Interest Adjustment | Adjusted Principal plus Interest | Proposed 2016 EDR Disposition (2011-2013 CDM) | Remaining Balance (2014 CDM) |
| **2011** | $193,081 | $11,194 | $204,275 | $202,815 | **$1,460** | **$1** | **$1,461** | **$1,461** | $0 |
| **2012** | $601,101 | $15,197 | $616,298 | $598,866 | **$17,433** | **$340** | **$17,773** | **$17,773** | $0 |
| **2013** | ($512,064) | ($6,014) | ($518,078) | | **($518,078)** | **($11,598)** | **($529,677)** | **($529,677)** | $0 |
| **2014** | ($5,173) | $101 | ($5,071) | | ($5,071) | ($76) | **($5,147)** | | ($5,147) |
| **Total** | **$276,945** | **$20,479** | **$297,423** | **$801,680** | **($504,257)** | **($11,333)** | **($515,590)** | **($510,443)** | **($5,147)** |

The final balance in the 2016 EDVAR Continuity Schedule includes 2014 balances related to 2014 CDM activities (Column AJ - Transactions Debit / (Credit) during 2014 excluding interest and adjustments) activity. PowerStream will not be submitting an application to recover LRAMVA amount related to 2014 CDM activities as part of this application. The 2014 savings are based on internal estimates from program results reported to the OPA. The OPA CDM report for 2014 is expected to be issued in September 2015. Given the uncertainty regarding the final amount for 2014 at the time of this application, PowerStream proposes to update the program results as based on the 2014 OPA CDM report and provide the resulting LRAMVA balances as a part of an annual adjustment mechanism, if these balances are deemed significant.

PowerStream confirms that it has relied on the most recent and appropriate final CDM evaluation report from the Ontario Power Authority ("OPA") attached as an Appendix 1 - OPA Annual CDM Report 2013 - Final Verified Results ("OPA CDM Report") and is in compliance with the OEB CDM Guidelines (EB-2012-003).

In accordance with the OEB's Filing Requirements for Electricity Distribution Rate Applications (July 17, 2013), PowerStream is requesting to clear the balance in the LRAMVA variance account 1568, as of December 31, 2013, plus interest improvement on the principal balance to December 31, 2015. PowerStream's total amount requested for disposition is a credit of $510,443, representing a principal balance credit of $488,849, as at the end of 2013, and carrying charges as a credit of $21,594 for 2011 through 2015. These balances relate to Conservation and Demand Management ("CDM") activities in 2013, as well as the true-up for CDM activities incurred in 2011-2012. A negative balance indicates that the actual CDM savings exceeded the projected CDM savings. PowerStream proposes to dispose of the total of $510,443 through class-specific volumetric rate riders, over a period of twelve months, from January 1, 2016 to December 31, 2016.

Table N-VECC-40-2 below provides the breakdown of the current claim of $510,443.

**Table N-VECC-40-2: LRAMVA Amounts as at December 31, 2013**

| Rate Classification | LRAMVA 2011 | LRAMVA 2012 | LRAMVA 2013 | Carrying Charges | Total Claim |
|---|---|---|---|---|---|
| LRAM/VA - Residential | $17 | $2,512 | ($369,794) | ($15,594) | ($382,859) |
| LRAM/VA - GS<50 | $0 | $14,182 | $40,121 | $1,692 | $55,995 |
| LRAM/VA - GS>50 | $67 | $6,437 | ($155,278) | ($6,548) | ($155,322) |
| LRAM/VA - LU | $0 | $0 | ($5,144) | ($217) | ($5,361) |
| LRAM/VA - USL | $0 | $0 | ($3,234) | ($136) | ($3,370) |
| LRAM/VA - Sentinel | $0 | $0 | ($157) | ($7) | ($163) |
| LRAM/VA - S/L | $0 | $0 | ($18,579) | ($783) | ($19,363) |
| **Total** | **$84** | **$23,131** | **($512,064)** | **($21,594)** | **($510,443)** |

Table N-VECC-40-3 summarizes the LRAMVA by rate class and calculates the rate riders using the most-recent 12-month actual billing determinants. The 2016 Proposed billing determinants have been used to calculate the rate riders.

