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# Section I

**I-Staff-1**

**Ref: S I-1/T1/S1/p. 1 and S VI/S1/p. 2**

At the first reference, it is stated that:

> On April 16, 2015, the potential of a four-party merger involving PowerStream, Enersource, Horizon Utilities and Hydro One Brampton was announced. The parties have signed a non-binding Letter of Intent to explore the potential benefits of a merger. There is also an option for three of the parties to purchase Hydro One Brampton at a pre-defined price.
>
> Currently the parties are in the process of assessing the financial merits of the merger. Transaction costs (before the merger) and transition costs (after the merger) are being weighed against the potential "synergy savings" from bringing four distributors together. If the Shareholders approve the merger (with or without the purchase of Hydro One Brampton) then OEB approval will be sought through a MAADs application.
>
> This Custom IR rate application is for PowerStream as a "standalone" distributor. It is PowerStream's intention to proceed with the Application on this basis regardless of whether or not a decision to merge is made and a MAADs application submitted.

At the second reference, it is stated that the proposed rate plan would terminate under the following conditions:

> PowerStream is proposing to apply the Board's existing policy in relation to off-ramps. Under the RRFE, the Board expects that distributors that apply using the custom rate-setting method will be committed to that method for the duration of the approved term. The Board recognized that a distributor may need to seek early termination and had provided a mechanism for regulatory review to be initiated if the distributor performs outside of the ±300 basis points earnings dead band or if its performance erodes to unacceptable levels.

a) Please confirm that no impacts of the proposed merger are reflected in the application, or if this is not the case, please explain what these impacts are.

b) Please provide an update as to the current status of the merger including the anticipated process for completion and the timing of future milestones to completion.

c) Please confirm that the means of acquiring Hydro One Brampton will have no impact on customer rates during the rate plan period, or if this is not confirmed, please explain.

d) Please state whether or not the potential merger could result in termination of the rate plan. If so, please discuss the circumstances under which this could occur.

**RESPONSE:**

a) Confirmed.

b) Negotiations are continuing and if they reach a successful conclusion, the transaction will be brought to the respective Boards and Shareholders for approval. Although subject to change, Shareholder deliberations are scheduled to be complete by September 30, 2015.

c) Confirmed.

d) PowerStream is guided by the *Report of the Board: Rate-Making Associated with Distributor Consolidation, March 26, 2015, Board File No. EB-2014-0138*. PowerStream's understanding of this report is that following a merger, any Custom IR plan would continue to its normal termination date. In PowerStream's case, that would be December 31, 2020.

**I-Staff-2**

**Ref: S I/T1/S1**

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

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

**RESPONSE:**

PowerStream became aware of a letter of comment dated July 7, 2015 regarding its rate application that was sent directly and only to the Board. The letter was placed on the public record on July 15, 2015. On July 31, 2015 PowerStream filed a response to this letter of comment.

PowerStream will continue to monitor the public record for any further letters of comment and respond accordingly.

**I-Staff-3**

**Ref: S I/T3/S1/p. 4**

Table 4 of the above reference shows total load and customers for the period 2013 to 2020.

OEB staff notes that in the period from 2014 to the 2020 Test year weather normalized load decreases by roughly 1%, while total customers increases by roughly 11%.

Please explain why in spite of a total customer increase of 11% in the 2014 to 2020 period, total load is decreasing by 1% in the same period.

**RESPONSE:**

Table 1 shows the annual increase/decrease in total customers and load as referenced in S I/T3/S1/p.4. Table 2 shows weather normalized historical actual and forecasted load.

While annual customer growth has been averaged approximately 2%, the average customer usage has been declining as discussed in Section VI, Tab 13, Schedule 1. Declining customer usage has been occurring and is largely driven by energy efficiency improvements, in addition to the OPA/IESO funded CDM activity.

This decline in customer usage is projected to continue through the forecast period with continued improvements in energy efficiency. Energy efficiency improvements are the result of naturally occurring replacement of less efficient appliances, new appliance and lighting efficiency standards, and improving housing shell efficiency. Continued structural changes that include increasing share of less energy-intensive businesses and changing housing mix (with multi-family units gaining market share) also contribute to declining customer usage.

**Table 1: Annual Increase/Decrease on Customers & Load**

| Unit | 2013 Board Approved | 2013 Actual (WN) | 2014 Actual (WN) | 2015 Bridge Year | 2016 Test Year | 2017 Test Year | 2018 Test Year | 2019 Test Year | 2020 Test Year | |
|---|---|---|---|---|---|---|---|---|---|---|
| kWh | 8,480,948,224 | 8,506,508,080 | 8,498,446,891 | 8,493,223,520 | 8,509,011,422 | 8,485,564,197 | 8,462,668,700 | 8,434,654,514 | 8,411,546,941 | |
| Customers | 350,482 | 349,797 | 356,461 | 362,543 | 368,663 | 374,990 | 381,372 | 387,845 | 394,508 | |
| % Change | | | | | | | | | | 2014-2020 |
| kWh | | | -0.09% | -0.06% | 0.19% | -0.28% | -0.27% | -0.33% | -0.27% | -1.02% |
| Customers | | | 1.91% | 1.71% | 1.69% | 1.72% | 1.70% | 1.70% | 1.72% | 10.67% |

## Table 2: Weather Normalized Historical and Forecast Load

| Years | Weather Normalized Actual/Forecast Before CDM Adjustment (GWh) | % Change | CDM Adjustment (GWh) | Weather Normalized Actual/Forecast After CDM Adjustment (GWh) | % Change |
|---|---|---|---|---|---|
| 2008 | 8,552 | | | 8,552 | |
| 2009 | 8,205 | -4.05% | - | 8,205 | -4.05% |
| 2010 | 8,225 | 0.23% | - | 8,225 | 0.23% |
| 2011 | 8,339 | 1.39% | - | 8,339 | 1.39% |
| 2012 | 8,476 | 1.65% | - | 8,476 | 1.65% |
| 2013 | 8,507 | 0.36% | - | 8,507 | 0.36% |
| 2014 | 8,498 | -0.09% | - | 8,498 | -0.09% |
| **Average** | | **-0.09%** | | | |
| **2015 Bridge Year** | 8,519 | 0.24% | 26.04 | 8,493 | -0.06% |
| **2016 Test Year** | 8,594 | 0.87% | 84.68 | 8,509 | 0.19% |
| **2017 Test Year** | 8,643 | 0.58% | 157.71 | 8,486 | -0.28% |
| **2018 Test Year** | 8,711 | 0.78% | 248.13 | 8,463 | -0.27% |
| **2019 Test Year** | 8,791 | 0.92% | 356.24 | 8,435 | -0.33% |
| **2020 Test Year** | 8,876 | 0.97% | 464.53 | 8,412 | -0.27% |
| **Average** | | **0.73%** | | | **-0.17%** |

**I-Staff-4**

**Ref: SI/T3/S1/p. 7, PowerStream Inc. *Settlement Agreement Filed: October 24, 2012,* p.13 and SVI/T31/S1/p. 7**

In Table 9 of the first reference, PowerStream states that actual 2013 capital spending was $93.7 million.

In the second reference, a 2013 Test year capital spending level of $114.3 million is accepted for purposes of settlement, which is 22% greater than the 2013 actual level.

In the third reference, a 2014 actual capital spending level of $109.5 million is shown. The proposed capital spending level for the 2016 test year from the first reference is $132.9 million which is 21% higher than the 2014 actual level.

a) Please provide an explanation for the difference between the 2013 Test year approved capital spending level and the 2013 actual.

b) Please explain why the OEB should have confidence that the 2016 proposed capital spending level will be achieved given the 2013 differential noted in a).

c) Please state how PowerStream's 2015 actual capital spending to date is tracking against forecasts.

d) Please state whether or not PowerStream took into account the cumulative impact that its capital spending since 2012 would have on 2016 rates and, if so, what changes ensued from these considerations.

**RESPONSE:**

a) While $114,279,000 was the stated 2013 Test Year Approved capital spending level as shown in 2.3 of the October 24, 2012 Settlement Agreement, the true amount was approximately $112.2M due to a contributed capital increase of $2M as stated in 2.1 of the Settlement Agreement.

"For the purpose of settlement, the Parties agree that the net fixed asset portion of rate base should be adjusted to reflect a $2,000,000 increase in contributed capital in each of 2012 and 2013, and the Parties further agree that the working capital allowance should be adjusted to reflect the change in the OM&A budget."

The 2013 actual capital spending totaled $93.7M. The $18.5M difference between the approved spending and the actual spending was largely due to a significant amount of costs for PowerStream's CIS Replacement Project delayed until 2014, and also less spending in New Services and Road Authority Projects than anticipated.

b) PowerStream submits that the 2016 proposed capital spending level of $132.9M is reasonable, and will be achieved, as it is the direct result of prioritized initiatives necessary to maintain the distribution system in a good state of repair, and to maintain the effective operation of the company as a whole. The causes of the 2013 variance are unlikely to be repeated in 2016. A better indicator of PowerStream's ability to achieve its 2016 proposed capital spending level would be year 2014 where PowerStream's actual capital spending totaled $109.5M on a budget of $108.2M.

c) PowerStream's 2015 actual spending to date (YTD ending June 30) is $45.107M. The 2015 year end capital spending is presently forecasted to be on budget.

d) PowerStream recognizes that the rate structure under IRM creates a "catch up" on rates in the first year of re-basing. PowerStream's capital budgeting process considers many factors such as system reliability, the need to meet mandated requirements, safety, value to customers and the ability to finance the proposed capital spending. In approving the capital budget, the executive and the Board of Directors balance the need for the capital spending with the desire to keep rates competitive. As a result, the actual capital budget approved is reduced from the requested. The impact on the catch-up amounts is not factored into the selection of the capital portfolio, but is considered as part of the entire submission.

**I-Staff-5**

**Ref: SI/T3/S1/p. 13**

At the above reference, PowerStream discusses its Deferral and Variance Accounts.

Chapter 2 of the Filing Requirements notes that “distributors must establish separate rate riders to recover the balances in the RSVAs from Market Participants (“MPs”) who must not be allocated the RSVA account balances related to charges for which the MPs settle directly with the IESO (e.g. wholesale energy, wholesale market services).”

Chapter 2 of the Filing Requirements also note that “distributors who serve Class A customers per O.Reg 429/04 (i.e. customers greater than 5 MW) must propose an appropriate allocation for the recovery of the global adjustment variance balance based on their settlement process with the IESO.

a) Please state whether or not PowerStream serves any consumers that are Wholesale Market Participants (“WMPs”).

   If yes:
   i. Have these consumers been WMPs throughout the entire time over which variances accumulated in the RSVA accounts are proposed for disposition?
   ii. Please confirm that RSVA account balances have not been allocated to WMP customers as they settle these charges directly with the IESO.

b) Please state whether or not PowerStream serves any class A consumers that settle energy charges directly with PowerStream. If yes, please explain how balances in Account 1589 (Global Adjustment) have been allocated to these consumers.
c) As of July 1, 2015, per O.Reg 429/04, an eligible customer with a maximum hourly demand over three megawatts, but less than five can elect to become a Class A for an applicable adjustment period of one year.

   i. Please state whether PowerStream serves any of these customers

   ii. Please discuss PowerStream’s approach to this matter in the context of Section 2.9.7.1 Global Adjustment which is a new section in Chapter 2 of the OEB’s Filing Requirements issued July 16, 2015.

**RESPONSE:**

a) PowerStream serves one customer that became a Wholesale Market Participant ("WMP") in November 2012.

   i. Yes. This customer has been a WMP throughout the entire time – 2013 and 2014, over which period, variances accumulated in the RSVA accounts are proposed for disposition.

   ii. PowerStream's billing practice is not to charge any Deferral and Variance rate riders to WMP customers. However, the billing determinant quantity for this WMP customer has been included in the calculation of rate riders regarding to the proposed RSVA balance disposition.

b) Yes. PowerStream serves Class A customers that settle energy charges directly with PowerStream.

   The Global Adjustment is charged to these Class A customers on a monthly basis, at the actual cost paid by PowerStream to the IESO. On a month-to-month basis, using accrual accounting, there may be some variances in account 1589 due to cost estimation. On an annual basis, however, as all monthly estimation is reversed in the following month and replaced by the actual cost charged by the IESO, there is no variance in the account 1589 related to the Class A customers. Consequently, no variance from this account has been allocated to the Class A customers.

c) As of July 1, 2015, PowerStream had nine newly eligible Class A customers, in addition to its existing four Class A customers served in 2014.

   These newly eligible Class A customers, who participated in the Industrial Conservation Initiative, have a maximum hourly demand over 3 but less than 5 megawatts over the base period defined by the IESO (May 1/2014 – April 30/2015).

   These Class A customers pay Global Adjustment based on their percentage contribution to the top five peak Ontario demand hours (peak demand factor) over a year-long period. Please refer to I-Staff-5 – Appendix A for PowerStream's Peak Demand Factor July 1, 2015 – June 30, 2016.

   With regards to the recovery of the Global Adjustment, since the proposed Global Adjustment variance disposition is up to 2014, these new Class A customers will continue to be allocated and charged on the Global Adjustment rate rider. Starting July 1, 2015, there will not be any Global Adjustment variance balance allocated to these customers, as PowerStream will settle the Global Adjustment costs with these customers on the basis of actual costs.

**I-Staff-6**

**Ref: SI/T3/S1/p. 13**

At the above reference, PowerStream discusses its Deferral and Variance Accounts.

The OEB issued APH guidance on deferral accounts related to Renewable Generation Connection and Smart Grid Development accounts on March 31, 2015.

a) Please state whether or not PowerStream has followed this guidance (Guideline Q&A #8) as it applies to the portion for rate base inclusion.
b) If PowerStream has not followed this guidance, please make any required changes and re-file the information. If PowerStream does not wish to do this, please explain why not.

**RESPONSE:**

a) PowerStream has followed the APH guidance dated March 31, 2015, Q&A #8.

PowerStream has provided models that calculate the Renewable Generation Connection Rate Protection (RGCRP) amounts. These are based on the same model that has been approved in PowerStream's 2013, 2014 and 2015 distribution rate applications.

PowerStream has included only the direct benefit portion of the Renewable Generation Connection investments in rate base on an in-service basis. The cost of assets that is funded by RGCRP has been removed from rate base.

PowerStream has not recorded the capital and other costs approved in earlier years for funding by RGCRP to the accounts specified in Q&A#8 as this was not available at the time the entries were made. PowerStream will address this before the annual RRR filing for 2015.The RGCRP funded capital amounts however have been excluded from rate base as shown on Chapter 2 Appendix 2-BA, Fixed Asset Continuity Schedule, on the line titled "Less Socialized Renewable Energy Generation Investments".

PowerStream has included planned capital investment in Renewal Generation Connection and Smart Grid for 2015 to 2020 in rate base less any portion funded by RGCRP.

b) Please see the response to part (a) above. PowerStream has followed the Board's guidance. No changes are required.

**I-Staff-7**

**Ref: SI/T3/S1/p. 13**

At the above reference, PowerStream discusses its Deferral and Variance Accounts.

In calculating Deferral and Variance Account rate riders for sub-groups of customers within a class (e.g. WMPs and non-WMPs), distributors have used two approaches.

1) Rate riders grouped by the nature of the deferral and variance accounts (i.e. one set of rate riders for accounts related to transmission (e.g. 1584 and 1586) and another set of rate riders for accounts related to power (e.g. 1580 and 1588). For an example, see the EnWin Utilities Ltd. Final 2014 Tariff of Rates and Charges (EB-2014-0156).

2) Sets of rate riders calculated on the basis of the customer group to which they would apply (i.e. one rate rider for WMPs and one rate rider for non-WMPs). For an example, see Bluewater Power Distribution Corp.'s 2014 IRM application (EB-2013-0112).

Please state which approach PowerStream uses and explain why this is the case.

**RESPONSE:**

Due to the timing of the filing of this application, PowerStream used 2015 Deferral/Variance Account Workform (version 2.3), which doesn't follow either of the two approaches referred to above.

**I-AMPCO-1**

**Ref: Section I, Tab 1, Schedule 1**

a) Please identify the material cost categories in the application that could potentially be affected a merger and explain the impact.

b) Please discuss the impact on PowerStream's proposed performance metrics if a merger occurs.

**RESPONSE:**

a) If a merger were to occur, the new entity would seek to reduce the overall Operating, Maintenance & Administration costs. The cost categories affected would be mainly payroll and external contracted costs including consulting. The "General Plant" category of the capital budget could also be affected.

b) It is anticipated that PowerStream's proposed performance metrics would continue until such time that the new organization started to harmonize performance metrics.

**I-AMPCO-2**

**Ref: Presentation July 28, 2015, Slide 13**

Preamble: PowerStream references its “Journey to Excellence” based on the Excellence Canada framework.

a) Please explain why PowerStream chose the Excellence Canada framework over other frameworks.

b) Please provide the Business Case for the Journey to Excellence initiative.

c) Please provide the costs by year from the date the program commenced to the end of 2014 and the forecast costs for each of the years 2015 to 2020.

d) Please discuss how a merger could impact this initiative.

**RESPONSE:**

a) The Excellence, Innovation and Wellness Standard from Excellence Canada is a proven comprehensive Canadian framework and methodology that compares favourably with other national awards programs including the Malcolm Baldrige Award (U.S.), Deming Award (Japan and Australia), and the European Quality Award. The framework has demonstrated sustainable improvements from across many sectors in Canada. The Excellence Canada Progressive Excellence Program (PEP) provides guidance on continuous improvement, innovation, health and safety, culture and engagement, sustainability, and leadership, while continuing to be economically, socially and environmentally responsible and customer focused. These have been and continue to be drivers of PowerStream’s business, and the Excellence Canada framework has helped PowerStream become more proactive in its approach and practices.

b) There was no formal business case completed.

c) The Excellence Canada annual membership fee is $25,000.

d) At some time following the merger, the new organization would need to decide if it would adopt the Excellence Canada framework, an alternate framework or not use a third-party structure.

**I-AMPCO-3**

**Ref: Presentation July 28, 2015, Slide 20**

Preamble: PowerStream indicates it has already cut $50 million from the current capital plan with the majority of the cuts through deferrals.

Please provide the cuts in dollars allocated to System Access, System Renewal, System Service and General Plant and identify the programs impacted by cuts.

**RESPONSE:**

Refer to Table AMPCO-3 below to see the deferrals, cuts and adjustments, by year, by OEB category and sub-category/programs, from the original ask. The grand total of the deferrals, cuts, and adjustments totals over the 2015-2020 timeframe totals $58 million.

# Table AMPCO-3

| Major Category | Sub-Category / Program | Variance (2015) | Variance (2016) | Variance (2017) | Variance (2018) | Variance (2019) | Variance (2020) |
|---|---|---|---|---|---|---|---|
| General Plant | Buildings | $ 3,085,263 | -$ 196,687 | -$ 359,202 | -$ 41,802 | $ 18,995 | $ 268,993 |
| | CIS | -$ 1,400,000 | $ - | $ - | $ - | $ - | $ - |
| | Fleet | -$ 739,800 | $ - | -$ 48,150 | -$ 401,250 | $ - | $ - |
| | Information/Communication Systems | -$ 2,510,625 | -$ 3,598,311 | -$ 1,130,254 | -$ 2,354,618 | -$ 2,758,182 | $ 2,062,888 |
| | Tools | -$ 96,551 | -$ 266,682 | -$ 301,294 | $ 87,245 | -$ 110 | -$ 6,561 |
| | WFM | -$ 96,300 | -$ 321,000 | $ 321,000 | $ - | $ - | $ - |
| General Plant Total | | -$ 1,758,013 | -$ 4,382,680 | -$ 1,517,900 | -$ 2,710,425 | -$ 2,739,297 | $ 2,325,320 |
| | | | | | | | |
| System Access | Metering | -$ 654,741 | -$ 832,527 | -$ 1,379,864 | -$ 615,474 | -$ 1,191,871 | -$ 888,216 |
| | Other | -$ 329,006 | $ - | $ - | $ - | $ - | $ - |
| | Road Authority | -$ 1,450,000 | $ - | $ - | $ - | $ - | $ - |
| System Access Total | | -$ 2,433,747 | -$ 832,527 | -$ 1,379,864 | -$ 615,474 | -$ 1,191,871 | -$ 888,216 |
| | | | | | | | |
| System Renewal | Distribution Transformers - replace | -$ 620,000 | $ 620,000 | $ - | $ - | $ - | $ - |
| | Emergency/Restoration | -$ 1,519,999 | -$ 1,519,999 | -$ 1,530,001 | -$ 1,519,999 | -$ 1,520,000 | -$ 1,619,999 |
| | Overhead -rebuild/replace | -$ 645,353 | -$ 181,900 | -$ 692,597 | $ 1,556,843 | $ 912,775 | $ 794,703 |
| | Rear Lot Conversion | $ 151,000 | $ 370,000 | $ 250,000 | $ 205,000 | $ 120,000 | $ 33,000 |
| | Spare Parts | -$ 366,795 | -$ 160,018 | $ 1,296 | $ 482 | $ 481 | $ 169,169 |
| | Stations Replacement Program/Project | $ - | -$ 309,832 | -$ 2,261,325 | -$ 656,175 | $ 516,022 | $ 900,345 |
| | Storm Hardening | $ - | -$ 2,575,000 | -$ 2,672,000 | -$ 3,375,000 | -$ 4,183,000 | -$ 4,098,000 |
| | Switchgear - replace | -$ 321,991 | -$ 65,434 | $ - | $ - | $ - | $ - |
| | Underground - rebuild/replace | -$ 1,994,986 | -$ 1,560,723 | -$ 388,658 | -$ 115,453 | $ 262,663 | $ 85,554 |
| | Voltage Conversion | -$ 231,500 | -$ 1,581,212 | $ 881,500 | $ - | $ 169,597 | $ - |
| System Renewal Total | | -$ 5,549,624 | -$ 6,964,118 | -$ 6,411,785 | -$ 3,904,303 | -$ 3,721,463 | -$ 3,735,229 |
| | | | | | | | |
| System Service | | | | | | | |
| | Distribution Automation | -$ 959,535 | -$ 500,000 | $ 468,235 | $ - | $ - | $ - |
| | Line Capacity | -$ 1,221,129 | -$ 1,824,734 | -$ 4,116,107 | $ 536,742 | $ 1,105,733 | $ 2,751,003 |
| | Overhead - line extension | -$ 1,610,992 | $ 1,496,942 | $ - | -$ 2,645,589 | $ 2,070,229 | $ - |
| | Scada & Scada Communications | -$ 361,390 | -$ 173,635 | -$ 194,543 | -$ 233,543 | -$ 200,559 | -$ 58,859 |
| | Station Capacity | -$ 881,743 | $ 952,067 | -$ 490,784 | -$ 1,216,641 | $ 1,698,914 | $ 182,428 |
| | Station Reliability | -$ 675,047 | -$ 1,572,654 | -$ 143,427 | -$ 54,699 | -$ 692,148 | $ 316,962 |
| | Station Safety | -$ 139,241 | -$ 172,380 | -$ 172,719 | -$ 173,058 | -$ 130,597 | -$ 130,936 |
| | Station Security | $ - | -$ 150,289 | -$ 99,147 | -$ 99,995 | $ 143,795 | $ 60,566 |
| System Service Total | | -$ 5,849,077 | -$ 1,944,684 | -$ 4,748,492 | -$ 3,886,783 | $ 3,995,366 | $ 3,121,164 |
| Grand Total | | -$ 15,590,461 | -$ 14,124,009 | -$ 14,058,041 | -$ 11,116,983 | -$ 3,657,264 | $ 823,039 |
| | | | | | | | |
| | | | | | Overall Grand Total | | -$ 57,723,719.8 |

**I-AMPCO-4**

**Ref: Presentation July 28, 2015, Slide** 21

Preamble: Slide 21 provides a comparison of population: Beyond End-of-Life (2014) compared to Future Projected End-of-Life (2020) and Replaced for 2015-2020.