### Table N-VECC-40-3: LRAMVA Rate Riders

| Rate Class | Total Claim | Billing Type | Billing Units (2016 Proposed) | Rate Rider |
|---|---|---|---|---|
| Residential | ($382,859) | kWh | 2,750,618,680 | **($0.0001)** |
| GS<50 | $55,995 | kWh | 1,040,222,607 | **$0.0001** |
| GS>50 | ($155,322) | kW | 12,212,781 | **($0.0127)** |
| LU | ($5,361) | kW | 150,807 | **($0.0355)** |
| USL | ($3,370) | kWh | 14,169,725 | **($0.0002)** |
| Sentinel | ($163) | kW | 975 | **($0.1675)** |
| S/L | ($19,363) | kW | 148,205 | **($0.1306)** |
| | **($510,443)** | | | |

The 2011-2012 actual amounts, as filed in 2015 IRM Application (EB-2014-0108), are adjusted based on the 2013 OPA CDM Report for 2011-2012 savings. The 2013 amount represents actual savings based on the OPA CDM report.

Table N-VECC-40-4 below demonstrates the details of 2011-2012 adjustment by comparing LRAMVA claim as submitted in 2015 IRM (EB-2014-0108) and updated amounts calculated as based on the OPA CDM Report.

### Table N-VECC-40-4: 2015 IRM LRAMVA Claim Adjustment Details

| Rate Class | LRAMVA 2011 Amount | LRAMVA 2012 Amount | LRAMVA 2011 Amount | LRAMVA 2012 Amount | 2011 Adjustment | 2012 Adjustment |
|---|---|---|---|---|---|---|
| | 2015 IRM (EB-2014-0108) | | As Updated on 2013 OPA CDM Report | | Current Claim | |
| LRAM/VA - Residential | $58,877 | $152,578 | $58,894 | $155,090 | $17 | $2,512 |
| LRAM/VA - GS<50 | 74,637 | 325,584 | $74,637 | $339,765 | $0 | $14,182 |
| LRAM/VA - GS>50 | 59,483 | 99,808 | $59,550 | $106,245 | $67 | $6,437 |
| **Sub-Total by Year** | **$192,997** | **$577,970** | **$193,081** | **$601,101** | **$84** | **$23,131** |
| **Total by Group - Principal** | | **$770,967** | | **$794,182** | | **$23,215** |

2011 and 2012 rates did not contain any reduction for CDM programs in a 4-year period January 1, 2011 to December 31, 2014; consequently, the entire amount of the OPA reported savings represents the variance between CDM in rates and actual CDM results. PowerStream's 2013 rates contain a reduction for the level of CDM savings. The difference between the levels of CDM program activities included in the load forecast and the actual impacts of authorized CDM activities achieved in PowerStream service area are the volumetric variance used to determine the 2013 LRAMVA amounts.

PowerStream has provided its LRAMVA calculations by year for each rate class in Table N-VECC-40-5 through N-VECC-40-7 below. The LRAMVA principal amounts for each year were determined by applying, within each customer class, PowerStream's historic Board-Approved variable distribution charge in place applicable to that class to the volumetric variance (positive or negative).

### Table N-VECC-40-5: LRAMVA for 2011

| Rate Class | 2011 Approved CDM Savings incl. in Load Forecast [1] | 2011 Actual Achieved CDM Savings[2] | Variance | 2011 Board-Approved Distribution Rate | LRAMVA 2011 |
|---|---|---|---|---|---|
| | kWh/kW | kWh/kW | kWh/kW | $/kWh/kW | $ |
| | PowerStream South Rate Zone | | | | |
| Residential | | 1,165 | 1,165 | 0.0131 | $ 15 |
| GS<50 | | 0 | 0 | 0.0113 | $ - |
| GS>50 | | 20 | 20 | 3.4354 | $ 67 |
| **Total** | | **1,184** | **1,184** | | **$ 82** |
| | PowerStream Barrie Rate Zone | | | | |
| Residential | | 115 | 115 | 0.0132 | $ 2 |
| GS<50 | | 0 | 0 | 0.0160 | $ - |
| GS>50 | | 0 | 0 | 1.7793 | $ - |
| **Total** | | **115** | **115** | | **$ 2** |
| | 2011 PowerStream Combined | | | | |
| Residential | | 1,280 | 1,280 | | $ 17 |
| GS<50 | | 0 | 0 | | $ - |
| GS>50 | | 20 | 20 | | $ 67 |
| **Total** | | **1,300** | **1,300** | | **$ 84** |

### Table N-VECC-40-6: LRAMVA for 2012

| Rate Class | 2012 Approved CDM Savings incl. in Load Forecast [1] | 2012 Actual Achieved CDM Savings[2] | Variance | 2012 Board-Approved Distribution Rate | LRAMVA 2012 |
|---|---|---|---|---|---|
| | kWh/kW | kWh/kW | kWh/kW | $/kWh/kW | $ |
| | PowerStream South Rate Zone | | | | |
| Residential | | 77,412 | 77,412 | 0.0131 | $ 1,014 |
| GS<50 | | 653,873 | 653,873 | 0.0113 | $ 7,389 |
| GS>50 | | 1,722 | 1,722 | 3.4461 | $ 5,935 |
| **Total** | | **733,007** | **733,007** | | **$ 14,338** |
| | PowerStream Barrie Rate Zone | | | | |
| Residential | | 114,360 | 114,360 | 0.0131 | $ 1,498 |
| GS<50 | | 424,570 | 424,570 | 0.0160 | $ 6,793 |
| GS>50 | | 283 | 283 | 1.7738 | $ 502 |
| **Total** | | **539,213** | **539,213** | | **$ 8,793** |
| | 2012 PowerStream Combined | | | | |
| Residential | | 191,772 | 191,772 | | $ 2,512 |
| GS<50 | | 1,078,443 | 1,078,443 | | $ 14,182 |
| GS>50 | | 2,005 | 2,005 | | $ 6,437 |
| **Total** | | **1,272,220** | **1,272,220** | | **$ 23,131** |

## Table N-VECC-40-7: LRAMVA for 2013

| Rate Class | 2013 Approved CDM Savings incl. in Load Forecast [1] | 2013 Actual Achieved CDM Savings[2] | Variance | 2013 Board-Approved Distribution Rate | LRAMVA 2013 |
|---|---|---|---|---|---|
| | kWh/kW | kWh/kW | kWh/kW | $/kWh/kW | $ |
| | 2013 PowerStream | | | | |
| Residential | 44,207,932 | 17,017,210 | (27,190,722) | 0.0136 | $ (369,794) |
| GS<50 | 16,984,563 | 19,956,498 | 2,971,934 | 0.0135 | $ 40,121 |
| GS>50 | 195,431 | 147,502 | (47,930) | 3.2397 | $ (155,278) |
| LU | 3,732 | | (3,732) | 1.3784 | $ (5,144) |
| USL | 208,627 | | (208,627) | 0.0155 | $ (3,234) |
| Sentinel | 20 | | (20) | 7.8050 | $ (157) |
| S/L | 2,868 | | (2,868) | 6.4785 | $ (18,579) |
| **Total** | | | | | **$ (512,064)** |

Tables N-VECC-40-8 through N-VECC-40-10 below, Details by CDM Initiative, present all CDM initiatives under each of the customer classes and the corresponding energy and peak demand savings for each initiative that have contributed to PowerStream's LRAMVA claim for 2013, as well as the adjustment details for 2011-2012 period.