Please reproduce the slide showing a comparison of population: End-of-Life (2010) compared to Beyond End-of-Life (2014) and Replaced for 2010-2014.

**RESPONSE:**

Refer to Table AMPCO -4 below.

**Table AMPCO-4**

| Asset | Population | Typical Useful Life (Years) | Population beyond End of Life at December 31, 2010 | Population beyond End of Life at December 31, 2014 | Population replaced from 2011 - 2014 |
|---|---|---|---|---|---|
| Municipal Station Power Transformers | 65 (1) | 40 | 8 | 18 | 0 |
| Transformer and Municipal Station Circuit Breakers | 399 | 40 | 29 | 41 | 26 |
| Municipal Station Primary Switches | 66 (2) | 50 | 3 | 4 | 0 |
| TS and MS Relays | N/A | 30 | N/A | 27 | N/A |
| Underground Cable | 7,836 km | 25 | 966 km | 2,746 km | 350 km (3) |
| Distribution Transformers | 43,535 | 40 | 327 | 777 | 207 |
| Switchgear Mini-Rupter and Automated Switches | 1,739 (4) | 30 | 27 (4) | 307 | 89 (4) |
| Wood Poles | 38,070 | 45 | 2,577 | 3,301 | 1,253 |

(1) - does not include spare transformers
(2) - includes out-of-service units
(3) - Cable length includes cable replacement and cable injection
(4) - Number only includes Switchgear. ACA condition for Mini-Rupter and Automated Switches was not available.

**I-AMPCO-5**

**Ref: EB-2012-0161 Board Decision dated December 21, 2012 (2013 COS Application)**

3.3 Is the proposed Test Year Forecast of other revenues appropriate? (C2)

*Complete Settlement*: In its Application, PowerStream has recorded the revenues and costs associated with providing joint services to Shareholders in non-utility accounts. This represents a net total of $782,000, consisting of $272,000 mark-up on the services provided (the amount by which revenues for these activities exceed costs), and $510,000 in late payment charges revenue related to water services. The Parties agree that this amount should be recorded as an offset to revenue requirement.

Please confirm PowerStream continues to record this as an offset to revenue requirement.

**RESPONSE:**

PowerStream confirms that the revenues and costs associated with joint services have been included in this Application with the result that the net amount representing the mark-up has been included as an offset to revenue requirement.

The late payment penalties, on the water portion of bills, have been included in other income in the Application as an offset to revenue requirement.

**I-CCC-1**

With respect to the potential merger between PowerStream, Hydro One Brampton, Horizon Utilities Corporation and Enersource Inc.:

1) Please provide all letters of intent, memoranda of understanding, or similar documents related to the potential merger;

2) For a merger effective January 1, 2016, please explain all of the steps required to enable such a merger. Have milestones been set? If so, please describe those milestones;

3) For a merger effective January 1, 2016, when would the MADDs application be filed with the Ontario Energy Board?

4) Please describe all of the areas that would experience "synergy savings" as a result of the merger. Please identify the areas that would not experience savings.

5) If PowerStream agrees that an earnings sharing mechanism ("ESM") is appropriate in order to share savings with its customers during the term of a plan, how would PowerStream envision an ESM working under a new merged entity? If, from PowerStream's perspective an ESM could not be implemented, what mechanism could be incorporated into the plan that would ensure customers would share in any achieved savings?

6) If the Board approves a revenue requirement as a result of this application, which assumes a stand-alone entity, please explain why PowerStream believes those rates would be appropriate under new merged entity. Why would this be fair to its customers?

7) Does PowerStream have any written policies regarding mergers and acquisitions? If so, please provide those policies.

**RESPONSE:**

1) Negotiations are continuing and if they reach a successful conclusion, the transaction will be brought to the respective Boards and Shareholders for approval. The appropriate merger documents would be provided in a MAADs application, should the Shareholders approve the proposed merger.

2) Please see the response to I-Staff-1-b for the current milestones related to Board and Shareholder approval. If the approvals are received on this schedule, a MAADs application would be filed with the Board. The current schedule anticipates closing the transaction on March 31, 2016.

3) Please see the response to I-CCC-1- 2.

4) Please see the response to I-AMPCO-1a.

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

6) PowerStream is guided by the Report of the Board: Rate-Making Associated with Distributor Consolidation, March 26, 2015, Board File No. EB-2014-0138 for rate setting following a merger. This report indicates that there is an earnings sharing mechanism for the second five years in the rebasing deferral period.

7) No.

**I-CCC-2**

**Ref: Ex. I/T1/S1/p. 5**

For each year of the plan please list the “extraordinary items”. Are all other expenditures considered by PowerStream to be “business as usual”?

**RESPONSE:**

The following table provides the extraordinary items.

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|
| Capital Expenditure (In-Service) | | | | | | | |
| Vaughan TS | $ 4,434,185 | | | $ 21,898,260 | | | |
| CIS | | $ 45,874,000 | | | | | |
| Storm Hardening | | $ 3,499,998 | $ 7,900,017 | $ 7,999,752 | $ 7,499,834 | $ 6,900,540 | $ 7,200,072 |
| Vegetation Management | | | | | | | |
| | | | | | | | |
| OM&A Expense | | | | | | | |
| Vaughan TS | | | | | | | |
| CIS | $ 1,349,000 | $ 2,659,000 | $ 2,537,000 | $ 2,379,000 | $ 2,197,000 | $ 2,198,000 | $ 2,200,000 |
| Storm Hardening | | | | | | | |
| Vegetation Management | $ 299,000 | $ 599,000 | $ 1,213,000 | $ 1,793,000 | $ 2,270,000 | $ 2,806,000 | $ 3,348,000 |

Please see the responses to II-1-Staff-9 and II-1-Staff-12.

**I-CCC-3**

**Ref: Ex. I-T3/S1/p. 7**

System Renewal costs are dramatically increasing from 2011-2020. These costs relate to assets that need to be replaced as they are at, or beyond their expected useful life. Please explain why the asset replacement program was not accelerated earlier. Has the process PowerStream uses to determine the timing of replacement changed significantly since 2011?

**RESPONSE:**

PowerStream was formed by the merger of several utilities. PowerStream's first asset management plan was initiated in 2007 for transformer station assets.

PowerStream commenced the creation of its asset management plan for the distribution system in 2010 and started to implement and increase its asset renewal from year 2010. The current level of investments for two major categories cables and poles reached a steady state in 2012. Over the years PowerStream has been developing asset condition assessment process and adding assets to the renewal program such as Mini-Rupter switch replacement, automated switch replacement and Station switchgear replacement.

Fundamentally, there has been no change to how PowerStream has selected timing for asset replacement. PowerStream has continued to improve its methods for acquiring data to determine optimal asset replacement candidates within in the ACA program.

**I-CCC-4**

**Ref: Ex. G/T2/pp.-14**

Coordinated planning with third parties includes the Ontario regional planning process. Please provide any updates to each of the four regional planning processes that PowerStream has been a part of. Please explain how these processes may impact PowerStream's capital planning/expenditure process during the term plan.

**RESPONSE:**

PowerStream participates in the following regional planning processes:

- York Region IRRP
- Regional Infrastructure Planning (RIP) for Metro Toronto Region
- GTA North West Sub-Region
- South Simcoe Study

York Region IRRP:

York Region IRRP has been completed in spring 2015 and the VTS4 has been identified in the study as near term need. The outcomes of the York Region regional plan has resulted in capital expenditure requirements by PowerStream for the construction of a new transformer station (VTS#4) and its associated feeder integration within this DS Plan timeframe, specifically in spending between 2015 and 2017 for the station and 2016 to 2019 for feeder integration.

Currently, recruitment for membership on the local advisory council (LAC) is underway.

Regional Infrastructure Planning (RIP) for Metro Toronto Region:

PowerStream provided its load forecast to Hydro One for feeders that are a part of Metro Toronto region. The Need Screening process has been completed in 2014. Regional Infrastructure Planning (RIP) for Metro Toronto Region kick off meeting was held on July, 2015. There will be no changes in the number of feeders as well as loading on the feeders from Toronto Region to PowerStream. There is no impact on PowerStream's capital planning/expenditure plans during the term plan. PowerStream will continue to participate in the RIP.

Regional Infrastructure Planning (RIP) for GTA North West Sub-Region:

PowerStream provided its load forecast to Hydro One for feeders that come from Hydro One's stations and VTS3 for the Need Screening in 2014. The Need Screening process has been completed in 2014. Regional Infrastructure Planning (RIP) for GTA North West sub-Region kick off meeting was held in August, 2015. There will be no changes in the number of feeders as well as loading on the feeders in the region. There is no impact on PowerStream's capital planning/expenditure plans during the term plan. PowerStream will continue to participate in the RIP.

South Simcoe (South Georgian Bay/Muskoka Region):

PowerStream is currently involved in the South Simcoe Study for the Southern Georgian Bay/Muskoka Region. The initial Southern Georgian Bay/Muskoka Region Scoping Assessment Outcome Report identified two separate sub-region IRRP's encompassing Barrie/Innisfil and Parry Sound/Muskoka.

Load forecast information for 10 years was provided to Hydro One as part of the initial IESO Needs Screening data gathering process. The Needs Screening identified the end-of-life transformers at Barrie TS, as well as the need for potential capacity increase in the Barrie/Innisfil and Parry Sound/Muskoka regions. The Needs Screening results fed into the Regional Scoping Assessment which identified each sub-region IRRP and respective LDC's and stakeholders. PowerStream has provided the IESO with 20 year load forecasts for each IRRP sub-region, as well as a comprehensive survey of planning methodology and assumptions for each forecast.

The IRRP process is currently in progress and with limited information available at this time PowerStream cannot comment on the impact on the capital planning/expenditure plans that it may have during the 2015-2020 period.

**I-Energy Probe-1**

**Ref: Section I, Tab 1, Schedule 1**

a) What is the current status of the merger announcement made on April 16, 2015?

b) What is the expected closing date of any such merger?

c) Is it possible that the merger could take place before the effective date for rates of January 1, 2016?

d) Has PowerStream reflected any impacts of a potential merger in its application? If not, why not?

e) What are the potential impacts on FTE's of a merger, especially in regards to new positions that may not need to be filled as synergies with the other merger partners may allow for sharing of employees?

f) What are the potential impacts on expenditures on general plant (e.g. vehicles) if a merger takes places and vehicles can be shared across the merged entities?

**RESPONSE:**

a) Please see the response to I-Staff-1b.

b) Please see the response to I-CCC-2.

c) Please see the response to I-CCC-2.

d) No, PowerStream's rate application is “stand-alone”.

e) Please see the response to I-CCC-1-1.

f) Please see the response to I-CCC-1-1.

**I-Energy Probe-2**

**Ref: Section I, Tab 1, Schedule 1 & EB-2014-0138 Report of the Board: Rate-Making Associated with Distributor Consolidation dated March 26, 2015**

a) Please provide the type of incentive rate-making plan that each of the potential merger participants is currently under.

b) Please provide the period for the applicable rate-making plan for each of the potential merger participants.

c) Based on the EB-2013-0138 Report noted above, please provide PowerStream's understanding of when the merged entity could apply to the OEB for cost-of-service rebasing. Please indicate the parts in the Report that lead to this understanding.

**RESPONSE:**

a) PowerStream, Enersource and Hydro One Brampton are currently under Price Cap IR. Horizon is under Custom IR.

b) PowerStream plans to have a Custom IR rate plan for 2016 to 2020. Enersource plans to have a Custom IR rate plan for 2017 to 2021. The Horizon Custom IR rate plan ends at the end of 2019. Hydro One Brampton is on Price Cap IR until the next scheduled rebasing in 2020.

c) Reading the report in its entirety, it is PowerStream’s understanding that the merged entity could apply for rebasing at any time within the ten year deferral period.

**I-Energy Probe-3**

**Ref: Section I, Tab 1, Schedule 1, page 4**

a) What is the status of the new customer care and billing system that went into service in the second quarter of 2015?

b) What was the budgeted cost for this new system and what are the actual costs incurred?

**RESPONSE:**

a) Please see the response to II-SEC-12.

b) Please see the response to II-VECC-2.

**I-Energy Probe-4**

**Ref: Section I, Tab 1, Schedule 1**

Please confirm the figures in Table 1 are consistent with the figures provided in the RRWF's found in Section VI, Tab 25. If this cannot be confirmed, please explain.

**RESPONSE:**

PowerStream confirms that Base Revenue Requirements figures in Section I, Tab 1, Table 1 are consistent with the figures provided in the RRWF's found in Section VI, Tab 25. Revenues at Current Rates, as presented in Section VI, Tab 25 (RRWFs), 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 revenue deficiency drivers (Section I, Tab 1, Table 1), revenue at current rates for each of the year starting 2017 are derived from the revenue requirement of the previous year as applied to the current test year forecast of customers, kWhs and kWs.

**Table I-EP-4-: Revenue Requirement and Revenue at Current Rates ($000)**

| | Reference | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|
| Base Revenue Requirement | Section VI, Tab 25 | 210,325 | 221,430 | 232,012 | 241,643 |
| Revenue at Current Rates (RRWF) - all years at 2015 rates | Section VI, Tab 25 | 162,499 | 163,367 | 164,347 | 165,702 |
| Base Revenue Requirement | Section I, Tab 1, Table 1 | 210,325 | 221,430 | 232,012 | 241,643 |
| Revenue at Current Rates (RRWF) | Section I, Tab 1, Table 1 | 187,845 | 211,294 | 222,673 | 233,848 |

Please note that the revenue requirement amounts have been updated to reflect changes as a result of this round of interrogatories. Please refer to Section A for the changes.

**I-Energy Probe-5**

**Ref: Section I, Tab 3, Schedule 1**

Table 11 shows a WCA factor of 13% for each of 2016 through 2020. On June 3, 2015, the Board issued a letter detailing the Allowance for Working Capital for Electricity Distribution Rate Applications. In that letter the Board states "*For a custom incentive rate-setting (Custom IR) application distributors are expected to file robust evidence of costs and revenues, and the review of these applications is expected to require considerable resources from both the OEB and the distributor. It is therefore reasonable to expect distributors choosing this option to file evidence in support of their requested working capital allowance, rather than the use of a default value."*

a) Has PowerStream filed a lead-lag study as part of the current application? If not, does PowerStream intend to file a lead-lag study, and if so, when will it be filed?

b) Has PowerStream started to move all customers to monthly billing? Please provide details of this movement.

c) Has PowerStream included any incremental costs in the 2015 to 2020 forecasts associated with the movement to monthly billing?

d) Has PowerStream included any incremental cost savings in the 2015 to 2020 forecasts associated with the movement to monthly billing?

**RESPONSE:**

a) PowerStream has not filed a lead-lag study nor is it intending to file one.

b) PowerStream bills Residential customers bimonthly. All other customers are billed monthly. PowerStream recently implemented a new Oracle customer care and billing system (CC&B). PowerStream intends to move Residential customers to monthly billing as of January 1, 2017.

c) No.

d) No.

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**I-SEC-1**

With respect to the potential merger between the PowerStream, Hydro One Brampton, Horizon Utilities and Enersource:

a. Please provide an update on the potential merger.

b. Based on PowerStream's proposed Custom IR rate plan, please provide a list of scenarios in which the rate plan could be terminated because of a merger.

c. If the Board were to order an Earning Sharing Mechanism and/or Efficiency Adjustment Mechanism similar to what the Board approved in the Horizon Utilities Custom IR Application (see EB-2014-0002, Settlement Proposal, filed September 22, 2014) as part of any approvals in the proceeding, please explain any potential implementation issues that PowerStream believes may occur if the merger occurs and is approved.

d. For each of the proposed metrics, please explain any potential implementation issues that PowerStream believes may occur if the merger occurs and is approved.

**RESPONSE:**

a. Please see the response to I-Staff-1-b.

b. Please see the response to I-Staff-1-d.

c. Please see the response to I-CCC-1-5. The same line of reasoning would apply to an Efficiency Adjustment Mechanism.

d. Please see the response to I-AMPCO-1-b.

**I-SEC-2**

Please provide all Board required appendices in a single excel file.

**RESPONSE:**

PowerStream has provided all required Board appendices.  Some appendices are quite large in size/volume and have multiple sheets and it would not be practical to combine them in a single file.

**I-SEC-3**

On the same basis as provided in each of the listed appendices, please provide i) 2015 January-June half-year actuals, and ii) 2014 January-June half-year actuals.

a. 2-AA
b. 2-AB
c. 2-JB
d. 2-JC
e. 2-H

**RESPONSE:**

a. See 2011-2014 Project List as Appendix SEC-3a – Project Listing, with an additional column for 2014 Jan-June totals.

b. Refer to Table SEC-3b below for the 2011-2020 Capital Expenditure Summary, by 4 OEB Categories, with additional columns for 2014 and 2015 half year actuals.

**Table SEC-3b**

| | | | | | | Bridge | | Forecast (Planned) | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2011 | 2012 | 2013 | 2014 | 2014 | 2015 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
| CATEGORY | Actual | Actual | Actual | Actual | Jan-June Actual | Plan | Jan-June Actual | Plan | Plan | Plan | Plan | Plan |
| Rate Base | $ '000 | $ '000 | $ '000 | $ '000 | $ '000 | $ '000 | $ '000 | $ '000 | $ '000 | $ '000 | $ '000 | $ '000 |
| System Access | 21,007 | 19,888 | 17,030 | 26,229 | 6,335 | 24,145 | 6,370 | 28,232 | 28,470 | 29,561 | 28,726 | 31,867 |
| System Renewal | 11,527 | 16,974 | 22,254 | 39,186 | 12,838 | 42,388 | 20,779 | 48,715 | 51,500 | 52,052 | 52,971 | 52,406 |
| System Service | 22,885 | 13,770 | 34,780 | 17,946 | 11,259 | 27,322 | 5,859 | 38,322 | 32,072 | 29,920 | 26,963 | 23,022 |
| General Plant | 7,877 | 24,200 | 19,593 | 26,148 | 10,136 | 24,545 | 12,099 | 17,631 | 19,558 | 13,967 | 16,841 | 18,206 |
| Sub-Total | 63,297 | 74,832 | 93,657 | 109,509 | 40,568 | 118,400 | 45,107 | 132,900 | 131,600 | 125,500 | 125,501 | 125,500 |
| Non-Rate Base | 2,278 | 1,196 | 2,628 | 1,364 | 543 | 2,489 | 457 | - | - | - | - | - |
| Grand Total | 65,575 | 76,028 | 96,285 | 110,873 | 41,111 | 120,889 | 45,564 | 132,900 | 131,600 | 125,500 | 125,501 | 125,500 |
| System O&M | 2,055 | 2,438 | 2,523 | 2,627 | 840 | 3,290 | 1,146 | 3,825 | 4,365 | 4,909 | 5,459 | 6,015 |

c. 2-JB: please see the updated table below, this shows the June YTD 2014 compared to June YTD 2015 actuals.

| Total OM&A (000's) | June 2014 Actual YTD | June 2015 Actual YTD |
|---|---|---|
| **Opening Balance June YTD** | **$ 35,724** | **$ 40,955** |
| | | |
| Compensation | 277 | 295 |
| Asset Management | 1,529 | (33) |
| Vegetation Management | 57 | 90 |
| CIS Implementation | 806 | 470 |
| Risk Management | 154 | 103 |
| Growth | 95 | 181 |
| Customer Expectation | - | 337 |
| Compliance | - | 495 |
| Other | 2,313 | (205) |
| | | |
| **Closing Balance June YTD** | **$ 40,955** | **$ 42,688** |

d. 2-JC: table below is updated with 2014 and 2015 January to June half year actual columns. The totals in each of these columns are the actual June year to date results.