## Table N-VECC-40-8: Details by CDM Initiative, 2011

| CDM Initiative | 2011 Net Annual Savings[1] | Half-Year Rule | |
|---|---|---|---|
| | Residential Rate Classification | | |
| | kWh | kWh | |
| HVAC Rebates | 2,560 | **1,280** | |
| **Residential Total** | **2,560** | **1,280** | |
| | GS <50 & GS>50 Rate Classification | | GS>50 Share |
| | kW | Converted to Billable kW[3] | kW |
| Program Enabled Savings | 3 | 20 | **20** |
| **GS>50 Total** | **3** | **20** | **20** |

NOTES:
1 - OPA Final 2013 Report
2 - for pre-2011 programs a half-year rule does not apply; instead full savings are allocated.
3 - net annual peak demand savings are converted to billable demand savings at the ratio of 6.5 for all programs except 'DR'.
DR savings are converted at the ratio of 3 (June through August - 3 months impact).

# Table N-VECC-40-9: Details by CDM Initiative, 2012

| CDM Initiative | 2011 Persistence | 2012 Net Annual Savings | Half Year Rule for 2012 | 2011-2012 Total |
|---|---|---|---|---|
| | Residential Rate Classification | | | |
| | kWh | kWh | kWh | kWh |
| HVAC Rebates | 2,560 | 65,322 | 32,661 | **35,221** |
| Home Assistance Program (HAP | 0 | 313,102 | 156,551 | **156,551** |
| **Residential Total** | **2,560** | **378,424** | **189,212** | **191,772** |

| | GS <50 & GS>50 Rate Classification | | | | GS<50 Share |
|---|---|---|---|---|---|
| | kWh | kWh | kWh | kWh | kWh |
| ERIP: Retrofit Business | | 2,712,548 | 1,356,274 | 1,356,274 | **1,071,456** |
| Direct Installed Lighting | | 13,973 | 6,987 | 6,987 | **6,987** |
| **GS<50 Total** | **0** | **2,726,521** | **1,363,261** | **1,363,261** | **1,078,443** |

| | GS <50 & GS>50 Rate Classification | | | | | GS>50 Share |
|---|---|---|---|---|---|---|
| | kW | kW | 2011 kW Converted to Billable kW<br>Net kW Savings X 12 | 2012 kWConverted to Billable kW<br>Net kW Savings X 6.5 | 2011-2012<br>Total | kW |
| ERIP: Retrofit Business | 0 | 494 | 0 | 3,211 | 3,211 | **734** |
| Energy Audit | 0 | 5 | 0 | 33 | 33 | **33** |
| Program Enabled Savings | 3 | 185 | 36 | 1,203 | 1,239 | **1,239** |
| **GS>50 Total** | **3** | **684** | **36** | **4,446** | **4,482** | **2,005** |

NOTES:
1 - OPA Final 2013 Report
2 - for pre-2011 programs a half-year rule does not apply; instead full savings are allocated.
3 - net annual peak demand savings are converted to billable demand savings at the ratio of 6.5 for all programs except 'DR'.
DR savings are converted at the ratio of 3 (June through August - 3 months impact).