| Programs (000's) | Last Rebasing Year (2013 Board-Approved)** | Last Rebasing Year (2013 Actual) | 2014 Actual | 2014 Jun30 YTD Actuals | 2015 Jun30 YTD Actuals | 2015 Bridge Year |
|---|---|---|---|---|---|---|
| **Asset Management** | | | | | | |
| Smart Grid | $ - | $ - | $ - | $ - | $ - | $ - |
| System Control | $ 3,343 | $ 3,408 | $ 3,653 | $ 1,737 | $ 1,850 | $ 3,837 |
| Lines | $ 12,046 | $ 13,919 | $ 13,040 | $ 6,107 | $ 6,209 | $ 14,161 |
| Protection and Control | $ 1,512 | $ 1,327 | $ 1,353 | $ 623 | $ 757 | $ 1,464 |
| Stations | $ 2,055 | $ 1,795 | $ 2,079 | $ 995 | $ 1,154 | $ 2,174 |
| Metering | $ 3,478 | $ 2,988 | $ 3,696 | $ 1,951 | $ 1,784 | $ 3,652 |
| Asset Investment Planning | $ 2,986 | $ 2,718 | $ 3,024 | $ 1,492 | $ 1,344 | $ 3,301 |
| Engineering Design Distribution | $ 3,983 | $ 3,758 | $ 3,948 | $ 1,580 | $ 1,644 | $ 4,040 |
| Engineering and Operations Strategy | $ 2,460 | $ 2,356 | $ 2,587 | $ 1,217 | $ 1,258 | $ 2,777 |
| **Subtotal** | **$ 31,864** | **$ 32,270** | **$ 33,379** | **$ 15,702** | **$ 16,000** | **$ 35,405** |
| | | | | | | |
| **Finance** | | | | | | |
| Rates and Regulatory Affairs | $ 2,778 | $ 2,363 | $ 3,074 | $ 1,331 | $ 1,831 | $ 3,259 |
| Customer Service | $ 14,124 | $ 13,642 | $ 16,089 | $ 7,902 | $ 7,148 | $ 16,711 |
| Corporate Finance and Reporting | $ 5,386 | $ 5,124 | $ 5,138 | $ 2,485 | $ 2,533 | $ 5,701 |
| **Subtotal** | **$ 22,289** | **$ 21,129** | **$ 24,301** | **$ 11,718** | **$ 11,512** | **$ 25,672** |
| | | | | | | |
| **Corporate Services** | | | | | | |
| Supply Chain Services | $ 5,812 | $ 5,514 | $ 5,737 | $ 2,984 | $ 3,055 | $ 5,979 |
| Information Services | $ 6,904 | $ 6,458 | $ 6,061 | $ 2,957 | $ 4,037 | $ 9,132 |
| Corporate Communications | $ 1,399 | $ 1,431 | $ 1,740 | $ 736 | $ 818 | $ 1,806 |
| Legal | $ 479 | $ 385 | $ 351 | $ 170 | $ 212 | $ 513 |
| Human Resources and Organizational Effectiveness | $ 4,870 | $ 5,037 | $ 5,125 | $ 2,557 | $ 2,627 | $ 5,458 |
| Corporate | $ 5,588 | $ 4,968 | $ 5,667 | $ 2,559 | $ 2,945 | $ 5,364 |
| Strategic Direction | $ 3,736 | $ 3,655 | $ 3,092 | $ 1,573 | $ 1,482 | $ 3,227 |
| **Subtotal** | **$ 28,788** | **$ 27,450** | **$ 27,774** | **$ 13,536** | **$ 15,176** | **$ 31,480** |
| | | | | | | |
| **Total** | **$ 82,941** | **$ 80,849** | **$ 85,454** | **$ 40,955** | **$ 42,688** | **$ 92,558** |

e. The below table is updated with the six months of 2014 and 2015 actuals.

| USoA # | USoA Description | 2013 Board-Approved* | 2013 Actuals | 2014 Actuals | June YTD Actual | June YTD Actual | Bridge Year[3] | TEST YEAR 1 | TEST YEAR 2 | TEST YEAR 3 | TEST YEAR 4 | TEST YEAR 5 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | 2014 | 2015 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
| | *Reporting Basis* | MIFRS | MIFRS | MIFRS | MIFRS | MIFRS | MIFRS | MIFRS | MIFRS | MIFRS | MIFRS | MIFRS |
| **Special Service Charges** | | | | | | | | | | | | |
| 4235 | Specific Service Charges | **3,385,000** | **3,463,771** | **3,478,694** | **1,646,607** | **1,405,940** | **3,488,043** | **3,471,316** | **3,474,784** | **3,475,039** | **3,474,966** | **3,476,285** |
| **Late Payment Charges** | | | | | | | | | | | | |
| 4225 | Late Payment Charges | **2,500,000** | **1,923,553** | **2,182,713** | **1,104,877** | **854,786** | **2,022,227** | **2,038,288** | **2,076,532** | **2,045,682** | **2,053,501** | **2,058,572** |
| **Other Distribution Revenue** | | | | | | | | | | | | |
| 4078 | SSS Administration Charge | 932,400 | 968,592 | 996,403 | 490,525 | 514,573 | 1,014,425 | 1,032,693 | 1,051,477 | 1,070,630 | 1,089,911 | 1,109,662 |
| 4082 | Retail Services Revenues | 399,600 | 234,984 | 212,405 | 107,206 | 100,545 | 216,247 | 220,141 | 224,145 | 228,228 | 232,339 | 236,549 |
| 4210 | Rent from Electric Property | 700,000 | 744,022 | 757,373 | 386,628 | 369,722 | 746,560 | 748,260 | 749,673 | 748,165 | 748,699 | 748,846 |
| 4245 | Government & Other Assistance Directly Credited to Income | - | 1,887,586 | - | | | - | - | - | - | - | - |
| 4245 | Government & Other Assistance Directly Credited to Income ( Note 1) | - | (1,887,586) | - | | | - | - | - | - | - | - |
| **Sub total** | | **2,032,000** | **1,947,598** | **1,966,180** | **984,359** | **984,840** | **1,977,232** | **2,001,095** | **2,025,296** | **2,047,023** | **2,070,949** | **2,095,056** |
| **Other Income or Deductions** | | | | | | | | | | | | |
| 4324 | Special Purpose Charge Recovery | - | (449) | - | - | (0) | - | - | - | - | - | - |
| 4355 | Gain on Disposition of Utility and Other Property | - | 75,771 | 46,182 | 23,360 | 115,171 | - | - | - | - | - | - |
| 4362 | Loss from Retirement of Utility and Other Property | - | (1,462,182) | (2,078,248) | (474,260) | (631,126) | (1,500,000) | (1,300,000) | (1,300,000) | (1,300,000) | (1,300,000) | (1,300,000) |
| 4375 | Revenues from Non Rate-Regulated Utility Operations | 32,993,598 | 23,653,392 | 27,719,176 | 1,718,887 | 1,693,494 | 3,641,949 | 3,759,090 | 3,850,269 | 3,925,633 | 4,027,688 | 4,130,311 |
| 4380 | Expenses from Non Rate-Regulated Utility Operations | (28,500,000) | (19,955,141) | (24,140,021) | | | - | - | - | - | - | - |
| 4385 | Non Rate-Regulated Utility Rental Income | - | 5,677 | 4,909 | 2,668 | (10) | - | - | - | - | - | - |
| 4390 | Miscellaneous Non-Operating Income | 1,020,000 | 2,233,238 | 2,673,172 | 289,835 | 580,323 | 1,115,667 | 1,078,814 | 1,049,431 | 1,081,304 | 1,069,850 | 1,066,861 |
| 4405 | Interest & Dividend Income | 125,000 | 338,792 | 239,331 | 136,093 | 194,464 | 260,000 | 260,000 | 260,000 | 260,000 | 260,000 | 260,000 |
| 4420 | Share of Profit or Loss of Joint Venture | - | 313,794 | 307,982 | | | 300,000 | 300,000 | 300,000 | 300,000 | 300,000 | 300,000 |
| 4324 | Special Purpose Charge Recovery (Note 2) | - | 449 | - | | | - | - | - | - | - | - |
| 4362 | Loss from Retirement of Utility and Other Property (Note 2) | - | 1,462,182 | 2,078,248 | 474,260 | 631,126 | 1,500,000 | 1,300,000 | 1,300,000 | 1,300,000 | 1,300,000 | 1,300,000 |
| 4375 | Revenues from Non Rate-Regulated Utility Operations (Note 2) | (29,270,000) | (20,019,143) | (24,215,458) | (8,929) | (8,929) | (18,000) | (18,000) | (18,000) | (18,000) | (18,000) | (18,000) |
| 4380 | Expenses from Non Rate-Regulated Utility Operations (Note 2) | 28,500,000 | 19,955,141 | 24,140,021 | - | - | - | - | - | - | - | - |
| 4385 | Non Rate-Regulated Utility Rental Income (Note 2) | - | (5,677) | (4,909) | (2,668) | 10 | - | - | - | - | - | - |
| 4420 | Share of Profit or Loss of Joint Venture (Note 2) | - | (313,794) | (307,982) | - | - | (300,000) | (300,000) | (300,000) | (300,000) | (300,000) | (300,000) |
| **Sub total** | | **4,868,598** | **6,282,049** | **6,462,403** | **2,159,247** | **2,574,523** | **4,999,616** | **5,079,905** | **5,141,699** | **5,248,937** | **5,339,537** | **5,439,173** |
| | | | | | | | | | | | | |
| **TOTAL** | | **12,785,598** | **13,616,971** | **14,089,989** | **5,895,089** | **5,820,089** | **12,487,117** | **12,590,603** | **12,718,312** | **12,816,681** | **12,938,953** | **13,069,086** |

* OEB 2013 Approved Budget is $ 9,844,598. Difference of $ 2,941,000 relates to Joint Services Revenue included in Other Operating Revenue.

NOTES:

1 - For Revenue Offsets calculation, the amount in account 4245 are not included in Other Operating Revenues .

2 - For Revenue Offsets calculation, the amount in account 4105, 4110, 4230, 4305, 4324, 4362, 4375, 4380, 4385 & 4420 are not included in Other Income or Deductions .

3 - The amounts in account 4405 are net of interest on Regulatory Assets and interest on Customer Deposits

**I-SEC-4**

Please provide a summary of all internal audit reports/findings from the last 5 years. Please provide a list of all recommendations and their implementation status.

**RESPONSE:**

Internal Audit performs independent assessments of risks and controls on behalf of PowerStream's Audit & Finance Committee of the Board. This governance function ensures that there is open communication of these risks between Management and the Audit & Finance Committee of the Board, and that PowerStream is proactive in identification and resolution of any areas of concern.

The scope of Internal Audit is set by a risk-based Internal Audit plan that is reviewed with the Audit & Finance Committee of the Board on an annual basis to ensure the resources are expended on the areas that will bring the most value.

All Internal Audit reports are confidential documents that are intended for the Management of the respective Business Unit(s), Executive Management and the Audit & Finance Committee of the Board.

Confidentiality is essential to the Internal Audit process, to ensure that all parties participate in open communication of issues with the mutual objective of improving processes and controls within PowerStream. Sharing the Internal Audit findings in a public setting, such as an OEB Rate Filing, would undermine the Internal Audit process. The Internal Audit reports are not openly distributed, not even amongst Senior Management, unless they are directly affected by the particular findings.

Even filing the requested information in confidence would be cumbersome, at best. Company witnesses and other company participants in the proceeding would either have access to such information or would have to have access to the information to be able to deal with any matters raised in the proceeding in connection with the Internal Audit reports.

For the above reasons, PowerStream has not provided the specific information requested in this interrogatory. PowerStream would be amenable to discussing this with SEC during the Technical Conference, or even prior, how it can provide information that could address SEC's interest on the topic without concerns around confidentiality, undermining Internal Audit objectives, endangering the long-standing and effective internal company practices, and not introducing complexities in the proceeding around how to handle and deal with the topic.

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**I-SIA-1**

**Ref: Section I, Tab 1, Schedule 1, page 1**

PowerStream explains its need for a Custom IR application primarily on the need to fund its capital program.

a) Does PowerStream also consider its OM&A requirements as a reason for the need to file a CIR application?

b) Please explain what unique challenges PowerStream faces in terms of OM&A spending drivers that would justify a unique approach to OM&A funding. That is, why would a custom approach to capital investment but a standard (I-X) approach to OM&A (using the 4th Generation IRM parameters) not be appropriate for PowerStream's circumstances?

**RESPONSE:**

a) PowerStream considered all the components of revenue requirement when it decided to file the Custom IR application. Essentially, the 4th Generation IR, which has the same rate adjustment mechanisms as the current incentive regulation and incremental capital module, does not adequately support both increasing capital needs as well as changes to OM&A costs. Significant rate increases generally materialize when rebasing of OM&A and capital occur every three to four years. The Custom IR option better matches costs with revenues/rates in the period they occur, which will also assist in minimizing rate increases attributable to rebasing on a single year.

b) There are a number of drivers for OM&A that justify the Custom IR approach. Firstly, as noted in the response to II-1-Staff-12 and II-1-Staff-24 there are a number of extra-ordinary items that should be considered outside of the IPI-X approach. These include the new CC&B system and the vegetation management program which are explained in detail in response II -1-Staff-24.

   Secondly, as noted in Section II, Exhibit H, Tab 3, Table 5 of the application, PowerStream has a projected increase in customers over the test years. As a result this drives an increase in capital assets which drives an increase in OM&A. This increase is not incorporated into the standard IPI-X formula and thus a custom approach would be more appropriate.

Lastly, the IPI-X formula does not incorporate work force management challenges which are incorporated in the risk management OM&A cost driver. For example PowerStream has an aging workforce that requires PowerStream to plan and pre-hire in order to ensure there are no risks in system operation and the ability to provide safe and reliable service. These costs cannot be managed through a standard IPI-X formula.

As a result of these above drivers a Custom IR approach is more appropriate.

# Section II

**II-1-Staff-8**

**Ref: E A/T1**

a) What specific outcomes does PowerStream target for its planned OM&A and capital spending over the five year plan term (e.g. reduction in unit cost to targeted level, reduction in outage length by x %)?

b) How is progress toward the targeted outcomes to be quantified?

c) By what metric of performance will success in achieving the outcome be demonstrated?

d) How is the value to customers of the proposed spending over the plan term to be demonstrated?

e) What consequences should occur if targeted outcomes are exceeded? If targeted outcomes are not achieved?

f) Please describe how each of the targeted outcomes aligns with customer preferences identified by PowerStream, with reference to the evidence in this application.

**RESPONSE:**

a) As discussed in section II, Tab 1, Exhibit F, Tab 1, PowerStream's goal for OM&A is, after accounting for new requirements and costs, to maintain OM&A spending at a level that produces the same productivity savings as under the price cap regime of IPI-X.

PowerStream's level of capital spending is designed for modest improvements in reliability to bring PowerStream's metrics back in line with historical performance. Please refer to Section III, Tab 1, Schedule 1, page 133, interrogatory response to G-AMPCO-7, part (e) for details of the SAIDI Reliability target.

b) PowerStream considers the OEB Scorecard the key external metric for the Board to monitor its performance along with the RRR information filed.

c) Please refer to the responses to parts (a) and (b) above.

d) Please refer to the responses to parts (a) and (b) above.

e) PowerStream is committed to its plan and has good processes in place to enable it to deliver. If PowerStream was to achieve greater efficiencies / savings these will accrue to ratepayers through a lower rate base and a lower OM&A cost base going forward. If PowerStream fails to achieve the efficiencies and savings built into its plan then it will earn less than the Board's allowed rate of return. The customer satisfaction metric, in particular, on the OEB Scorecard helps PowerStream gauge the value that customers perceive. The customer satisfaction measure includes many factors, including the customer experience with the frequency and duration of outages. Please also see the response to III-VECC-13.

f) Please refer to Section VI, Tab 3, Schedule 1 for Appendix 2-AC, Customer Engagement Activities Summary. Customer preferences indicated a desire for increased reliability and a concern with outages but also expressed a concern with cost. Some customer groups expressed greater concern with reliability than cost.

The outcomes identified in part (a) above are PowerStream's plan to balance an improvement in reliability and reduction in outages with measures to control the costs.

**II-1-Staff-9**

**Ref: E B/T1/pp.1-2**

In discussing the bill impacts arising from the application, PowerStream divides the impacts into the categories of "Extraordinary items" and "Business as usual." The former category includes such items as the replacement of PowerStream's billing system, storm hardening capital and OM&A expenditures and a new transformer station. It is stated that "Business as usual" consists of capital additions and increases in OM&A expenditures in the rebasing year excluding these extraordinary items.

Please discuss the criteria used by PowerStream to determine if an expenditure was an extraordinary or business as usual item.

**RESPONSE:**

"Business as usual" items are expenditures that occur regularly. The extraordinary items represent expenditures that do not occur regularly or represent a significant and unusual change in the level of expenditure.

**II-1-Staff-10**

**Ref: E F/T1 and Ontario Energy Board EB-2013-0416/EB-2014-0247 Hydro One Networks Inc. *Decision* March 12, 2015, p.8**

In the first reference, PowerStream discusses its approach to productivity.

In the second reference, it is stated that:

> However, the OEB notes that, despite having applied under the Custom IR framework, Hydro One characterized its application as a "Custom Cost of Service" application. The company indicated that cost savings from productivity improvements were embedded in cost forecasts, and that the company would bear the risk of failing to achieve these savings. The OEB does not consider Hydro One's "Custom Cost of Service" application to be sufficiently aligned with the objectives of the RRFE policy to approve the application as presented. Also, the OEB does not consider it acceptable to postpone the potential commencement of an appropriately-structured **incentive based** rate setting framework until 2020 following the five-year period proposed by Hydro One.

a) Please state why the criticisms the OEB made in the Hydro One Decision referenced above would not be equally applicable to PowerStream's application.

b) Please state why PowerStream did not commission an external study of its productivity similar to that included by Toronto Hydro-Electric System Limited in its Custom IR application (EB-2014-0116) "Econometric Benchmarking of Historical and Projected Total Cost and Reliability Levels, 31 Jul 2014, prepared by Power System Engineering Inc."

c) In the event, the OEB was to determine that such an external study would be helpful to it in assessing PowerStream's productivity, please state any concerns PowerStream would have with producing such a study.

**RESPONSE:**

a) Please refer to the responses to A-CCC-1, A-CCC-3 and A-CCC-5 in Section III, Tab 1 of the Application.

b) PowerStream believed that the evidence it provided on Benchmarking was sufficient.

c) PowerStream has no concerns with providing such as study if the Board deems this necessary and provides for recovery of the costs of the study through rates.

**II-1-Staff-11**

**Ref: E F/T1/p.5/Table 4**

The above reference provides estimated productivity savings from OM&A. The savings are calculated off the "Status Quo" OM&A which is stated as "determined by taking the most recent 2013 Board Approved OM&A and adjusting for significant cost drivers affecting OM&A costs such as inflationary wage and price increases, growth and other identified cost drivers."

a) Please state why PowerStream believes that the most recent 2013 Board Approved OM&A is an appropriate base to be used to determine productivity savings.

b) Please provide an alternate version of Table 4 using 2013 actual OM&A in place of 2013 Board Approved OM&A.

**RESPONSE:**

a) PowerStream has used the 2013 Board Approved Cost of Service OM&A as the base since this was deemed by the Board to be the appropriate OM&A starting point for the subsequent incentive regulation period. PowerStream notes that the 2013 Actual OM&A was $1,442,000 lower than the 2013 Board approved OM&A due to temporary savings that will not reoccur in the rate plan years. These savings related to higher than normal vacancies that occurred in 2013, therefore the 2013 actuals do not include PowerStream's full complement of staff. There was also a one-time property tax rebate of $397,000 which was received in 2013. Accordingly the 2013 Actual OM&A is not a suitable base.

b) Table II-1-Staff-11 below is provided in response to this interrogatory.

**Table II-1-Staff-11: Alternative Version of Table 4 ($ thousands)**

| | | | | Custom IR Term | | | | |
|---|---|---|---|---|---|---|---|---|
| "Expected OM&A" | 2013 Actual | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
| Approved/Prior year OM&A start | $ 80,849 | $ 80,849 | $ 85,394 | $ 89,233 | $ 92,568 | $ 95,682 | $ 98,329 | $ 101,403 |
| Inflation adjustment | | $ 1,374 | $ 1,366 | $ 1,963 | $ 2,036 | $ 2,105 | $ 2,163 | $ 2,231 |
| Customer growth adjustment | | $ 177 | $ 167 | $ 173 | $ 182 | $ 186 | $ 191 | $ 200 |
| Net incremental new costs | | $ 2,994 | $ 2,305 | $ 1,200 | $ 895 | $ 356 | $ 719 | $ 484 |
| Expected OM&A | $ 80,849 | $ 85,394 | $ 89,233 | $ 92,568 | $ 95,682 | $ 98,329 | $ 101,403 | $ 104,318 |
| Actual and Projected OM&A in Application | $ 80,849 | $ 85,454 | $ 92,558 | $ 96,216 | $ 98,112 | $ 99,920 | $ 102,195 | $ 104,193 |
| Variance/Productivity savings (cost) | | ($60) | ($3,325) | ($3,648) | ($2,430) | ($1,591) | ($792) | $125 |

**II-1-Staff-12**

**Ref: E F/T1/p.6/Table 6 and E J/T1/p.2/Table 1**

The first of the above references, Table 6, provides the derivation of the net incremental new costs category shown in Table 4. These costs are from the second reference Table 1 which is entitled "Net Incremental New Costs for Changing Requirements and Extraordinary Items," specifically the "Compliance," "Risk Management," and "Customer Expectation" categories from the "Business as usual" section of Table 1 and the "Vegetation Management" and "CIS Implementation" categories from the "Extra-ordinary items" section of Table 1.

a) Please state why "Vegetation Management" and "CIS Implementation" would be considered as "Extra-ordinary items" while the remaining categories would be "Business as usual." Please discuss in the context of vegetation management and CIS costs being ongoing business as usual costs for most distributors.

b) Please state what the "Other" category in Table 1 consists of.

c) Please state for Table 1 whether all work force-related costs were separated out into the "Compensation" category from the other categories in the table such as "Vegetation Management" and "CIS Implementation" and how this was done, or if not please state which workforce-related costs remain in the other categories.

**RESPONSE:**

a) Vegetation management and CIS implementation are extra-ordinary because of their significant incremental impact on OM&A. The Vegetation management program in particular new and came about as a result of the 2013 ice storm, as described in detail in the answer to Section III, Tab 1, Schedule 1, J-CCC-61.

b) "Other" captures activities or costs that are not easily attributable to individual work programs or work areas. Included in this category are incremental contract consulting, training, legal fees and miscellaneous expenses.

c) Included in the compensation driver is merit and step increases related to all business units. New hires and overtime are included in the other cost drivers in which they relate.

**II-1-Staff-13**

**Ref: E F/T1/pp.6-7**

At the above reference the productivity changes arising from PowerStream's plans to rehabilitate 140 kilometres of end-of-life or beyond underground cable in 2015 and each year during the 2016 to 2020 IR plan term.

a) Please confirm that this is the only capital program that PowerStream is including in determining its estimated productivity savings from capital or if not please explain.

b) Please state the criteria used by PowerStream to determine that a particular capital program produced productivity savings versus those programs which did not produce such savings.

**RESPONSE:**

a) PowerStream confirms that cable injection is the only program that was included in the calculation of productivity savings from capital. The pole reinforcement program was discussed but the savings from this program were not calculated nor included in the estimated productivity savings.

b) PowerStream is continually working to improve its processes to be more effective and efficient as evidenced by its Organization Effectiveness department, Journey to Excellence and Innovation initiatives.

PowerStream has not attempted to measure the productivity of all capital programs. This is a very difficult task as no two capital projects are the same – there are always many different factors. For example pole line replacement projects will have differing pole heights, number of circuits and differences in terrain and other work conditions that significantly impact the cost of the project and any resulting metric such as cost per pole or cost per kilometre of line.

PowerStream selected the cable injection program to demonstrate the work PowerStream has been doing in productivity improvements as the program has significant costs with substantial productivity savings. By the use of this innovative program PowerStream has managed to extend the life of underground cables at a fraction of the cost of replacement. Other capital projects may also contain productivity savings but PowerStream has not attempted to measure these.

**II-1-Staff-14**

**Ref: E F/T1/p.7/Table 7**

The above table provides the derivation of additional productivity savings from capital.

a) Please confirm that the savings shown in the table are expenses dollars rather than capital dollars, or if not, please explain.
b) Please provide an explanation as to how these savings were derived starting from the capital costs which were incurred to achieve the savings. Please include an explanation as to whether or not the ongoing costs of the capital expenditures for the cable injection program have been included in these calculations and if so, how. If not, please explain.

**RESPONSE:**

a) The amounts shown in Table 7, as referenced above, are capital spending dollar savings. Please see Section III, Tab 1, Ex. F, page 93 ff. In this response to interrogatory F-SEC-6, PowerStream converts the capital productivity savings to revenue requirement for comparison with the OEB expected productivity "X" factor.

b) The savings are based on the PowerStream's latest research and analysis on cable injection which will allow an additional 22 kilometers of cable to be injected rather than replaced each year from 2015 to 2020. PowerStream has not included the productivity savings from the previously planned level of cable injection for 2015 to 2020 nor has it included the ongoing savings resulting from the cable injections that have been done in earlier years.

The cable injection productivity savings were calculated as the difference between the capital cost of replacing the cable and the capital cost of injecting the cable as summarized in Table II-1-Staff-14 below.

**Table II-1-Staff-14: Capital Costs and Savings – Cable Injection**

| | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
|---|---|---|---|---|---|---|
| Replacement cost | $ 10,312,599 | $ 11,034,056 | $ 11,974,424 | $ 12,573,704 | $ 13,275,592 | $ 13,499,376 |
| Injection Cost | $ 867,969 | $ 791,677 | $ 814,089 | $ 837,104 | $ 860,740 | $ 885,016 |
| Savings | $ 9,444,630 | $ 10,242,379 | $ 11,160,335 | $ 11,736,600 | $ 12,414,852 | $ 12,614,360 |
| Adjusted Savings[1] | $ 3,777,852 | $ 4,096,952 | $ 4,464,134 | $ 4,694,640 | $ 4,965,941 | $ 5,045,744 |

Note: Injected cable has a forecast useful life of 20 years versus a useful life of 50 years for replacement cable. The capital cost savings adjusted to 40% of the capital savings to measure the productivity savings resulting from utilizing this technology by comparing on a comparable basis, i.e. achievement of the same output (20 years of service life) with reduced inputs (cost)

**II-1-Staff-15**

**Ref: E G/T 2, Consolidated Distribution System Plan**

Please provide the copies of the following studies, reports, analyses that are mentioned in the DSP:

a) The latest Worst Performing Feeders study.

b) The latest "*Feeder Balancing and System Reconfiguration Plan*".

c) The latest long-term load forecast and system capacity study for PowerStream territories.

d) The latest version of PowerStream's Annual Distribution Inspection and Maintenance Programs.

e) PowerStream's 2012 Distribution Automation Report.

f) A copy of the engineering consultant report used by PowerStream to justify the Highway Crossing Remediation program.

g) Any other study or report that was used to develop the DSP and has not been provided in the current application

**RESPONSE:**

Table 15a summarizes the submitted references for the requested studies, reports, analyses that are mentioned in the DSP.

**Table 15a**

| Report | PDF File Name |
|---|---|
| a) Worst Performing Feeders | Appendix Staff 15a - Worst Performing Feeders – 2015 |
| b) Feeder Balancing and System Reconfiguration Plan | Appendix Staff 15b.1 - 2015 System Reconfiguration South Report<br>Appendix Staff 15b.2 - PS North 2015 Feeder Balance and System reconfiguration Report – May 2015 – REV 2 |
| c) Latest long-term load forecast and system capacity study for PowerStream | Appendix Staff 15c.1 - PowerStream South Load Forecast 2-15-2014 Rev.4<br>Appendix Staff 15c.2 - 2015 to 2024 PowerStream North Load Forecast – DRAFT 5 |

| | | |
|---|---|---|
| | territories | |
| d) | Latest version of PowerStream's Annual Distribution Inspection and Maintenance Programs | *The results of I&M programs are in various formats, sizes and the asset registries are not practical to supply.* |
| e) | 2012 Distribution Automation Report | Appendix Staff 15e - Distribution Automation Report Rev 1 |
| f) | Highway Crossing Remediation | Appendix Staff 15f.1 - P144-1_High_Level_Risk_Assessment_Part_1_Report<br>Appendix Staff 15f.2 - P144-2_High_Level_Risk_Assessment_Report_Part_2<br>Appendix Staff 15f.3 - P144-3_High_Level_Risk_Assessment_Report_Part_3<br>Appendix Staff 15f.4 - P144-4_High_Level_Risk_Assessment_Report_Part_4 |

**II-1-Staff-16**

**Ref: E G/T 2, Distribution System Plan Summary**

Please provide the following information for each of the DSP investment categories and project/material sub-projects, if available, for each of the years 2011 – 2020, in sufficient detail to calculate the investment amounts in the DSP:

a) Number of asset units installed and to be installed.

b) Number of asset units removed and to be removed.

c) Capitalized cost per asset units.

d) Please discuss any trends in capitalized cost per asset over the period, with specific reference to a) inflation trends and b) productivity measures.

If any of the requested information is not available, please provide an explanation.

**RESPONSE:**

a) A significant portion of the DS Plan is based on specific projects. PowerStream does not track, as a whole, installed units or per unit cost for these projects. Table 16a below provides asset units installed and to be installed for the asset condition assessment programs. For similar emergency asset replacements refer to G-AMPCO-24 and G-AMPCO-25, Sec III, Tab 1, Schedule 1, Pgs. 161 and 162.

## Table 16a

| Assets | | Actual | | | | Planned | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
| Transformer Station Power Transformers (ACA) | # of Units | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | $ | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | $/Unit | - | - | - | - | - | - | - | - | - | - |
| Municipal Station Power Transformers (ACA) | # of Units | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | $ | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | $/Unit | - | - | - | - | - | - | - | - | - | - |
| Transformer and Municipal Station Circuit Breakers | # of Units | 8 | 9 | 5 | 4 | 7 | 12 | 12 | 10 | 8 | 6 |
| | $ | $1,286,493 | $1,314,020 | $840,463 | $375,395 | $1,219,194 | $2,223,194 | $2,215,878 | $2,616,350 | $2,403,406 | $1,367,315 |
| | $/Unit | $160,812 | $146,002 | $168,093 | $93,849 | $174,171 | $185,266 | $184,657 | $261,635 | $300,426 | $227,886 |
| Transformer Station 230 kV Primary Switches (ACA) | # of Units | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | $ | $0 | $61,541 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | $/Unit | - | $61,541 | - | - | - | - | - | - | - | - |
| Municipal Station Primary Switches (ACA) | # of Units | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | $ | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | $/Unit | - | - | - | - | - | - | - | - | - | - |
| Transformer Station Capacitor Banks (ACA) | # of Units | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | $ | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | $/Unit | - | - | - | - | - | - | - | - | - | - |
| Transformer Station Reactors (ACA) | # of Units | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | $ | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | $/Unit | - | - | - | - | - | - | - | - | - | - |
| TS Station Service Transformers (ACA) | # of Units | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | $ | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | $/Unit | - | - | - | - | - | - | - | - | - | - |
| TS 230 kV Primary Metering Units (ACA) | # of Units | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | $ | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | $/Unit | - | - | - | - | - | - | - | - | - | - |
| Protection and Control Relays | # of Units | | | | | | | | | | |
| | $ | | | | | | | | | | |
| | $/Unit | | | | | | | | | | |
| Protection and Control RTUs | # of Units | | | | | | | | | | |
| | $ | (1) | | | | (1) | | | | | |
| | $/Unit | | | | | | | | | | |
| Spare Breakers and Switchgear Cells | # of Units | | | | | | | | | | |
| | $ | | | | | | | | | | |
| | $/Unit | | | | | | | | | | |
| Miscellaneous Spare Parts | # of Units | | | | | - | multi | multi | multi | multi | multi |
| | $ | (1) | | | | - | $48,631 | $48,632 | $48,632 | $48,631 | $48,632 |
| | $/Unit | | | | | - | N/A | N/A | N/A | N/A | N/A |

*Note* (1) not available

| Assets | | Actual | | | | Planned | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
| Underground Cable (Injection) | length (m) | 9,570 | 25,100 | 85,363 | 106,976 | 102,000 | 80 - 100 km | 80 - 100 km | 80 - 100 km | 80 - 100 km | 80 - 100 km |
| | $ | $315,776 | $810,310 | $4,319,470 | $6,006,747 | $4,024,219 | $4,138,312 | $4,255,465 | $4,375,771 | $4,499,323 | $4,626,219 |
| | $/m | $33 | $32 | $51 | $56 | $39 | $41 - $52 | $43 - $53 | $44 - $55 | $45 - $56 | $46 - $58 |
| Underground Cable (Replacement) | length (m) | 10,330 | 9,060 | 49,539 | 54,499 | 25 - 30 km | 25 - 30 km | 25 - 30 km | 25 - 30 km | 25 - 30 km | 25 - 30 km |
| | $ | $2,829,932 | $1,931,017 | $14,722,080 | $14,982,276 | $11,718,862 | $12,538,684 | $13,607,273 | $14,288,297 | $15,085,861 | $15,340,181 |
| | $/m | $274 | $213 | $297 | $275 | $391 - $469 | $418 - $502 | $454 - $544 | $476 - $572 | $503 - $603 | $511 - $614 |
| Fault Indicator Replacement Program | # of Units | 779 | 1,171 | 1,940 | 1,547 | 1650 | 1650 | 1650 | 1650 | 1650 | 1650 |
| | $ | $46,173 | $326,565 | $527,405 | $484,511 | $500,000 | $500,000 | $500,000 | $500,000 | $500,000 | $500,000 |
| | $/Unit | $59 | $279 | $272 | $313 | $303 | $303 | $303 | $303 | $303 | $303 |
| Porcelain Insulators | # of Units | - | - | - | - | 275 | 275 | 275 | 275 | 275 | 275 |
| | $ | - | - | - | - | $66,000 | $68,000 | $69,000 | $71,000 | $71,000 | $71,000 |
| | $/Unit | - | - | - | - | $240 | $247 | $251 | $258 | $258 | $258 |
| Submersible Transformers | # of Units | 20 | 32 | 24 | 10 | 8 | 4 | - | - | - | - |
| | $ | $479,131 | $812,985 | $1,263,913 | $870,247 | $1,040,300 | $620,000 | - | - | - | - |
| | $/Unit | $23,957 | $25,406 | $52,663 | $87,025 | $130,038 | $155,000 | - | - | - | - |
| Distribution Transformers | # of Units | - | - | 54 | 67 | 60 | 60 | 60 | 60 | 60 | 60 |
| | $ | - | - | $314,706 | $384,696 | $494,105 | $507,763 | $521,766 | $536,122 | $550,844 | $565,941 |
| | $/Unit | - | - | $5,828 | $5,742 | $8,235 | $8,463 | $8,696 | $8,935 | $9,181 | $9,432 |
| Switchgear Replacement Program | # of Units | 12 | 7 | 20 | 50 | 31 | 36 | 36 | 36 | 36 | 36 |
| | $ | $532,697 | $697,178 | $1,005,979 | $2,172,620 | $2,003,445 | $2,327,404 | $2,462,129 | $2,533,373 | $2,606,624 | $2,681,945 |
| | $/Unit | $44,391 | $99,597 | $50,299 | $43,452 | $64,627 | $64,650 | $68,392 | $70,371 | $72,406 | $74,498 |
| Mini-Rupter Switches | # of Units | - | - | - | 21 | 15 | 15 | 15 | 15 | 15 | 15 |
| | $ | - | - | - | $482,622 | $577,736 | $592,267 | $607,090 | $622,214 | $637,649 | $653,406 |
| | $/Unit | - | - | - | $22,982 | $38,516 | $39,484 | $40,473 | $41,481 | $42,510 | $43,560 |
| Automated Switches | # of Units | - | - | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| | $ | - | - | $392,480 | $380,627 | $435,912 | $447,130 | $458,595 | $470,301 | $482,308 | $494,628 |
| | $/Unit | - | - | $78,496 | $76,125 | $87,182 | $89,426 | $91,719 | $94,060 | $96,462 | $98,926 |
| Pole Replacement Program | # of Units | 117 | 315 | 368 | 453 | 400 | 400 | 400 | 400 | 400 | 400 |
| | $ | $1,200,000 | $4,320,000 | $5,341,485 | $4,948,885 | $4,645,383 | $4,933,143 | $5,570,700 | $5,870,246 | $6,241,483 | $6,244,377 |
| | $/Unit | $10,256 | $13,714 | $14,515 | $10,925 | $11,613 | $12,333 | $13,927 | $14,676 | $15,604 | $15,611 |

b) The number of asset units removed and to be removed will be the same as the number of units installed and to be installed in part (a).

c) Capitalized cost per asset units is shown in the table provided in part (a).

d) <u>Transformer and Municipal Station Circuit Breakers:</u>
Replacements are done over two years, with spending in the first year for engineering and long-lead materials. Cost per unit varies considerably due to diversity of equipment types, installation environment and scope of work.

<u>Underground Cable:</u>

The unit cost at each location is affected by the complexity of the location (residential, commercial, industrial, cable segment length, number of splices, drive way crossings, road crossing, number of Mini-Rupter switches, switching logistics, weather, etc.).This accounts for variances in unit cost for cable.

Submersible Transformers:
Unit cost at each location is affected by the complexity of the location (primary and secondary cable work required, new location to build new foundation for Padmount Transformer, drive way crossing, road crossing, turning curve, riser, weather, etc.). Project in 2015 and 2016 is a “Rocket ship” transformer replacement project in Barrie, which also includes the replacement of associated primary and secondary cables, which will make the unit cost to be higher.

Distribution Transformer:
The unit cost at each location is affected by the complexity of the location (primary and secondary cable work required, new location to build new foundation for the padmount transformer, etc.).

Switchgear:
Unit cost varies depending on equipment type and the complexity of the work at specific location.

**II-1-Staff-17**

**Ref: E G/T2/p. 2 l 3-7, Distribution System Plan Summary**

Average spending on System Renewal in the 2016-2020 period is planned to increase by 94% over 2011-2015 spending. PowerStream states "Renewal spending has increased due to the implementation of a comprehensive asset management process".

Please describe the new elements of the asset management process that were implemented in the past four years and had not existed prior to 2011 that have led to the 94% increase in System Renewal category.

**RESPONSE:**

Table 17 below, represents the Material Investment Projects for the System Renewal Category in 2011 to 2020.

PowerStream was formed by the merger of several utilities. PowerStream's first asset management plan was initiated in 2007 for transformer station assets.

PowerStream commenced the creation of its asset management plan for the distribution system in 2010 and started to implement and increase its asset renewal from 2010. The current level of investments for two major categories, cables and poles, reached a steady state in 2012. Over the years PowerStream has been developing asset condition assessment process and adding assets to the renewal program such as Mini-Rupter switch replacement, automated switch replacement and Station switchgear replacement.

The Storm Hardening work plan has been included in the asset replacement program following the 2013 Ice Storm.

**Table 17**

| | 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 Storm | 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** |

**II-1-Staff-18**

**Ref: E G/T2/ p. 3, l. 1-2, Distribution System Plan Summary, 5.3.1 Asset Management Process Overview, p. 12, 5.3.2 Overview of Assets Managed, Asset Inventory, p. 24 and EB-2013-0166, 2014 IRM - Response to SEC IRs, Appendix A: PowerStream Asset Condition Assessment Technical Report**

On page 3 of the DSP Summary, PowerStream states "All asset information used for Asset Condition Assessment and reliability analysis in the DS Plan is as of December 31, 2014".

In section 5.3.1 (page 12) of the Asset Management Process Overview PowerStream states that:

> The ACA program includes the development of Health Indices, risk-based economic analyses (probability of failure and criticality), and recommended Asset Sustainability Plans (replacements).

It is also stated that "asset condition assessment data is maintained, within the various asset registries, on the following key electrical distribution and general plant assets" with 17 categories then being listed.

a) Please confirm that Health Indices, risk-based economic analyses and recommended Asset Sustainability plans are completed on a cyclical basis (yearly or bi-yearly) for all the aforementioned assets to determine investment levels in the capital plan.

b) Please confirm that all Asset Condition Assessment results presented in the section Asset Inventory (beginning on p.24) are based on the asset registry and inspection data as of December 31, 2014.

c) What is the inspection year of the data used for the asset condition assessment? If variable between asset classes please provide what data is from which year. If varied between the units within the asset class, please provide a range of the earliest and latest inspection data used for the asset condition assessment for this asset class.

d) Did PowerStream update Risk-based economic analysis and Econometric replacement results in accordance with the ACA report provided in EB-2013-0166? If yes, please provide the results. If no, please explain.

e) Please explain how PowerStream used the risk-based economic analysis results in development and prioritization of the capital projects.

f) Has PowerStream changed any of the formulations, methodologies, useful lives, or probability failure curves between the revisions of the Asset Condition Assessment report (in 2009, 2012 and the most recent update presented in Asset Inventory)?

g) Please state whether or not the Asset Condition Assessment results presented in the Asset Inventory were the basis for the identification and development of investments proposed in the 2015-2020 DSP.

**RESPONSE:**

a) Asset Condition Assessment (ACA) was conducted for the following asset categories listed in Table 18a.

**Table 18a**

| | Health Indices (Yearly) | Risk-based Economic Analysis | Recommended Asset Sustainability Plan |
|---|---|---|---|
| Power Transformers (TS & MS) | Yes | Yes | Yes |
| Circuit Breakers (TS & MS) | Yes | Yes | Yes |
| Primary Switches (TS & MS) | Yes | Yes | Yes |
| 230kV Primary Metering Units | Yes | No | Yes |
| Station Reactors (TS) | Yes | Yes | Yes |
| Capacitor Banks (TS) | Yes | Yes | Yes |
| Station Service Transformers (TS) | Yes | No | Yes |
| P&C Relays (TS, line transformer and bus) | Yes | No | Yes |
| Distribution transformers | Yes | Yes | Yes |
| Distribution Switchgear | Yes | Yes | Yes |
| Mini-Rupter switches | Yes | No | Yes |
| Automated switches | Yes | No | Yes |
| Wood Poles | Yes | No | Yes |
| Underground primary Cable | Yes | No | Yes |

b) All Asset Condition Assessment results presented in the section Asset Inventory are based on the asset registry and inspection data as of December 31, 2014.

c) The inspection years of the data used for the asset condition assessment are shown in the Table 18c.

**Table 18c**

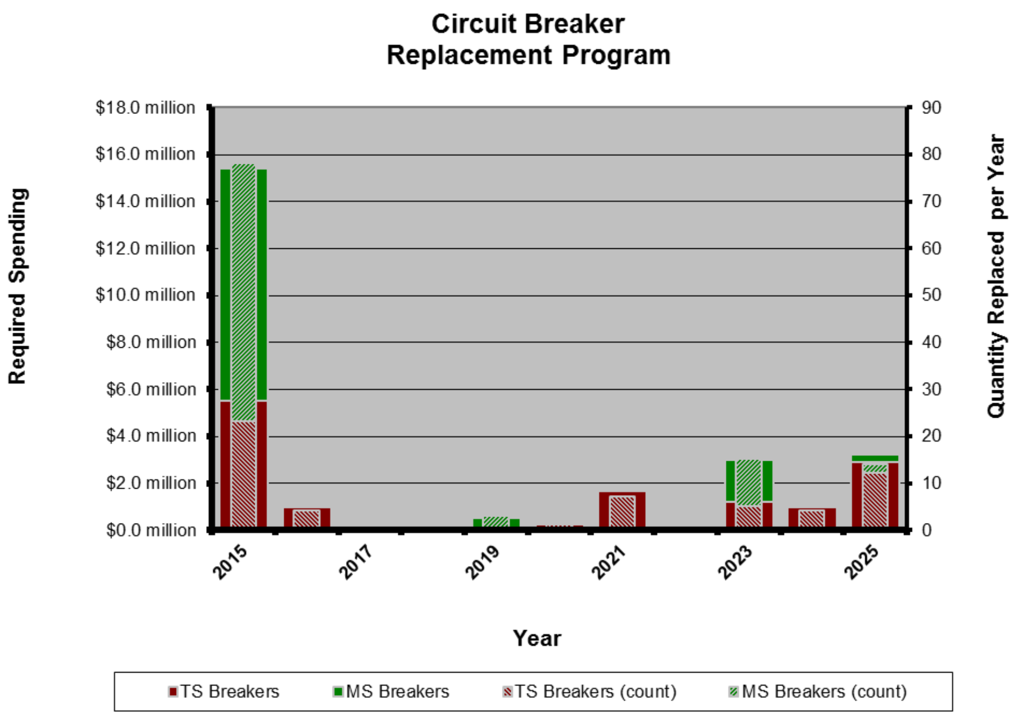
| | Inspection Year | Inspection cycle |
|---|---|---|
| Power Transformers (TS & MS) | 2014 | Yearly |
| Circuit Breakers (TS & MS) | 2014 | Yearly |
| Primary Switches (TS & MS) | 2014 | Yearly |
| 230kV Primary Metering Units | 2014 | Yearly |
| Station Reactors (TS) | 2014 | Yearly |
| Capacitor Banks (TS) | 2014 | Yearly |

| | | |
|---|---|---|
| Station Service Transformers (TS) | 2014 | Yearly |
| P&C Relays (TS, line transformer and bus) | 2014 | Yearly |
| Distribution transformers | 2012-2014 | 3 year cycle |
| Distribution Switchgear | 2012-2014 | 3 year cycle |
| Mini-Rupter switches | 2013-2014 | 3 year cycle |
| Automated switches | 2013-2014 | 6 year cycle |
| Wood Poles | 2010-2014 | 5 year cycle |
| Underground primary Cable | No inspection *Tested prior to cable prioritatization | No inspection |

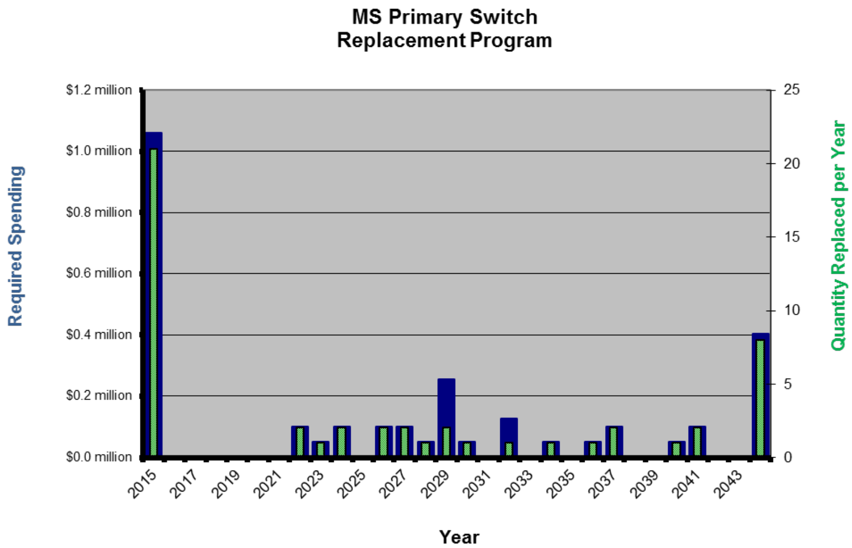
d) The updated Risk-based economic analysis and Econometric replacement results are summarized below.