## Table N-VECC-40-10: Details by CDM Initiative, 2013

| CDM Initiative | 2011 Persistence at 95%[4] | 2012 Persistence | 2013 Net Annual Savings | Half Year Rule for 2013 | 2011-2013 Total | |
|---|---|---|---|---|---|---|
| | Residential Rate Classification | | | | | |
| | kWh | kWh | kWh | kWh | kWh | |
| Fridge Pick Up | 1,120,913 | 690,707 | 424,061 | 212,031 | **2,023,651** | |
| HVAC Rebates | 4,161,189 | 2,826,607 | 2,830,426 | 1,415,213 | **8,403,009** | |
| Coupons (and retailers events) | 3,238,771 | 1,870,675 | 1,652,111 | 826,056 | **5,935,502** | |
| Peaksaver | 3,077 | 28,587 | 16,249 | 8,125 | **39,789** | |
| Retailer Co-Op/Sears | 2,218 | 0 | 0 | 0 | **2,218** | |
| Residential New Construction | 2,314 | 0 | 0 | 0 | **2,314** | |
| Home Assistance Program (HAF | 0 | 313,102 | 595,251 | 297,626 | **610,728** | |
| **Residential Total** | **8,528,483** | **5,729,678** | **5,518,098** | **2,759,049** | **17,017,210** | |
| | GS <50 &Rate Classification | | | | | |
| | kWh | kWh | kWh | kWh | kWh | |
| ERIP: Retrofit | 1,735,151 | 2,996,624 | 1,338,621 | 669,310 | **5,401,085** | |
| Direct Installed Lighting | 5,036,168 | 5,438,316 | 7,944,313 | 3,972,157 | **14,446,641** | |
| ERIP: pre-2011[2] | 37,457 | 0 | 0 | 0 | **37,457** | |
| Multi-Family efficiency rebates: p | 50,083 | 0 | 0 | 0 | **50,083** | |
| Business Refrigeration | 0 | 0 | 42,465 | 21,232 | **21,232** | |
| **GS<50 Total** | **6,858,859** | **8,434,940** | **9,325,398** | **4,662,699** | **19,956,498** | |
| | GS>50 Rate Classification | | | | | |
| | kW | kW | kW | 2011-2012 Converted to Billable kW Net kW Savings X 12 | 2013 Converted to Billable kW Net kW Savings X 6.5 | 2011-2013 Total |
| ERIP: Retrofit | 1,693 | 4,648 | 4,744 | 76,094 | 30,838 | **106,932** |
| New Construction and Major Rer | 10 | 0 | 778 | 125 | 5,057 | **5,182** |
| Energy Audit | 5 | 57 | 79 | 744 | 514 | **1,258** |
| Energy Manager | 0 | 19 | 421 | 228 | 2,737 | **2,965** |
| Program Enabled Savings | 3 | 185 | 5 | 2,256 | 33 | **2,289** |
| Business Refrigeration | 0 | 0 | 2 | 0 | 10 | **10** |
| ERIP: pre-2011 | 115 | 0 | 0 | 1,375 | 0 | **1,375** |
| High Performance New Construc | 92 | 109 | 14 | 2,419 | 92 | **2,511** |
| DR3 | 3,877 | 4,418 | 8,327 | | 24,981 | **24,981** |
| **GS>50 Total** | **5,795** | **9,436** | **14,370** | **83,241** | **64,260** | **147,502** |

NOTES:
1 - OPA Final 2013 Report
2 - for pre-2011 programs a half-year rule does not apply; instead full savings are allocated.
3 - net annual peak demand savings are converted to billable demand savings at the ratio of 6.5 for all programs except 'DR'.
DR savings are converted at the ratio of 3 (June through August - 3 months impact).
4 - 2011 persistence is assumed at 95% (diminishes for the 2nd year)

Net annual peak demand kW savings are converted to billable demand kW savings at the ratio of 6.5. The conversion factor of 6.5 is based on load savings distribution as illustrated in Table N-VECC-40-11 below. Monthly savings of 504 kW for all programs (excluding DR3) are added each month, while June – August months include the addition of savings resulting from the DR3 program.

## Table N-VECC-40-11: Billed kWs Reduction

| Month Added | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Jan** | 504 | 504 | 504 | 504 | 504 | 504 | 504 | 504 | 504 | 504 | 504 | 504 | 6,043 |
| **Feb** | | 504 | 504 | 504 | 504 | 504 | 504 | 504 | 504 | 504 | 504 | 504 | 5,539 |
| **Mar** | | | 504 | 504 | 504 | 504 | 504 | 504 | 504 | 504 | 504 | 504 | 5,036 |
| **Apr** | | | | 504 | 504 | 504 | 504 | 504 | 504 | 504 | 504 | 504 | 4,532 |
| **May** | | | | | 504 | 504 | 504 | 504 | 504 | 504 | 504 | 504 | 4,029 |
| **Jun** | | | | | | 504 | 504 | 504 | 504 | 504 | 504 | 504 | 3,525 |
| **Jul** | | | | | | | 504 | 504 | 504 | 504 | 504 | 504 | 3,022 |
| **Aug** | | | | | | | | 504 | 504 | 504 | 504 | 504 | 2,518 |
| **Sep** | | | | | | | | | 504 | 504 | 504 | 504 | 2,014 |
| **Oct** | | | | | | | | | | 504 | 504 | 504 | 1,511 |
| **Nov** | | | | | | | | | | | 504 | 504 | 1,007 |
| **Dec** | | | | | | | | | | | | 504 | 504 |
| **Subtotal** | 504 | 1,007 | 1,511 | 2,014 | 2,518 | 3,022 | 3,525 | 4,029 | 4,532 | 5,036 | 5,539 | 6,043 | 39,280 |
| **DR3** | | | | | | 8,327 | 8,327 | 8,327 | | | | | 24,981 |
| **Total** | 504 | 1,007 | 1,511 | 2,014 | 2,518 | 11,349 | 11,852 | 12,356 | 4,532 | 5,036 | 5,539 | 6,043 | 64,261 |

| Programs | kW reduction | Billed kWs | Ratio |
|---|---|---|---|
| DR3 | 8,327 | 24,981 | 3.0 |
| Ongoing | 6,043 | 39,280 | 6.5 |
| Total | 14,370 | 64,261 | |

**N-VECC-41**

**REF: Ex. N/T-1/S-1/pg. 1 & 4**

a) What is the current status of the GS>50 TOU meter replacement program?
b) What are the expected balances for the proposed deferral account for each of the years 2015 through 2020?

**RESPONSE:**

a) Presently new GS>50 kW customers receive interval meters and are connected to the MV90 system. There is insufficient capacity in PowerStream's MV90 system to accommodate all GS>50 kW customers. PowerStream is putting into place a solution that would allow it to replace the meters of existing customers with new TOU demand meters that can be read without requiring a phone line and the MV90 system. These TOU demand meters will replace meters for existing GS>50 kW demand customers as well as new customers going forward.

b) The forecasted balance in the proposed deferral account represents the net book value of stranded meters that are being replaced. Unexpected incremental costs that are not in the capital investments proposed in this filing will be also be added to the deferral account. See Table N-VECC-41-1 below.

**Table N-VECC-41-1: Stranded Demand Meter Deferral Account Estimated Amounts**

| **Deferral Account** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
|---|---|---|---|---|---|---|
| Opening NBV | **$ -** | $ 330,300 | $ 918,234 | $ 1,506,168 | $ 2,094,102 | $ 2,682,036 |
| Additions to NBV | $ 330,300 | $ 587,934 | $ 587,934 | $ 587,934 | $ 587,934 | $ 587,934 |
| **Closing NBV** | **$ 330,300** | **$ 918,234** | **$ 1,506,168** | **$ 2,094,102** | **$ 2,682,036** | **$ 3,269,970** |

| **NBV of Replaced meters** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **Total** |
|---|---|---|---|---|---|---|---|
| # of units replaced | 450 | 801 | 801 | 801 | 801 | 801 | 4,455 |
| Cost per unit | $1,468 | $1,468 | $1,468 | $1,468 | $1,468 | $1,468 | 8,808 |
| Estimated Cost | $ 660,600 | $ 1,175,868 | $ 1,175,868 | $ 1,175,868 | $ 1,175,868 | $ 1,175,868 | $ 6,539,940 |
| Accumulated deprecation | $ 330,300 | $ 587,934 | $ 587,934 | $ 587,934 | $ 587,934 | $ 587,934 | $ 3,269,970 |
| **Net Book Value (NBV)** | | | | **$ 330,300** | **$ 587,934** | **$ 587,934** | **$ 3,269,970** |

**N-VECC-42**

**REF: All**

a) How does PowerStream propose to address the proposed Board changes to the Distribution System Code affecting billing frequency?