Power Transformers, 230kV Primary Switches, and Station Reactors - The econometric model does not recommend any replacements within the next six years.

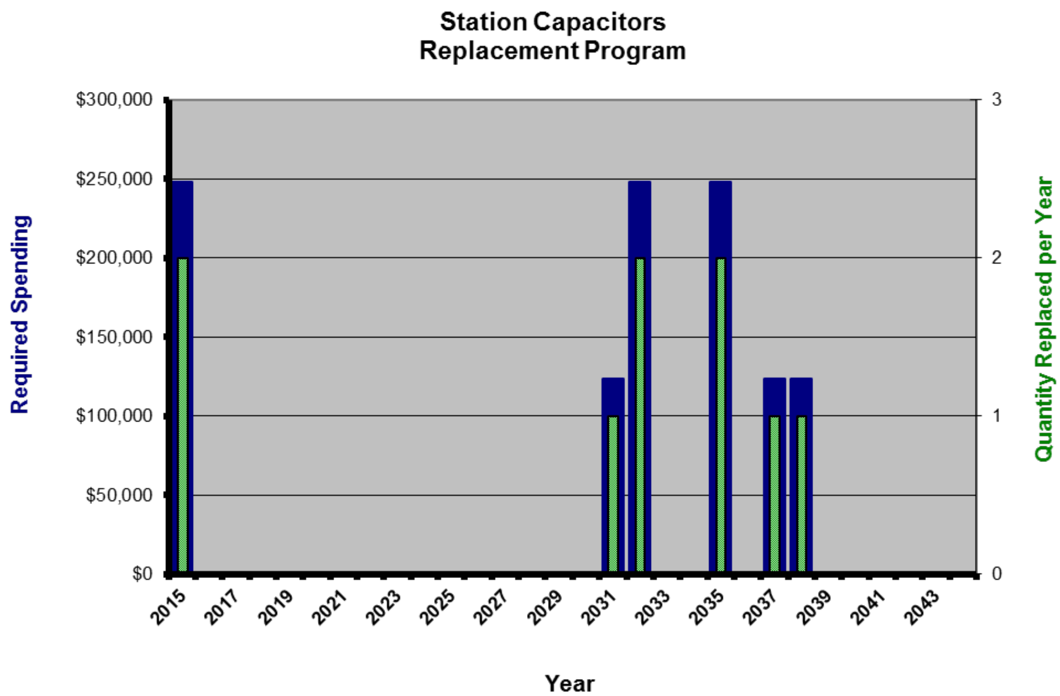
**Circuit Breakers**




**MS Primary Switches**

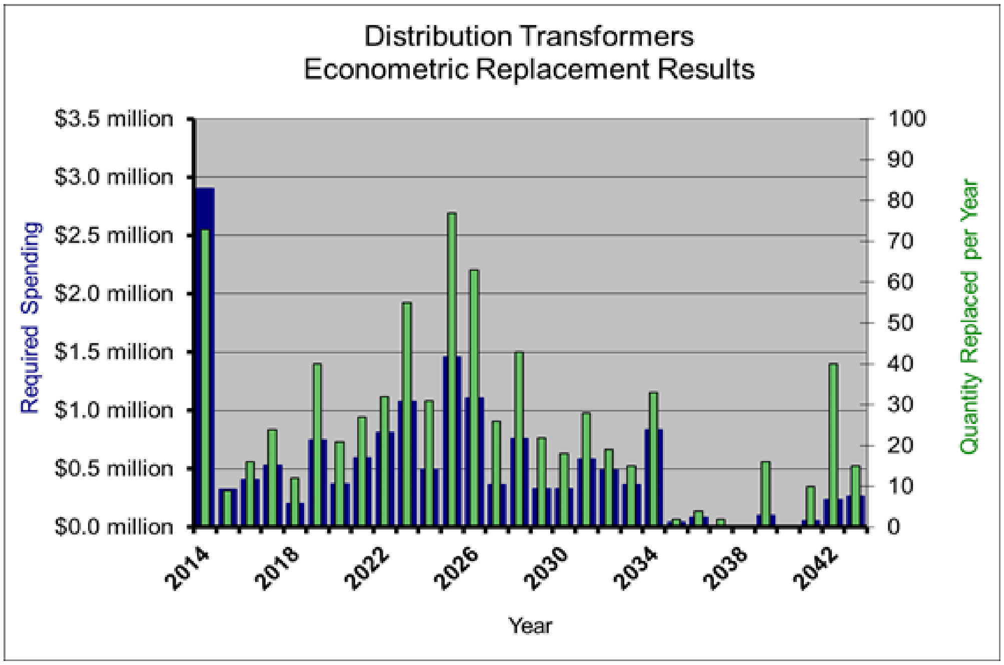



## Capacitor Banks

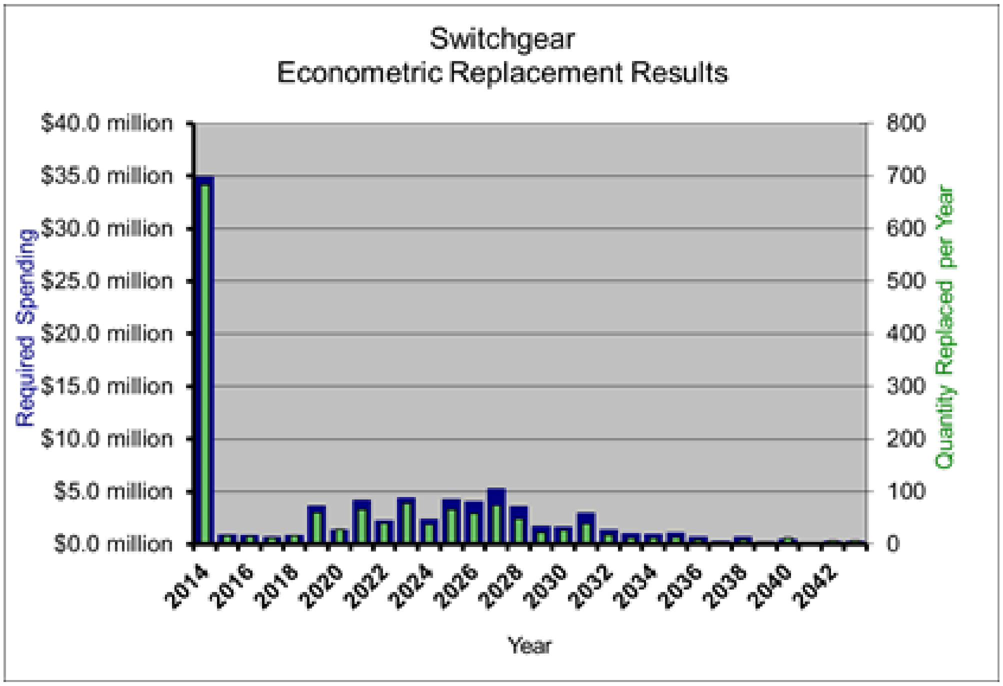



## Distribution Transformers

1


Distribution Transformers
Econometric Replacement Results
Required Spending
$3.5 million
$3.0 million
$2.5 million
$2.0 million
$1.5 million
$1.0 million
$0.5 million
$0.0 million
100
90
80
70
60
50
40
30
20
10
0
Quantity Replaced per Year
2014
2018
2022
2026
2030
2034
2038
2042
Year

**<u>Distribution Switchgear</u>**




<u>Mini-Rupter switches, Automated switches, Wood Poles and Underground primary Cable</u>

For these assets the ACA models do not have Econometric Replacement Results.

d) In developing and prioritizing of the capital projects, PowerStream incorporates engineering judgment and operations input with the econometric model results to prudently spread out the replacement programs over a longer period of time. The intent of spreading the replacement requirement over a number of years is to smooth out the budget, resource and rate impacts while managing the incremental risk of asset failure.

As a result of this approach, the annual numbers of replacement units proposed in the annual budget may be different from those “Econometric Replacement” numbers generated by the ACA models.

e) Changes to formulations, methodologies, useful lives or probability failure between the revisions of the Asset Condition Assessment Report (in 2009, 2012 and the most recent update presented in Asset Inventory) are summarized below.

- Failure curves were originally based on a Normal Distribution. In 2011 PowerStream worked with BIS Consulting to convert the failure curves from Normal to Weibull Distribution.
- Shape and Scale factors were adjusted in the Wood Pole Model to reflect

PowerStream's experience with wood poles. The 2009 version has Shape = 1.94 and Scale = 32.57. The 2012 version has Shape = 2.88 and Scale = 45.54.

f) Asset Condition Assessment results were the basis for the identification and development of investments proposed. The other factors that are used are operations requirements, safety concerns, obsolescence, customer service, and coordination with other internal and external capital work.

**II-1-Staff-19**

**Ref: E G/T3/p. 1**

At the above reference, it is stated that:

> In accordance with the Board's most recent Chapter 2 Filing Requirements for Distribution Rate Applications, dated July 18, 2014, at section 2.5.1.3, PowerStream continues to apply the 13% working capital allowance (WCA) factor to the sum of the Cost of Power and Controllable OM&A Expenses. The 13% WCA factor is applied throughout the five years in this application.

On June 3, 2015, the OEB issued a letter entitled "Allowance for Working Capital for Electricity Distribution Rate Applications" which provided an update to the OEB's policy for the calculation of the allowance for working capital for electricity rate applications. The letter stated that effective immediately the OEB was adopting a new default value of 7.5%.

The OEB further stated that for a Custom IR application it expected distributors choosing this option to file evidence in support of their requested working capital allowance, rather than the use of a default value. The letter also stated that while the use of the default value will no longer be applicable to Custom IR applications, given the timing of this new policy, distributors that have filed a Custom IR application for rates effective January 1, 2016 may use the 7.5% default value to calculate their working capital allowance rather than file a lead-lag study as part of their application.

a) Please state whether or not it is PowerStream's intention to file evidence in support of its proposed 13% working capital allowance, or to accept the 7.5% default value. If it is PowerStream's intention to file such evidence, please state the expected filing date.

b) In the event, PowerStream intends to request the 7.5% default value, please update its application to reflect all changes arising from the shift to a 7.5% default value.

**RESPONSE:**

a) PowerStream accepts the Board's default working capital allowance of 7.5%.

b) PowerStream has updated its application to reflect the 7.5% work capital allowance. This has reduced the rate base, revenue requirement and resulting rates.

**II-1-Staff-20**

**Ref: E H/T1/p.1.**

At the above reference it is stated that:

> In its Cost of Service Application (EB-2012-0161), PowerStream forecasted sales using a "top-down" approach…Striving for continuous improvement, PowerStream has since developed and is now proposing a new forecasting approach to load, customers and connections for this Application. The new approach developed in MetrixND, forecasts class-specific sales based on multifactor regression models.

a) Please state what factors caused PowerStream to conclude that it required a new forecasting approach and whether or not this was because any deficiencies were identified in the previous approach.

b) Please describe the process by which PowerStream determined what the new approach would be and why it believes it to be the best approach.

c) Please state whether or not PowerStream undertook any comparisons between the loads, customers and connections that would be produced by the two approaches and if so, please state what the results of these comparisons were. If PowerStream did not undertake any such comparisons, please explain why not.

**RESPONSE:**

a) In past forecasts, rate class sales forecasts were derived by proportionally allocating the purchase level forecast to rate classes based on rate class historical sales. The problem with this approach is that sales within each rate class are likely to increase at different rates over time; an allocation to rate classes based on historical usage would not necessarily reflect differences in customer class growth. We recognized the issue at the time, but did not feel that there was adequate historical billing data (given the first year of reasonable class data is January 2008) to estimate statistically strong class level sales forecast models. For the current forecast, we now have seven years of historical billing data allowing us to estimate reasonable rate class level sales forecast models. Given individual rate class responds differently to changes in weather, economic activity, and structural changes, models estimated with rate class sales data should result in more accurate rate class sales and customer forecasts.

b) During the course of developing the new forecasting approach, PowerStream evaluated a number of rate class sales and customer forecast models. Given the statistical strengths of the rate class models and reasonableness of the forecast results when compared with historical class sales, we believed that class-level sales forecast models provided more reasonable class sales forecasts than allocating the purchase level forecast based on historical class sales data. Please refer to III-H-Energy Probe-21 (c & d) and III –H-Energy Probe – 25 (b & c) for forecasting model evaluation.

c) Yes. Please see the comparison on the two forecasting approaches in the tables below.

**Table 1: Load Forecast Comparison (kWh)**

| Year | Sales - Specific Model | Purchase Model | Variance | Variance % |
|---|---|---|---|---|
| **2015** | 8,493,223,520 | 8,529,554,509 | - 36,330,989 | -0.4% |
| **2016** | 8,509,011,422 | 8,508,350,465 | 660,957 | 0.0% |
| **2017** | 8,485,564,197 | 8,486,142,373 | - 578,176 | 0.0% |
| **2018** | 8,462,668,700 | 8,441,657,440 | 21,011,260 | 0.2% |
| **2019** | 8,434,654,514 | 8,375,514,530 | 59,139,984 | 0.7% |
| **2020** | 8,411,546,941 | 8,307,822,644 | 103,724,297 | 1.2% |

**Table 2: Customer Counts Forecast – Prior Approach Using Historical Average Growth Ratio (Using 2011 to 2014 data)**

| Rate Class | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|
| **Residential** | 322,256 | 327,828 | 333,484 | 339,223 | 345,048 | 350,960 |
| **GS < 50** | 32,179 | 32,496 | 32,817 | 33,141 | 33,468 | 33,798 |
| **USL** | 2,928 | 2,967 | 3,006 | 3,045 | 3,085 | 3,126 |
| **GS > 50** | 4,841 | 4,893 | 4,946 | 4,999 | 5,053 | 5,107 |
| **Large User** | 2 | 2 | 2 | 2 | 2 | 2 |
| **Street Lighting Connections** | 87,732 | 89,509 | 91,323 | 93,173 | 95,061 | 96,986 |
| **Sentinel Lighting Customers** | 103 | 99 | 95 | 92 | 88 | 85 |
| **Street Light Customers** | 43 | 43 | 43 | 43 | 43 | 43 |
| **Total Customer Counts** | **362,352** | **368,328** | **374,392** | **380,545** | **386,787** | **393,121** |
| **Growth Ratio** | | 1.65% | 1.65% | 1.64% | 1.64% | 1.64% |

**Table 3: Customer Counts Forecast – Proposed Approach Using Regression Model**

| Rate Class | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|
| **Residential** | 322,324 | 327,907 | 333,673 | 339,480 | 345,362 | 351,406 |
| **GS < 50** | 32,228 | 32,594 | 32,973 | 33,354 | 33,739 | 34,134 |
| **USL** | 2,943 | 3,006 | 3,077 | 3,160 | 3,255 | 3,363 |
| **GS > 50** | 4,896 | 5,005 | 5,116 | 5,227 | 5,339 | 5,453 |
| **Large User** | 2 | 2 | 2 | 2 | 2 | 2 |
| **Street Lighting Connections** | 87,377 | 88,953 | 90,575 | 92,207 | 93,857 | 95,547 |
| **Sentinel Lighting Customers** | 107 | 106 | 106 | 106 | 106 | 106 |
| **Street Light Customers** | 43 | 43 | 43 | 43 | 43 | 43 |
| **Total Customer Counts** | **362,543** | **368,663** | **374,990** | **381,372** | **387,845** | **394,508** |
| **Growth Ratio** | | 1.69% | 1.72% | 1.70% | 1.70% | 1.72% |

**Table 4: Variance – Regression Model Approach Over Historical Average Growth Approach**

| Rate Class | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|
| **Residential** | 68 | 78 | 189 | 257 | 313 | 446 |
| **GS < 50** | 49 | 98 | 156 | 213 | 271 | 336 |
| **USL** | 15 | 39 | 71 | 115 | 170 | 237 |
| **GS > 50** | 55 | 113 | 171 | 228 | 286 | 347 |
| **Large User** | - | - | - | - | - | - |
| **Street Lighting Connections** | - 355 | - 556 | - 748 | - 966 | - 1,204 | - 1,439 |
| **Sentinel Lighting Customers** | 4 | 7 | 11 | 14 | 18 | 21 |
| **Street Light Customers** | - | - | - | - | - | - |
| **Total Customer Counts** | **191** | **335** | **598** | **828** | **1,058** | **1,386** |

**II-1-Staff-21**

**Ref: E H/T2/p. 3**

Please provide a table that lists all the appropriate OPA/IESO CDM Initiatives that produced net CDM savings which were used in the LRAMVA calculations. For each rate class, please list all relevant CDM initiatives in the applicable year and provide the subsequent net CDM savings for each. An example is provided below:

| Residential | Net kWh | Net kW |
|---|---|---|
| Initiative 1 | | |
| Initiative 2 | | |
| Initiative 3 | | |
| Total | | |
| Volumetric Rate Used | | |
| Lost Revenues | | |
| GS < 50 kW | Net kWh | Net kW |
| Initiative 1 | | |
| Initiative 2 | | |
| Initiative 3 | | |
| Total | | |
| Volumetric Rate Used | | |
| Lost Revenues | | |
| GS > 50 kW | Net kWh | Net kW |
| Initiative 1 | | |
| Initiative 2 | | |
| Initiative 3 | | |
| Total | | |

| | | |
|---|---|---|
| Volumetric Rate Used | | |
| Lost Revenues | | |
| Other classes (e.g., Streetlighting, Large Use, etc.), as needed | Net kWh | Net kW |
| Initiative 1 | | |
| Initiative 2 | | |
| Initiative 3 | | |
| Total | | |
| Volumetric Rate Used | | |
| Lost Revenues | | |

A separate table should be provided for each year.

**RESPONSE:**

Please refer to II-1-Staff-21 Appendix A for all CDM Initiatives by each rate class in the applicable year. To clarify, the CDM adjustment applied in the 2015-2020 load forecast will be the basis for LRAMVA calculation, if and when the actual CDM savings differ from this forecasted savings in the applicable year.

**II-1-Staff-22**

**Ref: E I/T1/p.1.**

At the above reference, PowerStream states when discussing Specific Service Charges states that it is not "proposing to alter the list or change the charges during the term of the Custom IR."

a) Please state when the existing specific service charges were first set.

b) Please state why PowerStream believes that it is reasonable to leave these charges unchanged for the five-year period of the application

**RESPONSE:**

a) PowerStream's specific service charges are based on the default amounts taken from the OEB 2006 Rate Handbook.

b) Please see the response to I-Energy Probe-30 and -Energy Probe-31 in the Application, Section III, Tab 1, page 254 ff. This subject is also discussed in the current interrogatory response to II-SIA-2 and II-SIA-3.

   Based on the analysis performed by PowerStream in response to Sustainable Infrastructure Alliance interrogatory II-SIA-3, it appears that the actual cost of providing the services covered by the specific service charges may be significantly greater than the costs recovered at the current rates. PowerStream believes that it would be reasonable to update these rates.

**II-1-Staff-23**

**Ref: E J/T1/p. 1**

Please state where in the above reference, PowerStream identifies its treatment of one-time costs in the application. If this treatment is not identified, please state what it is and what the typical amortization period would be.

**RESPONSE:**

PowerStream's has interpreted the question to relate to one-time costs that only occur in one period but are recoverable, specifically the regulatory costs associated with this Custom IR application. PowerStream is not proposing to amortize any incremental regulatory costs associated with this application.

**II-1-Staff-24**

**Ref: E J/T1/p. 2/Table 1**

At the above reference, PowerStream provides a year-by-year breakdown of its operating costs. The proposed increase in the 2016 Test year relative to the 2014 actual level is significant at 12.6%.

a) Please outline the outcomes and higher level of services that customers will receive for the relatively higher rates they are paying.

b) Please identify any customer engagement that supports the further increases proposed in this application.

c) Please provide the analysis that was performed to assess whether PowerStream's planning decisions reflect best practices of Ontario distributors.

d) Please identify any initiatives considered and/or undertaken by PowerStream, including any analysis conducted, to optimize plans and activities from a cost perspective, for example, balancing cost levels of OM&A versus capital.

e) The OEB's letter of August 14, 2014, established the stretch factor assignments for 2015 rates. PowerStream was assigned to Stretch Factor Group 3 out of five groups. Please provide details on any initiatives undertaken to improve PowerStream's assignment in future years.

**RESPONSE:**

a) Please refer to the response to II-Staff-8 that discusses outcomes.

There are two main drivers for the increase in OM&A in addition to the inflation and customer growth drivers.

The first is the higher level of costs associated with the new Oracle customer care and billing system ("CC&B"). CC&B has the ability to utilize new and emerging technologies to enable PowerStream to meet increasing billing and bill presentation requirements and growing customer expectations including those that provide real time engagement with customers advising them of predefined events or changes to account status. The new CC&B system provides customer service staff with better tools to address and resolve customer concerns at the time of the first call. In the longer term the new system is expected to provide better staff productivity.

The second is PowerStream's vegetation management program. This was initiated as a result of the 2013 ice storm which precipitated improvements to PowerStream's response to outages and emergency management protocols. These initiatives have provided valuable services to customers in the form of maintaining reliability and accessibility to information. The increase level of vegetation management will increase reliability and reduce outages.

The new CIS system and the increased vegetation management program are designed to address customers' concerns and preferences identified in the customer engagement activities: better communication, increased reliability and fewer outages.

b) PowerStream conducted a customer engagement exercise which followed the guidelines set out in the *Filing Requirements for Electricity Transmission and Distribution Applications, Chapter 5* which indicates that utilities must demonstrate that they have consulted customers on the Distribution System Plan in order to ensure that it responds to identified customer preferences. PowerStream therefore undertook a customer engagement exercise which focused on the Distribution System Plan and the capital spending identified therein.

c) PowerStream's planning decisions are made based on both a top-down and bottom-up approach. Business targets are set based on top-down analysis regarding financing and spending needs. Details are then developed based on PowerStream's plans for capacity, system replacements and operating and maintenance activities.

d) In order to optimize plans and activities from a cost perspective, operating and capital requirements and spend levels are always considered as a package when setting plans. The process for planning is separate for both but once the details are developed reconciliation between the top down targets and the bottom up details are reviewed collectively. Capital spending has an optimization process which identifies risks and benefits of doing projects. The OM&A budget target is set based on the historical 3 year actual indexed by 1% for inflation in order to try to keep costs as low as possible. A review of cost drivers and must do projects is discussed with the Budget Working Group in order to assess if the spend is necessary or if alternatives are possible. The balancing of OM&A versus capital is supported by PowerStream's capitalization policy ADM-48 which was filed as part of the Rate Application, Section VI, Tab 18, Sch. 1.

e) PowerStream's productivity initiatives are discussed in the Application in Section II, Tab 1, Exhibit F, Tab 1.

**II-1-Staff-25**

**Ref: E J/T2**

At the above reference, PowerStream discusses its approach to compensation.

a) PowerStream does not appear to have undertaken any relevant studies of its proposed increases in compensation/headcount on the basis of compensation benchmarking, or any other external comparators, and appears to have justified its proposed increases solely on the basis of its anticipated needs without any specific reference to any external comparators. Please explain what analyses and data PowerStream has used to derive its proposed compensation per headcount for the bridge and test years.

b) With respect to Appendix 2-K, please explain PowerStream's compensation strategy. Please explain how this strategy has resulted in an 11% increase in management and 4% increase in non-management compensation for the 2016 Test year as compared to 2014 actuals.

**RESPONSE:**

a) PowerStream determines the overall annual base salary increase (merit increase) percentage through a combination of the organization's overall performance and market conditions.

In 2014 PowerStream participated in the MEARIE Group Salary Survey. The Mearie Group established the Management Salary Survey of Ontario's Local Distribution Companies. The objective was to understand the competitive landscape and to support PowerStream's efforts in maintaining pay practices that attract, motivate and retain high quality, high performing employees. The Survey was conducted in Partnership with the Hay Group, a globally established and renowned compensation consulting firm.

The Salary Survey data included:

- Geographic, Number of Employees, Number of Customers and Revenue size reporting.
- Fifty (50) benchmark descriptions, supported by the Hay Group job evaluation methodology
- Reporting of Total Cash Compensation
- Local distribution company market trends and compensation projections for budget planning and forecasting.

The Salary Survey and the Conference Board of Canada Compensation Planning Outlook 2015 were used for compensation and budget planning in the bridge and test years.

b) The compensation philosophy for PowerStream is based on a commitment to hire and retain qualified, motivated employees at all levels within the organization while meeting the needs of the Company. This philosophy is the foundation of our compensation system and is designed to support the successful attainment of our vision, mission, values, and business objectives.

PowerStream aspires to support its values through a compensation program that provides:

- Competitive salary ranges to enable the recruitment and retention of qualified employees.
- A performance planning and common review process that works to develop the abilities of each employee and provide the feedback necessary to ensure their success.
- Administrative systems that are designed to systematically and equitably manage pay on a Company-wide basis, yet allow the flexibility needed to be effective in a dynamic and ever changing environment.
- Communications that will support a general understanding of compensation programs throughout the Utility.

The 11% increase in management compensation from 2014 actual to 2016 represents the total dollar increase which reflects an increase in FTE in the management group. The 4% increase to the total dollar compensation in the non-management group reflects an increase in FTE offset by a reduction in temporary staff.

**II-1-Staff-26**

**Ref: E J/T2/p.2 and J-SEC-34 SIII/T1/S1/pp.305-306.**

At the first reference above, PowerStream provides Appendix 2-K Employee Costs.

At the second reference, PowerStream is requested to add two lines to the above referenced appendix "Total Compensation Charged to OM&A" and "Total Compensation Capitalized."

Please provide an explanation for the changes in "Total Compensation Charged to OM&A" particularly including an explanation as to why this amount on a percentage basis appears to be lower for 2014 Actual than for the prior or subsequent years.

**RESPONSE:**

The 2014 total compensation charged to OM&A is lower than subsequent and prior years as a result of a number of staff working on more capital projects in 2014. This decreased the percentage of total compensation charged to OM&A to 63% as compared to 66% in the prior year and increased the amount of compensation charged to capital from 34% in 2013 to 37% in 2014 as a result of the CIS project.

**II-1-Staff-27**

**Ref: E L/T1**

At the above reference PowerStream's approach to cost allocation is discussed.

On June 12, 2015, the OEB issued a new cost allocation policy for the streetlighting rate class.

a) Please confirm that the current application as filed does not incorporate any updates to reflect the new OEB policy, or if it does, please explain.

b) If the application as filed does not incorporate the new policy, please state whether or not PowerStream has any plans to update the application for this change and if so what the timing of such an update would be.

**RESPONSE:**

a) PowerStream confirms that the current application, as filed, does not incorporate any updates to reflect the New Cost Allocation Policy for Street Lighting Rate Class (EB-2012-0383).

b) PowerStream has updated the application to reflect the New Cost Allocation Policy for Street Lighting Rate Class. Updated costs allocation models for test years 2016-2020 are presented in Section C; Appendices, Section 1, Tab 1, II-1-Staff 27, Appendix A to E.

**II-1-Staff-28**

**Ref: E M/T1/p.4.**

At the above reference it is stated that:

> PowerStream notes that the OEB is currently undergoing a process to review rate design for the Residential and small General Service classes (EB-2012-0410). PowerStream has not incorporated any of the rate designs as outlined in the Draft Report of the Board at this time. However, should the OEB issue direction to LDCs related to this consultation, PowerStream is prepared to incorporate changes as applicable.

On April 2, 2015, the OEB issued its EB-2012-0410 *Board Policy A New Distribution Rate Design for Residential Electricity Customers.* In this document, it is stated that "Under the new policy, electricity distributors will structure residential rates so that all the costs for distribution service are collected through a fixed monthly charge."

a) Please confirm that the current application as filed does not incorporate any updates to reflect the new OEB policy, or if it does, please explain.

b) If the application as filed does not incorporate the new policy, please state whether or not PowerStream intends to file for an exception request or has any plans to update the application for this change and if so what the timing of such an update would be.

**RESPONSE:**

a) PowerStream confirms that the current application, as filed, does not incorporate any updates to reflect the Board Policy on the *New Distribution Rate Design for Residential Electricity Customers* (EB-2012-0410).

b) In response to this interrogatory PowerStream has updated the application. PowerStream has applied the fixed-variable rate design for Residential rate classification in accordance with the Board's letter from July 16, 2015 on *"Implementing a New Rate Design for Electricity Distributors (OEB File No. EB-2012-0410)".* Please refer to Section A, Application Update Summary, for the Fixed/Variable Rate Design.

**II-1-Staff-29**

**Ref: E M/T3/p. 1**

At the above reference, PowerStream discusses its 2016 to 2020 proposed RTSRs.

On January 8, 2015 (EB-2014-0357), the OEB issued a Rate Order for the 2015 Uniform Transmission Rates and on April 23, 2015 (EB-2013-0416), the OEB issued a Rate Order for Hydro One Distribution's Sub-transmission rates.

Please provide an updated RTSR Adjustment Workform in working Microsoft Excel format reflecting the new UTR's and Sub-Transmission Rates, as applicable, including any other corrections or adjustments that PowerStream wishes to make to the previous version of the Workform. Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or an explanatory note.

**RESPONSE:**

Please refer to II-1-Staff-29-Appendix B for updated RTSR Excel workbook. This update reflects the following changes:

- Uniform Transmission Rates: Rate Order issued by OEB on January 8, 2015;

- Hydro One Distribution's Sub-transmission Rates: Rate Order issued by OEB on April 23, 2015;

- RPP and non-RPP price: Regulated Price Plan Price Report issued on April 20, 2015 by OEB;

- 2015 Forecast Billing Determinants: Based on updated load forecast as per III-VECC -19 (c); and

- 2016-2020 Forecast Billing Determinants: Based on updated load forecast as per III-VECC -19 (c)

**II-1-Staff-30**

**Ref: E N/T1/S1/p. 1**

At the above reference, PowerStream discusses its OPEB Deferral Account.

PowerStream has recovered OPEBs in rates previously.

a) Please indicate if OPEBs were recovered on a cash or accrual accounting basis for each year since PowerStream started to recover OPEBs.

b) Please complete the table below to show the difference, if any, between the actual cash benefit payments and the amounts recovered from ratepayers from the year PowerStream started recovering amounts for OPEBs.

| **OPEBs** | **First year of recovery to 2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **Total** |
|---|---|---|---|---|---|---|---|
| Amounts included in rates | | | | | | | |
| OM&A | | | | | | | |
| Capital | | | | | | | |
| Sub-total | | | | | | | |
| Paid benefit amounts | | | | | | | |
| Net excess amount included in rates greater than amounts actually paid | | | | | | | |

c) Please describe what PowerStream has done with any recoveries in excess of cash benefit payments.

**RESPONSE:**

a) PowerStream cannot provide the information requested within the schedule for interrogatory responses. This time period in the table pre-dates the first rate case of the amalgamated company resulting from the PowerStream merger with Barrie Hydro Distribution Limited (EB-2012-0161). In its 2013 rate application and the current Application, PowerStream has used the accrual method.

b) PowerStream has provided the available data in Table II-1-Staff-30-1 below.

**Table II-1-Staff-30-1: OPEB Data ($ thousands)**

| | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|
| **(A) Expense per Financial Statements on an accrual basis:** | **$1,897** | **$1,824** | **N/A** | **N/A** |
| **Amounts included in rates:** | | | | |
| **OM&A** | **$1,198** | **$1,198** | **$1,198** | **$875** |
| **Capital** | **$617** | **$617** | **$617** | **$451** |
| **(B) Total in rates** | **$1,815** | **$1,815** | **$1,815** | **$1,326** |
| **(C) Amounts paid** | **$628** | **$299** | **N/A** | **N/A** |
| **Variance (B-C)** | **$1,187** | **$1,516** | | |

N\A – not available

The amount included in rates for the 2013 Cost of Service was the 2013 budgeted OPEB cost. Rates for 2014 and 2015 are based on the 2013 amount. The amount shown for Rates in 2016 represents the budgeted OPEB cost included in this Application.

c) Amounts recovered in rates in excess of cash benefits paid for OPEB are part of the funds retained in the business.

**II-1-Staff-31**

**Ref: E N/T3/p.1**

At the above reference, it is stated that PowerStream is requesting a new deferral account to capture the net book value of meters removed from service to comply with the OEB's May 21, 2014 Distribution System Code amendment requiring all General Service over 50 kW customers to have meters capable of recording time-of-use electricity consumption.

Please provide a draft accounting order for the proposed deferral account.

**RESPONSE:**

A draft accounting order should no longer be required as the Board has issued a new deferral account "1557" per the March 2015 accounting guidelines. Item #3 in this document describes the accounting treatment for Meters Inside the Settlement Timeframe ("MIST") and other incremental costs. The net book value of the removed meters would be recorded in this account. Below is the description from the guideline:

"With this March 2015 guidance, Account 1557 Meter Cost Deferral Account has been established for the tracking of incremental capital and OM&A costs. Distributors should open sub-accounts to segregate capital from OM&A and carrying charges to facilitate applications for disposition of the amounts. Distributors should be guided by the various Board documents related to record-keeping and disposition of smart meter costs. Chapter 2 of the *Filing Requirements for Electricity Distribution Rate Applications* dated July 18, 2014 contains the materiality thresholds in section 2.4.5."

**II-2-Staff-32**

**Ref: E G/T2**

The above reference is PowerStream's Consolidated Distribution System Plan.

Chapter 5 of the Filing Requirements states, "A DS Plan filing must demonstrate that distribution services are provided in a manner that responds to identified customer preferences."

Please explain how PowerStream's DS Plan reflects customer preferences identified through customer engagement.

**RESPONSE:**

PowerStream's experience with engaging customers on the development of options for the DS Plan was that significant time and effort was required to educate customers on the distributions System and the electricity system in general. Due to the high level of electricity literacy required for customers to be able to provide meaningful feedback on specific plans and projects proposed in the DS Plan, customers frequently felt that they did not know enough to be able to make conclusions regarding the operational and capital spending decisions made by the utility. For example, it was found that 58 per cent of those consulted felt that PowerStream's investment plan was heading in the right direction. A further 35 per cent were unsure, or felt that they did not have enough information or knowledge of the electricity system or of PowerStream to make a determination.

PowerStream valued the input that was received from customers as it confirmed the level of general support customers have for PowerStream's plans and approach to investment. Given the level of acceptance PowerStream received from a representative and statistically significant sample of its customers, the utility did not feel it necessary to deviate from its initial plan balanced reliability and costs among our customers.

**II-2-Staff-33**

**Ref: E G/T2, 5.2.1 Distribution System Plan Overview/ p. 1, l. 27-29**

PowerStream states:

> These corporate objectives influence the DS Plan. They are used within the optimization scoring process to link value to the strategy map and they are tied to business cases.

Please show the score value assigned to each objective using a few typical individual projects.

**RESPONSE:**

Refer to Appendix Staff 51g.

**II-2-Staff-34**

**Ref: E G/T2/ 5.2.3 Performance Measurement for Continuous Improvement, p. 4, l. 2-9**

PowerStream states that its plan execution metric is actual capital spending compared to the approved capital budget. Although no previous DSP has been filed yearly spend as compared to planned should be available year over year.

a) Please provide previous plans for the yearly spend as defined.

b) Please complete the table below for the historical five year period for planned vs actual capital spend.

| | 2011 | 2012 | 2013 | 2014 | 2015 (YTD) |
|---|---|---|---|---|---|
| Planned | | | | | |
| Actual | | | | | |
| Deviation ($) | | | | | |
| Deviation (%) | | | | | |

**RESPONSE:**

a) Refer to the Corporate 5 and 10 Year Capital Plans completed in 2011, 2012, and 2013 submitted as Appendices Staff 34.1, Staff 34.2 and Staff 34.3. It should be noted that the Corporate 5 and 10 year plans have not been optimized unlike the DS Plan.

b) Refer to Table 34b below.

**Table 34b**

| (000's) | 2011 | 2012 | 2013 | 2014 | 2015 (YTD) |
|---|---|---|---|---|---|
| **Planned** | 69,731 | 76,685 | 111,984 | 108,238 | 118,400 |
| **Actual** | 63,297 | 74,832 | 93,657 | 109,509 | 45,107 |
| **Deviation ($)** | - 6,434 | - 1,853 | - 18,326 | 1,271 | - 73,293 |
| **Deviation (%)** | -9% | -2% | -16% | 1% | -62% |

Note: 2015 YTD shown is for the period ending June 30th

**II-2-Staff-35**

**Ref: E G/T2, 5.2.3 Performance Measurement for Continuous Improvement, p. 4, l. 11-24 and p. 5, Figure 2**

PowerStream states that it:

> … will be monitoring its execution of the projects and programs included in the DS Plan. Variances, which are defined as a comparison of the actual dollars spent compared to the approved budget estimate, are reviewed are categorizing within the prescribed limits.

a) Please comment on whether or not there is a lack of management of work order variances as illustrated through the inconsistency of work order variances in Figure 2.

b) How is the "budget estimate" related to the OEB approved spending?

c) When did PowerStream last refine labour/equipment rates and standard labour/equipment hour allocations for its unit costs used in estimates?

d) Please state whether or not PowerStream has performed an analysis as to whether or not labour/equipment rates and their allocation reflect actual costs of 2016. If yes, please provide the results.

e) Please provide an overview of the major causes of variances of work orders by percentage contribution to overall variances for each historical year (2011-2015 [YTD]).

**RESPONSE:**

a) In Figure 2, DSP Section 5.2.3, the ***monthly*** "Percent of Work Orders Completed Within Variance" number should not be used to determine whether or not work order variances are improving. It is the year-end number for comparing year-to-year performance that is more accurate and useful. Each month, the work orders that are closed and reviewed for variance analysis are a mix of small dollar work orders and large dollar work orders, short duration projects and long duration jobs, current year jobs and previous year jobs. Month-to-month changes in the variance percentages are not indicative of a general trend in work order management.

b) The "budget estimate" referred to E G/T2, 5.2.3 Performance Measurement for Continuous Improvement, p. 4, l.11-24, is the budget estimate for a project. The sum total of all the individual project budgets and programs is used to determine the overall PowerStream corporate budget for the OEB Rate Application.

c) PowerStream updates its labour & equipment rates yearly; the last update was made in 2014.

Prior to 2015, PowerStream used the industry standard Ontario Hydro developed labour & equipment hour estimates. Starting in 2015, PowerStream has introduced its own PowerStream developed "labour kits" for the hour allocations used in unit cost estimates for work not covered by Ontario Hydro estimates.

d) PowerStream is unable to provide labor equipment rates and their allocation that reflects actual costs of 2016.

e) The major causes of variances of work orders are labor, material, contract/consulting, and other. The net dollar amount of the variances for those causes, by year, is shown in Table 35e below. To calculate a meaningful percentage contribution of each cause it is necessary to use the total absolute value of the individual causes for the yearly total.

**Table 35e**

| Year | Net Sum of Labour Variances | Net Sum of Material Variance | Net Sum of Contract/Consulting Variance | Net Sum of Other Variance | | Total Absolute Value of Variances |
|---|---|---|---|---|---|---|
| 2013 Total | -$ 1,620,564 | -$ 807,908 | $ 818,023 | -$ 367,697 | | $ 3,614,192 |
| 2014 Total | -$ 5,163,950 | -$ 2,048,404 | $ 1,109,256 | -$ 1,345,795 | | $ 9,667,405 |
| 2015 YTD | -$ 2,195,501 | -$ 1,449,685 | $ 4,044,529 | -$ 525,337 | | $ 8,215,052 |
| | | | | | | |
| Year | Labour Variance to Total | Material Variance to Total | Contract/Consulting Variance to Total | Other Variance to Total | | |
| 2013 Total | 44.8% | 22.4% | 22.6% | 10.2% | | |
| 2014 Total | 53.4% | 21.2% | 11.5% | 13.9% | | |
| 2015 YTD | 26.7% | 17.6% | 49.2% | 6.4% | | |

*Caution* This table cannot be tied back to original budget estimates in a meaningful manner as the variance analysis is based at a specific work order level which does not tie back to the budget level.

**II-2-Staff-36**

**Ref: E G/T2, 5.2.3 Performance Measurement for Continuous Improvement, p. 5, l. 6-7**

PowerStream states that "Cable remediation is the only program where failure rate analysis can be readily measured."

Please state why failure rate data is not readily available for other asset classes.

**RESPONSE:**

The intent of the statement (*cable remediation is the only program where failure rate analysis can be readily measured*) was to qualify the measurement to a specific project within a program, as compared to an overall asset class program.

Cable remediation includes cable replacement and cable injection at specific locations that have specific failure rates. Once remediation has been performed, pre and post remediation statistics are readily available.

Failure rate data is available for other asset classes, however, the failure rate comparison pre and post remediation cannot be measured for the other assets as they are system wide, and not location specific. Please refer to G-AMPCO-6 (J) for further information.

At the overall system level, the failure rate for each asset class is available.

**II-2-Staff-37**

**Ref: E G/T2, 5.2.3 Performance Measurement for Continuous Improvement, p. 12, l. 1-9 and EB-2013-0166, 2014 IRM – Response to SEC IRs, Appendix A: PowerStream Asset Condition Assessment Technical Report, p.5**

PowerStream states at the first reference that:

> The Health Index for distribution assets identifies the current level and future risk of equipment failure …The Health Index metric is also used to provide an indication of the level of investment required over a twenty year planning horizon…

a) Please describe how PowerStream uses the health index score to gather indications of appropriate levels of investment. Please provide the step by step procedure from health index score to investment level.

b) What is the rationale behind the twenty-year planning horizon selected?

**RESPONSE:**

a) The SEC IRs, Appendix A: PowerStream Asset Condition Assessment Technical Report, pages 5-9, outlines the Asset Condition Assessment Framework. The document describes how the health indices are formulated and applied to various asset classes. It further describes what assets need remediation. Once identified, the projects are then submitted to the asset management process, as outlined in the DS Plan, Section 5.3.1.

b) The Asset Condition Assessment models produce the results for up to 120 years out. For readability, the charts showing recommended program spending are truncated at year 20. PowerStream selected a twenty-year planning horizon to evaluate the sustainability of the distribution system in the longer term. On an annual basis, PowerStream assesses the current and future annual investment levels to determine if they are sufficient to address the aging asset needs. Additionally, PowerStream can determine if the asset replacements identified were to be deferred, what level of funding and resources would be required in the future to renew the asset base.