**RESPONSE:**

a) Please see the responses to G-Energy Probe-17.

**<u>AMPCO-31</u>**

**Ref: General, Data Analytics**

<u>Preamble:</u> AMPCO seeks to understand the data that PowerStream collects and the information that is available to better understand the patterns and trends in service quality to customers specifically related to power quality, voltage sags, power blips, harmonics, etc.

a) Please provide an overview of PowerStream's current grid control structure.

b) Please provide any schematics, technical drawings, technical manuals or other documents related to the grid control centre and how it functions.

c) Please provide an overview of what PowerStream monitors that is within PowerStream's control related to power quality and system performance.

d) Please discuss the data vectors and the telemetry that is available.

e) Please explain the totality of the data that is collected and how it is used.

f) Please discuss how customers are notified of potential power quality issues.

**RESPONSE:**

a) PowerStream's System Control Centre is a twenty four hour, seven days per week operation. System Controllers monitor and control the distribution system remotely via the Supervisory Control and Data Acquisition (SCADA) system. The SCADA monitors all of PowerStream's eleven transformer stations as required by both the Transmission System Code and Independent Electricity System Operator ("IESO"). There are also fifty-four municipal substations on PowerStream's distribution system grid that are monitored and controlled via SCADA, as well as over 600 remotely controlled switches deployed strategically through the distribution network.

System Controllers monitor the distribution network, ensuring voltage levels and system loading is maintained within system limits. On a daily basis, switching (redirection of electrical current) is carried out on the system for different purposes which include load management, circuit isolation for construction and general maintenance purposes, as well as power restoration. System Control directs all system switching operations, issues all work protection required to isolate plant and manages PowerStream's power restoration activities.

The Outage Management System (OMS) compiles information from smart meters and customer calls into the Outage Interactive Voice Response (IVR) phone system to pin point outage locations so that crews can be more effectively dispatched to a site to restore power. Strategically located remote line sensors communicate back to the SCADA system to provide accurate outage location and telemetry information. System Controllers and Call Centre Customer Service Agents are able to interrogate or “ping” a customer’s smart meter to determine if the customer’s problem is internal or external to the home prior to dispatching a trouble crew to investigate a power problem.

b) PowerStream is unable to provide these due to security implications.

c) The System Control Centre makes use of the following technologies:

- Survalent SCADA system which monitors and alarms on changes from the normal operating parameters on the distribution system. These include but are not limited to Voltage, Current, True and Apparent power, Frequency, Fault levels, Fault indication, etc.;
- Horstman remote line sensors with power quality monitoring;
- Grid Sentry remote line sensors with power quality monitoring;
- Pad-mounted and aerial remote controllable devices with power quality monitoring;
- Three types of automated restoration schemes;
- Access to the smart meters on the distribution system to check power quality at the service entrance on demand;
- ESRI GIS system for modelling the distribution network;
- Responder OMS for keeping record of customer issues reported to the Control Centre;
- Power quality recorders installed at the customer premise on request;
- Customer Information System (CIS) for transformer loading inquiry – for overload conditions.
- CYME software for determining fault location; and
- PI software for reporting events

d) Telemetry available includes:

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- Current, voltage, power, power factor and frequency at the Station level;
- Current, voltage and power on the distribution system;
- Sensors for monitoring the health of critical equipment on the distribution system (thermal, pressure and oil and gas levels etc.);
- Sensors for monitoring faults and power quality on the distribution system; and
- Sequence of events monitoring at transformer stations.

e) Event data, fault data and telemetered data is collected and stored on the SCADA system and OMS system. The data is used for monitoring, analysis and reporting on elements of the distribution system.

f) PowerStream monitors the distribution system to ensure adequate voltage is supplied.  PowerStream relies on the customer to notify of any power quality issues at their service entrance.