**II-2-Staff-38**

**Ref: E G/T2, 5.3.1 Asset Management Process Overview, p. 27, l. 7-8**

PowerStream states that business cases used to support a request for capital funding must contain among other requirements "financial details associated with each alternative; and financial analysis to capture both capital and OM&A".

a) Please describe the financial details that must be included with each alternative.

b) Please confirm that the financial analysis is intended to capture the Net Present Value of the respective projects. If yes, please provide the methodology used by PowerStream to calculate Net Present Value. If no, please explain the financial metrics used by PowerStream to determine cost savings benefits over the costs of the projects.

**RESPONSE:**

a) The financial details that must be included with the recommended alternative are the total dollars required in each year of that project. These are provided within the system by general ledger breakdown.

b) The financial analysis provided in the business cases, that were used in the rate submission, took into consideration both capital and OM&A costs and savings to determine the "Value" of a project. It did not calculate a "Net Present Value".

The financial metrics presently used by PowerStream to determine costs savings benefits over the costs of the projects are as follows:

i) Capital Financial Benefits
- Expected Reductions
- Avoided Cost
- Efficiency Benefit

ii) OM&A Financial Benefits
- Expected Reductions
- Avoided Cost
- Efficiency Benefit

**II-2-Staff-39**

**Ref: E G/T2, 5.3.2 Overview of Assets Managed, p. 5, Figure 2 and Section VI, T13/S1/p. 3**

In the first reference, projected peak load in PowerStream South in 2021 is 1,966MW compared to 1,689MW in 2016. This growth is about 16% over the five year period. Overall growth for the previous five year period 2011-2016 is only 3%.

In the second reference, PowerStream indicates in “Schedules of Volumes, Customers/Connections and Revenues” that while customer count will increase by approximately 1.8% a year, consumption in kWh will decrease approximately 1% a year with Total KW Volumes in 2020 decreasing by 1% compared to 2016.

a) Please provide the basis for such a rapid anticipated growth in PowerStream South in 2016-2021. Please provide any study or report that would justify the projected 16% increase in the 2016 to 2021 period.

b) Please provide the actual peak load in 2014, and 2015YTD.

c) Please provide similar projections of Peak load in PowerStream North.

d) PowerStream calculates 2016-2020 rates based on decreasing consumption by its customers and a modest increase in customer counts. However, the DSP is based on the projected rapid growth of the system peak. Please explain.

e) Please provide a forecast of the system peak by 2020 with a confidence interval (min/max), year-by-year, for South and North.

f) Please describe the conservation measures committed and planned to reduce peak demands in PowerStream’s service territories.

**RESPONSE:**

a) The load forecast was prepared in 2013 based on York Region’s population, household and employment forecast for 2031. Refer to the Appendix Staff-39a.1 York Region Population and Employment Forecast Report, and Appendix Staff 15c.1, PowerStream South Load Forecast 2-15-2014 Rev.4.

b) The actual peak in 2013 was 1,633 MW for PowerStream South.

The actual peak in 2014 was 1,391 MW for PowerStream South (the weather of summer 2014 was cooler than normal. There were no days where the “weighted 3- day” average temperature was over 30°C in the summer. It was the seventh coolest summer in the last 40 year period).

The actual peak in 2015 so far is 1,474 MW for PowerStream South.

c) The actual peak in 2013 was 340 MW for PowerStream North.

The actual peak in 2014 was 303 MW for PowerStream North (the weather of summer 2014 was cooler than normal. There were no days where the "weighted 3- day" average temperature was over 30°C in the summer. It was the seventh coolest summer in the last 40 year period).

The actual peak in 2015 so far is 318 MW for PowerStream North.

d) The electrical distribution system is planned to deliver load to customers at peak times, and the system must meet the highest capacity demand under the most difficult thermal constraints (a 1-in-10 hot weather scenario). System peak is at a single point in time.

The load forecast, used to forecast billing determinants, is a measure of forecasted energy consumption over the entire period. The load forecast is weather normalized and based on the expected energy volume.

Consumption per customer is declining but this does not mean that the system peak is.

PowerStream continues to review the load forecast methodology and results in light of Conservation, Demand Management, Distributed Generation and/or other initiatives that may lead to declines or increases in capacity requirements.

e) As outlined in Appendix Staff 39a.2, PowerStream South Load Forecast 2-15-2014 Rev.4., PowerStream has adopted an End Use Analysis method in the load forecast by using latest information gathered from the municipalities and other related agencies. The load forecast matrix takes into account growth rates, price impact, CDM and weather scenarios. The trend analysis with ±2.5% confidence is used as reference only.

f) In the new 2015-2020 framework, according to the Minister's directive, targets are based on energy savings, which is unlike the previous framework where there was both a demand target and an energy target. PowerStream's target is to achieve 535 GWh in energy savings by 2020.

PowerStream CDM Plan is posted at the IESO website:

http://www.ieso.ca/Documents/conservation/CDM-plans/CDM-Plan-201412180060-PowerStream-COLLUS-v1-3.pdf

In the process of achieving the target energy savings, the plan will also contribute towards peak demand reductions. It is estimated that by implementing the CDM plan, PowerStream will realize 65 MW of net peak demand savings by 2020.

**II-2-Staff-40**

**Ref: E G/T2, 5.3.2 Overview of Assets Managed, p. 18, l. 12-15**

PowerStream states that its system planning philosophy for municipal sub-stations in the north requires:

> … a "triad" model of supply – where at least three stations (or 3 transformers) are tied together through open points such that loss if one station is lost, all load from the triad supplied stations can be supplied by the remaining stations. This criteria considers individual substation transformer ratings as well as the network's contingency capacity.

Please state whether or not PowerStream has performed a risk-based economic or any other type of business analysis to justify this philosophy versus other models of supply. If yes, please provide the report.

**RESPONSE:**

PowerStream follows a deterministic planning philosophy which is consistent with utility practice across Canada. A deterministic approach requires that supply is maintained during any N-1 contingency conditions. This requirement extends itself to the "Triad" model of supply prescribed by PowerStream to ensure that loss of a single substation transformer can be supported by surrounding substation transformers. The "Triad" configuration ensures that upon loss of a single substation transformer the two remaining transformers can accommodate the transferred load in addition to their own native load, thereby mitigating any potential load shedding as a result of the outage. The "Triad" configuration lends itself to either a network of electrically isolated substations, or to an interconnected network of substations constrained by feeder connections with transfers limited by thermal limits or nominal voltage thresholds.

PowerStream performs a risk-based analysis in cases where a project identified through the deterministic planning philosophy requires deferment. PowerStream's risk based analysis considers an asset's age, health index, near-term failure probability, and failure of probability based on age and health index. Asset condition information and probability of failure is combined with historical loading data and system constraints such as thermal limits and nominal voltage thresholds to identify potential deferment options and the respective risk associated with each option. In addition to the risk based analysis, PowerStream also generates an econometric model that considers the magnitude of load at risk above N-1 and the respective value of the load at risk. The econometric model considers the amount of load at risk during contingency conditions, the probability of failure, the frequency of a potential outage based on historical data, the duration of the outage, and the outage cost per kWh based on historical customer generated data.

Refer to Appendix Staff 40 Risk Assessment for Deferring Harvie MS and of an econometric model for the risk associated with deferring a new substation in Tottenham.

**II-2-Staff-41**

**Ref: E G/T2, 5.3.3 Asset Lifecycle Optimization Policies and Procedures, p. 1, l. 29-32, p. 2, l. 1-12 and p. 3, Figure 1**

At the first reference, PowerStream states:

> A large contributor to the assessment process is the annual inspection of critical assets. Annual inspections are completed on the distribution system for the overhead system, load interruptor switches, padmount switchgear, vault rooms, padmounted switchgear, stations and poles. An assessment is made and an asset will be categorized as a Code A, Code C, or Code C…

PowerStream goes on to describe the actions required for each code inspection.

a) Please state why the code system has been developed and how it adds value beyond the established methodology used in ACA.

b) Please provide the justification, for each critical asset class, by which the prescribed actions for each code have been determined. Please state how this optimal policy has been determined.

c) In Figure 1, for categories where the Health index is not applicable, please confirm that it is not used in the identification or justification for asset investment.

d) In Figure 1, for categories where the prioritization score is not applicable, please confirm that no prioritization is done for these assets.

e) In Figure 1, where both Health Index and Inspection is present for an asset class:

   i. please outline the way in which each is used in the determination of investment (i.e. where is there overlap between the two, which takes priority, how each influences decisions etc.)

   ii. if the inspection assigns Code C to the asset, but the Health Index shows a Poor condition, please state which is determinative.

**RESPONSE:**

a) Appendix C (Table-1) of the Distribution System Code (DSC) sets out minimum inspection requirements for the distribution system and requires that any detected deficiencies are reported and corrected. In addition to the OEB requirements, PowerStream is obligated by ESA Reg 22/04, Section 4 to inspect and maintain the equipment in proper operating condition. In order to ensure compliance with both OEB and ESA inspection and maintenance requirements, PowerStream has an annual Inspection and Maintenance program. The Inspection and Maintenance program assigns a code based on the condition of the asset which assists in the determination of corrective action.

PowerStream extensively uses asset condition information derived from the inspection and maintenance program to feed the ACA models. The Health Index calculation uses the condition assessment obtained during the inspection for each asset as outlined depending on the asset.

b) The codes were determined through the development of PowerStream's Inspection and Maintenance procedures.

Each asset class code was established by PowerStream based on input from engineering, lines, field inspectors, subject matter experts and manufacturers. The optimal policy is determined by a periodic review of the procedures by the Asset Management Committee.

c) For categories where health index is not applicable, it is not used in the identification or justification for asset investment.

d) In Figure 1, for categories where the prioritization score is not applicable, the Health Index is used instead for prioritization for these assets.

e)

i. The Inspection results that are gathered are used in the Health Index calculation and the ACA models are run annually to determine the planned asset replacement. Assets which are in poor or very poor condition are selected for replacement.

Code A is assigned to assets which represent a safety issue, an environmental issue and/or imminent failure. The assets identified as Code A are replaced immediately. For example, a pad mount transformer or switchgear with extensive rust issues resulting in a loss of structural integrity or an extensive oil leak will be identified as Code A and will be immediately replaced.

Code B is assigned to assets which require additional evaluation. The Health Index calculation determines the replacement of Code B assets.

ii. The health index rating or prioritization scores are designed in such a way that a Code C rating will not result in poor condition on the ACA result. As such, it is unlikely that the asset would have a Code C rating and poor ACA result simultaneously.

**II-2-Staff-42**

**Ref: E G/T2, 5.3.3 Asset Lifecycle Optimization Policies and Procedures, p. 3, Figure 1 and E G/T2, 5.3.2 Overview of Assets Managed, p. 51, Figure 50**

PowerStream presents Health Index results for Wood Poles on Figure 50. However, on Figure 1 of the first reference, the Health Index score is identified as “Not Applicable” for “Pole Replacement.”

Please provide an explanation.

**RESPONSE:**

DS Plan Sec 5.3.2, Figure 50 does not represent a Health Index. Fig-50 represents the classification of Poles based on the remaining strength criteria obtained through the Pole testing program. PowerStream recognizes that the label below the figure is confusing.

Poles are prioritized for replacement based on the prioritization index outlined in the DS Plan, Section 5.3.3, page 8.

**II-2-Staff-43**

**Ref: E G/T2, 5.3.3 Asset Lifecycle Optimization Policies and Procedures, p. 5, l. 7-12**

PowerStream states:

> When an existing pole is replaced, PowerStream must install the new pole according to the current standards…If in any particular case, the pole has transformers, switches, or other equipment with significant remaining life, these are salvaged and re-used.

a) Please state how PowerStream determines if an asset is re-used or salvaged.

b) Please state the percentage of equipment that is re-used through this process.

c) Please state whether the re-use of equipment has been included as a cost savings in the forecast?

**RESPONSE:**

a) PowerStream staff follows an equipment reuse procedure.

b) PowerStream has been developing an inventory and accounting process to accurately capture the cost and quantity of equipment being reused. This involves aligning PowerStream's accounting processes to the current IFRS standards. Based on field experience, the percentage of equipment that is reused is believed to be relatively low based on the age of the typically replaced assets, and the quantities are not believed to be material. PowerStream does not have an accurate number.

c) The reuse of the equipment has not been included as cost savings in the DS Plan.

**II-2-Staff-44**

**Ref: E G/T2, 5.3.3 Asset Lifecycle Optimization Policies and Procedures, p. 6, l. 26-29 and Section IV/T1/G-AMPCO-9, p.29**

Please state whether or not statistical analysis has been done to determine actual useful life of asset classes used by PowerStream. If yes, please provide this analysis.

**RESPONSE:**

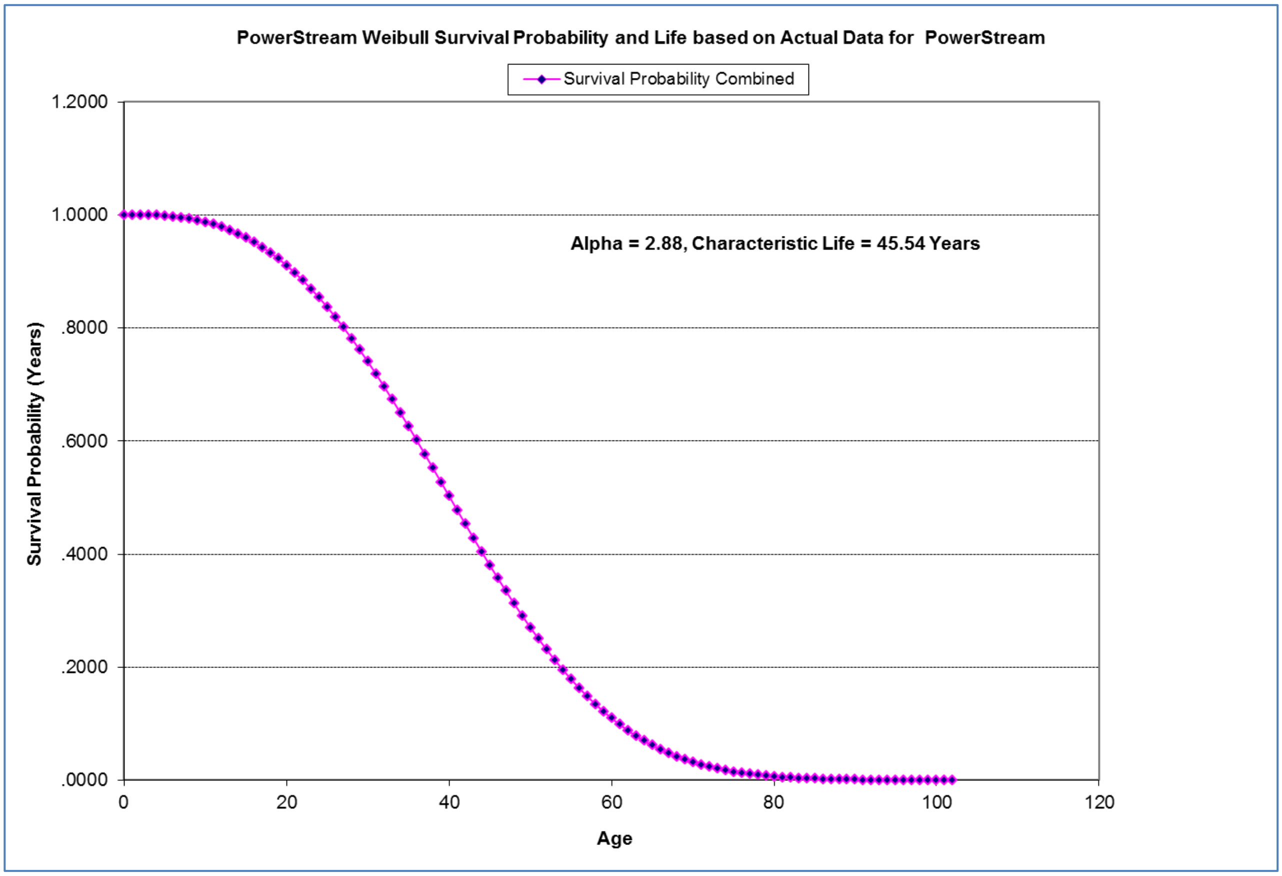
All of PowerStream's assets are modelled based on Weibull Distribution. As with any statistical analysis and modelling it requires an adequate sample size for the analysis to be accurate and reliable. For many assets PowerStream does not have adequate failure numbers to be able to run Weibull analysis. PowerStream has completed the Weibull Analysis for the Poles and Switchgears and the results are shown in Table 44.1 & 44.2 and Figure 44.1 & 44.2 below.

PowerStream Pole Model

**Table 44.1**

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| SUMMARY OUTPUT | | | | | | | | |
| | | | | | | | | |
| *Regression Statistics* | | | | | | | | |
| Multiple R | 0.909343594 | | | | | | | |
| R Square | 0.826905771 | | | | | | | |
| Adjusted R Square | 0.826571612 | | | | | | | |
| Standard Error | 0.52937233 | | | | | | | |
| Observations | 520 | | | | | | | |
| | | | | | | | | |
| ANOVA | | | | | | | | |
| | *df* | *SS* | *MS* | *F* | *Significance F* | | | |
| Regression | 1 | 693.466792 | 693.4668 | 2474.589663 | 1.9992E-199 | | | |
| Residual | 518 | 145.161763 | 0.280235 | | | | | |
| Total | 519 | 838.628555 | | | | | | |
| | | | | | | | | |
| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* | *Lower 95.0%* | *Upper 95.0%* |
| Intercept | -11.01249668 | 0.211102075 | -52.1667 | 2.4243E-208 | -11.42721813 | -10.5977752 | -11.42721813 | -10.59777523 |
| X Variable 1 | 2.883828636 | 0.057971943 | 49.74525 | 1.9992E-199 | 2.769939618 | 2.997717654 | 2.769939618 | 2.997717654 |
| Alpha | 2.88 | | | | | | | |
| Life | 45.54528142 | | | | | | | |

**Figure 44.1**




Typical Useful Life (TUL) is based on Kinectrics Inc. Report No. *K-418099-RA-001-R000 "Asset Amortization Study for the Ontario Energy Board"* for Wood Poles is 45 years.

## Table 44.2

**Weibull Analysis: Switchgear Failure Analysis**

**User Settings:**

| | |
|---|---|
| **Estimation Method** | Least Squares |
| **Confidence Level** | 97.5 |
| **Threshold** | 0 |

**Censoring Information:**

| | |
|---|---|
| **Number of Uncensored Observations** | 137 |
| **Number of Right Censored Observations** | 0 |
| **Total** | 137 |

**Model Summary and Goodness-of-Fit:**

| | |
|---|---|
| **Log-Likelihood** | -446.918 |
| **Anderson-Darling (unadjusted)** | 2.474 |
| **AD P-Value** | < 0.01 |

**Parameter Estimates:**

| Parameter | Estimate | SE Estimate | Lower 97.5% CI | Upper 97.5% CI |
|---|---|---|---|---|
| **Shape** | 3.349 | 0.316893 | 2.709 | 4.140 |
| **Scale** | 23.736 | 0.638715 | 22.347 | 25.212 |

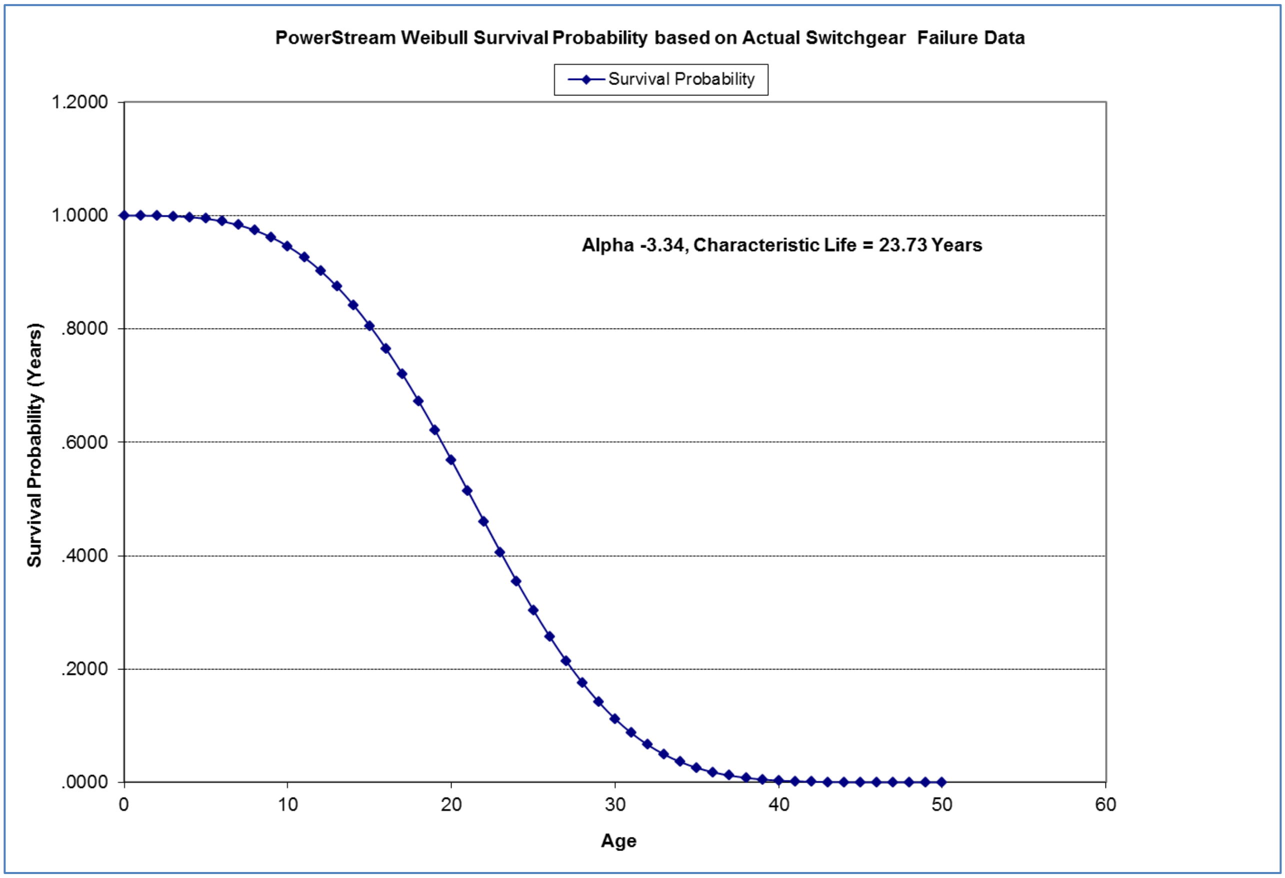
**Distribution Characteristics:**

| | Estimate | SE Estimate | Lower 97.5% CI | Upper 97.5% CI |
|---|---|---|---|---|
| **Mean (MTTF)** | 21.308 | 0.590183 | 20.025 | 22.672 |
| **Standard Deviation** | 7.016 | 0.579793 | 5.829 | 8.443 |

**Percentile Report:**

| Percentage | Percentile (Time) | SE Percentile | Lower 97.5% CI | Upper 97.5% CI |
|---|---|---|---|---|
| 0.1 | 3.018 | 0.600624 | 1.932 | 4.715 |
| 0.135 | 3.301 | 0.629226 | 2.153 | 5.061 |
| 0.5 | 4.883 | 0.752100 | 3.457 | 6.896 |
| 1 | 6.010 | 0.809675 | 4.444 | 8.129 |
| 5 | 9.778 | 0.880590 | 7.991 | 11.965 |
| 10 | 12.123 | 0.859540 | 10.341 | 14.211 |
| 25 | 16.362 | 0.751190 | 14.762 | 18.136 |
| 50 | 21.276 | 0.628925 | 19.912 | 22.733 |
| 75 | 26.168 | 0.726763 | 24.588 | 27.849 |
| 90 | 30.448 | 1.047064863 | 28.190 | 32.888 |
| 95 | 32.937 | 1.300 | 30.149 | 35.984 |
| 99 | 37.450 | 1.838 | 33.549 | 41.804 |
| 99.5 | 39.051 | 2.048 | 34.720 | 43.921 |
| 99.865 | 41.713 | 2.415 | 36.637 | 47.491 |
| 99.9 | 42.269 | 2.494 | 37.033 | 48.246 |

**Figure 44.2**




The characteristic life of the PowerStream Switchgear population is 23.73 years as opposed to useful life of 30 years. PowerStream has 1212 switchgear which are the air insulated out of the total population of 1847. The useful life of these switchgears is 15-20 years which results in lowering the characteristic life of the population. PowerStream has not changed the useful life and the failure curve of the switchgear based on this analysis.

**II-2-Staff-45**

**Ref: E G/T2, 5.3.3 Asset Lifecycle Optimization Policies and Procedures, p. 13,**

At the above reference, there is discussion of a "Storm Hardening and Rear Lot Remediation" program. It is stated that PowerStream has performed a review of the rear lot pockets:

> In 2012, a review of the rear lot pockets was performed. There are thirty-six (36) areas of various sizes. These assets are aging, with an average age of years forty-two (42) years, with the oldest being sixty-six (66) years old.

PowerStream further indicates that these assets "pose a potential safety risk to the public due to the planting of trees and installation of sheds and pools close to the lines" and that several potential options and associated costs were presented.

Finally, it is stated that a second review of options was performed and as a result, PowerStream is now proposing to annually replace areas of the rear lots supplies with front lot standard construction until they are remediated.

a) Please provide asset counts (poles, transformers, switches, km of conductors/cables) and the age profiles for each rear lot asset class for each of the 36 areas. If data are not available, please explain.

b) What options were considered as part of the "first review" and "second review" of the rear lot construction? Are these review documents available? If yes, please provide the documents.

c) Please provide historical references to safety incidents that have taken place with respect to rear lot construction – including incidents impacting safety to the public, as well as safety to crews.

d) Please clarify the difference between "replacement" of rear lot as opposed to "remediation".

**RESPONSE:**

a) The asset counts and age profiles for each rear lot asset class for each of the areas is indicated in Table 45a below.

**Table 45a**

| Location Reference # | Project | Number of Poles | Number of Transformers | Length of Circuit (m) | Average Age |
|---|---|---|---|---|---|
| 1 | Shirley/Vine | 13 | 2 | 534 | 56 |

| | | | | | |
|---|---|---|---|---|---|
| 2 | Blake/Kempenfelt | 10 | 2 | 186 | 63 |
| 3 | Wellington/Oak | 28 | 0 | 977 | 56 |
| 4 | North Park/Parkdale | 23 | 4 | 806 | 46 |
| 5 | Johnathan/Bothwell | 26 | 5 | 868 | 56 |
| 6 | Ottaway Ave. | 24 | 3 | 706 | 46 |
| 7 | Gunn/Oakley park Sq./St. Vincent | 37 | 4 but all In front | 1,297 | 56 |
| 8 | Marion/Pratt/Shannon | 30 | 6 | 1,214 | 57 |
| 9 | Alexander/Oliver | 14 | 1 | 481 | 52 |
| 10 | Regional Rd. 15/Victoria | 7 | 0 | 530 | 44 |
| 11 | Queen/Victoria E | 19 | 5 | 1,080 | 35 |
| 12 | Victoria W. of Downey | 4 | 3 | 200 | 59 |
| 13 | Sir Frederick Banting/Victoria E | 6 | 1 | 240 | 8 |
| 14 | Main W/Centre N | 9 | 2 | 360 | 25 |
| 15 | Burke/Country Club | 6 | 0 | 210 | 39 |
| 16 | Maria/Edward | 3 | 2-3ph banks | 106 | 43 |
| 17 | Maria st. near Robert st. E | 4 | 3 | 116 | 26 |
| 18 | Shannon Rd. at Main St. | 1 | 1 | 32 | 39 |
| 19 | Robert St. at Main North side | 4 | 2 | 108 | 34 |
| 20 | Tessier at west of Main St. | 4 | 2 | 55 | 27 |
| 21 | Fraser Ave. 3ph line & Perdue Pl./ Alphonsus Crt | 17 | 3 | 1,000 | 47 |
| 22 | East of Queen St. to Eastern Ave. / North of Greenway St. | 38 | 9 | 1,360 | 33 |
| 23 | East of Queen St. / North of Mill St. | 24 | 8 | 816 | 33 |

| | | | | | |
|---|---|---|---|---|---|
| 24 | North of Mill St. and East of Industrial Rd. and West of Queen | 22 | 3 | 724 | 44 |
| 25 | South of Mill St. / West of CPR Railway / East of Queen St. | 36 | 15 | 1,224 | 34 |
| 26 | Queen St. & Lionel Stone Ave. | 65 | 16 | 2,095 | 43 |
| 27 | Queen St. & Richmond St. | 27 | 8 | 848 | 46 |
| 28 | Yonge & Wellington (NW) | 126 | 6 | 4,600 | 46 |
| 29 | Islington & Sevilla (NE & SE) - {NE Side of Major Mackenzie/Islington} | 60 | 19 | 2,480 | 9 |
| 30 | Major Mackenzie & Warden (SW) | 30 | 21 | 1,360 | 8 |
| 31 | Main St. Unionville & Carlton (SW) - {NW Side of Hwy 7/Kennedy} | 134 | 42 | 4,932 | 50 |
| 32 | Royal Orchard | 178 | 67 | 5,600 | 49 |
| 33 | Hwy 7 & McCowan (SE) | 86 | 24 | 2,840 | 32 |
| 34 | Steeles & Henderson (NE & NW) - {NW Side of Steeles/Bayview} | 97 | 34 | 3,440 | 20 |
| 35 | Bayview & Steeles (NE) | 106 | 80 | 9,364 | 52 |

**Note that previous 36 areas have been consolidated into 35 areas.*

b) PowerStream's four remediation options in the "first review" and "second review" are shown below:

- Option 1 – Replace existing rear lot with new rear lot overhead
- Option 2 – Replace existing rear lot with new front lot overhead
- Option 3 – Hybrid – Install primary cable & secondary at front lot underground; replace/keep pole & secondary at rear lot
- Option 4 – Replace existing rear lot with new front lot underground

The "first review" was conducted in the PowerStream Reliability Committee meeting of December 19, 2012. The "second review" was conducted in 2014, after the 2013 ice storm and the CIMA Storm Hardening Report.

The first review and second review reports are included as noted. Additionally, the latest report is also included.

| Report | PDF File Name |
|---|---|

| | |
|---|---|
| a) First Review | Appendix Staff 45.1 - Rear Lot Supply Review (Nov 21 2012) |
| b) Second Review | Appendix Staff 45.2 - Rear Lot Supply Remediation Plan – Draft 2 (August 12, 2014) |
| c) Latest Review | Appendix Staff 45.3 - Rear Lot Remediation Program (March 31, 2015) |

c) The safety incidents that have taken place with respect to rear lot are listed in Table 45c below.

**Table 45c**

| H&S Incident # | Incident Date | Incident Category | Department | Description of Incident |
|---|---|---|---|---|
| 621 | 09/08/2011 | Near Miss (Incident) | Lines North | Moving trailer to backyard, was hooking up last trailer beside one another. Putting down long leg from driver side did not see front corner on leg. |
| 630 | 10/13/2011 | Near Miss (Incident) | Lines South | While attempting to refuse Backyard 1 phase riser switch with extendable Switch stick, fuse and stick came in contact with over grown trees around the pole. The fuse dislodged and fell grazing left knee. |
| 740 | 05/23/2012 | Property/Equipment Damage & Operational Loss | Lines North | Cutting service down to change over to underground. Climbed the pole in the backyard with a ladder, belt and spurs. There was a fence and a tree we had to get over in order to get to the top of the pole. When I was ready to cut service clear I spread secondary legs apart, got cutters out instead of cutting single hot leg. I reached out and started to cut triplex. I stopped when I heard arcing. |
| 1025 | 12/16/2013 | Injury/Illness | Engineering Services | When walking towards the rear lot of the property to attend a meeting, I slipped and fell on the ground, step on uneven surface covered with ice and snow. Knee suffered a strain injury, swolen and have difficulty walking. |
| 1324 | 06/22/2015 | Injury/Illness | Lines South | Working from a pole/backyard - lifting secondary bus to new location on new pole. Strained back. Lifting approx. 1 foot using 2 people on same pole. |
| 1343 | 07/28/2015 | Injury/Illness | Lines South | As the student was stepping down from an interlock garden supporting wall (they were entering a backyard for a backyard pole job), they rolled their ankle. |

d) In the context of Rear Lot Supply Remediation Program, “replacement” and “remediation” are the same.

**II-2-Staff-46**

**Ref: Section III, T4/S1, BOMA-11, Appendix A, Section 5.14 – Other Initiatives**

At the above reference, PowerStream provides a description of the "Rear Lot Construction Elimination" program. It is stated that existing rear lot construction "presents some operational and reliability issues" – however, it is noted that "Cost and CMI saving are not estimated at this time"

a) Please provide historical reliability (SAIDI/SAIFI or CI/CMI) data for each of the 36 areas and combined as well as the expected estimated reliability savings in 2015-2020.

b) Please confirm that the expected estimated reliability savings for the Rear Lot remediation program are provided in the Five Year Work Reliability Work Plan 2015-2019. If not, please provide the expected reliability savings in 2015-2020.

**RESPONSE:**

a) PowerStream tracks the reliability on a feeder level basis and as such, the historical reliability (SAIFI/SAIDI or CI/CMI) data for each of the areas is not available.

b) The projected reliability savings are provided in the five year reliability work plan. No savings were projected for year 2020 in the Reliability Work Plan (previously submitted in IR Response BOMA-11, Appendix A) however it is expected to save 100,000 CMI's.

**II-2-Staff-47**

**Ref: Section IV, T2, TCQ-2 G-SEC-19, Appendix B, Hardening the Distribution System Against Severe Storms – Final Report**

At the above reference, various options are presented for managing Rear Lot infrastructure. This includes:

(1) replace existing rear lot overhead with new rear lot overhead,

(2) replace existing rear lot with new front lot overhead,

(3) a hybrid approach to underground primary and maintain secondary overhead connections, and

(4) replace existing rear lot overhead with front lot underground.

While the report provides some recommendations between Options 3 and 4, there is no specific option that the report recommends. The report indicates that while Option 2 is feasible, it is not achievable due to public and political backlash against new overhead plant in an underground area.

a) When selecting the most viable option out of the 4 presented in the report, did PowerStream produce a full business case, which quantified the total life-cycle costs associated with each option? Total life cycle costs take into account the risks of the existing assets to be replaced (reliability impacts, ongoing maintenance costs, safety and environmental impacts) as well as the capital costs of the new assets to be installed. If yes, please provide this business case. If the business case is not available, please explain what option PowerStream concludes to be the most viable option.

b) If available, please provide any customer engagement programs or surveys that illustrate differences between "overhead" and "underground" areas, and justify that there is a risk of political and public backlash if the utility were to proceed with an overhead installation within an underground area.

c) Appendix D of the same report provides a Rear Lot Priority List of all activities from 2015 onwards to 2029. Please provide further information behind this prioritization approach – namely how PowerStream determined which areas were high priority and which areas were low priority. Please explain what quantified metrics and costs were considered as part of this analysis, including mitigated risks, capital cost requirements and ongoing maintenance costs.

d) Please confirm that PowerStream follows Appendix D to define the priority and develop budget estimates for the Rear Lot remediation program in the DSP.

e) Please explain the zero spending level in 2021-2023 in the recommended Rear Lot priority list in Appendix B.

**RESPONSE:**

a) During the “first review” in 2012, a life cycle cost analysis was completed. Refer to Appendix Staff 45.1.

After the 2013 ice storm outage, based on discussion with CIMA and internal stakeholders, it was decided that Option 4 (replace existing rear lot overhead with front lot underground) is the preferred option. Leaving secondary at the rear of the lots will not solve reliability issues as seen from the December 2013 ice storm.

b) PowerStream has not completed a customer engagement survey specifically for rear lot remediation. PowerStream’s Municipalities do not permit new overhead residential distribution.

c) The priority listing was completed using the asset condition information at the time (mainly pole condition). It was intended to provide a general picture and high level long-term plan. On an on-going basis, PowerStream will continue to review and revise the priority list based on new asset condition information and coordination with other capital work programs.

The annual projects are selected and prioritized based on the following factors:

- Asset Age
- Asset Condition
- Imminent Health, Safety and Environmental Issues
- Standards/Directive Violation, and Obsolescence/Non-compliance
- Capacity Adequacy for Existing and Future Loading
- Criticality of the Circuit
- Failure Statistics
- Customer Complaints

During the annual budget submission and approval process, each location will be justified individually, using PowerStream C55 Budget Tool, which takes into consideration all the cost and the benefit/risk parameters of the proposed project.

d) Appendix D of G-SEC-19, Appendix B, Hardening the Distribution System Against Severe Storms – Final Report is subject to future annual review and revision. On an on-going basis, PowerStream will continue to review and revise the priority list based on new asset condition information and coordination with other capital work programs.

e) The zero spending level in 2021-2023 in the recommended Rear Lot priority list in Appendix B is explained as follows:

The priority list (Appendix B) is proposed by CIMA in the CIMA final report. This priority list reflects one of the CIMA's proposals to accelerate the mitigation program for the first 6 years (2015–2020) for the older locations and post 1980 plant can be scheduled for the 2024-2030 period. Please note that PowerStream is not adopting CIMA's priority list and that PowerStream's priority list includes projects in every year (does not have zero spending for the years 2021-2023).

The following is the extract from CIMA Final Report Page 62.

*"5.2.4 Potential Practice Adaptations*

*In reviewing PowerStream's practices for backyard construction, there are a number of initiatives that PowerStream should consider adopting:*

1. *Consider accelerating the mitigation program to expeditiously deal with plant installed in the 1950s through to the 1970s that are already past the Typical Use for Life (TUL) pole point (45 years). Consider a 6 year-$41M program to expedite replacement of pre- 1980 vintage plant. This will partially address expected customer outcomes and mitigate risk of backyard plant subject to a future freezing rain event similar to the 2013 ice storm. Post 1980 plant ($18.6M program) can be scheduled for the 2024 – 2030 period."*

**II-2-Staff-48**

**Ref: Section III, T1/S1, G-AMPCO-28 and Section IV, T2, TCQ-2 G-SEC-19, Appendix B, Hardening the Distribution System Against Severe Storms – Final Report**

At the first reference above, PowerStream provided a breakdown of the rear lot expenditures taking place from 2015 onwards to 2020. This response also provides the number of projects and areas that will be converted, along with an expected completion date of 2029.

a) Please explain why the spending levels for Rear Lot in 2016-2020 are constant in spite of a changing number of projects and areas. If more up-to-date estimates for the rear lot remediation program in 2015 to 2020 are available, please provide updated numbers.

b) Please reconcile the numbers in part a) with the second reference CIMA report, Appendix D, Rear Lot Priority List 2015-2029 numbers provided in Project Cost numbers.

c) Please explain how PowerStream determined that 2029 should be the end date for the Rear Lot program. Please describe other options, including conversion of Rear Lot earlier than 2029, or later than 2029 that were considered while making the decision on the completion year target.

**RESPONSE:**

a) The proposed spending levels in the long-term Rear Lot Remediation program are kept relatively constant to smooth out the expenditures over the plan. The estimated spending level in a given year is dependent on the number of customers affected, and as such, there are cases where more than one small area may be budgeted in one year; on the other hand, there are cases where one large area may be split into smaller phases and to be budgeted over more than one year.

Although PowerStream does not have any actual cost to date for the underground option, at this time it is estimated that the unit cost for the underground option will be higher than what was previously estimated. It should be noted that unit costs will vary widely depending on the actual complexity and design details at each site. PowerStream is working on getting a refined estimate and may have to extend the length of the Rear Lot Remediation program to more than 15 years if the unit cost is higher than expected.

b) PowerStream has not adopted the accelerated schedule that CIMA indicated in CIMA's report Appendix D. PowerStream does not have sufficient funds to accelerate the schedule. On the contrary, it is likely that PowerStream will have to spread the schedule into longer period (i.e. more than 15 years).

c) In determining the program length PowerStream considered asset condition, storm frequency and affordability.

Completion of the Rear Lot program earlier than 2029 will require an increase in the budget available for Rear Lot program each year. Completion of the Rear Lot program later than 2029 will add additional risk to system reliability and customer service because the assets in the rear lot will deteriorate more and may fail more often.

**II-2-Staff-49**

**Ref: Section III, T1/S1, B-CCC-16 and Section IV, T2, TCQ-2 G-SEC-19, Appendix B, Hardening the Distribution System Against Severe Storms – Final Report**

At the first reference, PowerStream states that:

> 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.

a) Please provide detailed justification for the estimate per customer used for Rear Lot project spending.

b) Please reconcile the estimated construction cost per customer with the Project Cost in Appendix D of the CIMA report (second reference).

**RESPONSE:**

a) The previous estimate of $12,400 per customer is applicable for Option 3 (Hybrid Option). This estimate was calculated using an example area in Markham (Romfield subdivision). The total cost estimate was $2,190,805 involving 177 customers, which results to a unit cost of $12,377 per customer, rounded to $12,400 per customer.

b) PowerStream did not adopt the accelerated schedule that CIMA indicated in CIMA's report Appendix D. It was recognized that PowerStream would not have sufficient capital funds to accelerate the schedule. On the contrary, it is likely that PowerStream will have to spread the schedule into longer period (i.e. more than 15 years).

In the CIMA's report Appendix D, there are two types of cost listed (by CIMA):

- Cost for Hybrid Option; and
- Cost for Underground Option.

The unit cost for Hybrid Option is the same as that from PowerStream's unit cost.

The unit cost for Underground Option was obtained (by CIMA) by multiplying the unit cost for Hybrid Option with a multiplier factor. This multiplier was used to reflect the incremental cost to go from the Hybrid Option to the Underground Option.

Example:

- Unit Cost for Hybrid Option = $12,400 per customer
- Unit Cost for Underground Option = $12,400 x 1.47 = $18,218 per customer

**II-2-Staff-50**

**Ref: E G/T2, 5.3.3 Asset Lifecycle Optimization Policies and Procedures, p. 14, Table 1**

Please provide a source to justify the useful life for IT Asset classes shown in this table.

**RESPONSE:**

In 2012, PowerStream transitioned to IFRS. This required the assessment of useful lives for all of PowerStream's assets.

The assets were assessed using the Kinectric's depreciation study, including the IT asset classes included in Table 1, DS Plan Sec 5.3.3 Pg 14. This was provided as evidence as part of the 2013 Cost of Service application. The useful lives are reviewed on an annual basis and there have been no changes made since the initial values were set. Refer to Appendix J-3-1, (Table F-2 from the Kinectrics Report) of the Rate Application.

**II-2-Staff-51**

**Ref: E G/T2, 5.3.1 Asset Management Process Overview, p. 24, l. 10-14, 5.3.3 Asset Lifecycle Optimization Policies and Procedures, p. 16, l. 8-9 and p. 17, Figure 5**

At the first reference, PowerStream states that the:

> [Asset Management & Decision Making] … process also considers input from customers and recommendations from interdepartmental committees. The proposed projects are then placed into the optimization process and applied within the capital budget threshold to generate the optimal list of projects/programs for a given year (projects with the highest value are included in the year's portfolio).

PowerStream also states that "Business units prepare detailed budgets, justifications and business cases for project and enter these into the optimization tool".

a) Please provide the Value Function of the optimization tool with a complete set of parameters and weightings.

b) What is an objective function of the Value in the optimization tool? Please provide a formula, whether an objective is to minimize or maximize.

c) In addition to the objective function in part b) please provide inequality and equality constraints used to optimize the Value. Please describe how these constraints are being set?

d) Please describe an optimization algorithm utilized by C55 to define an optimal list of projects.

e) Please provide a full list of projects with the associated capital dollar amount that were placed into the optimization process for the development of 2015-2020 DSP.

f) Please identify the capital budget threshold and any other constraints applied for each of the years.

g) Please provide a Single Value for the Value Measure, the Value of Risk Mitigation and Residual Risk for each of the programs/projects that were run through the C55 optimization tool for the purpose of development of the 2015-2020 DSP.

h) Please identify the projects that were placed into the optimization process but not included in the submitted DSP plan as a result of the optimization.

i) Please provide the Investment Value Report and Scenario Comparison Report (shown on the Figure 5) from the C55 system for the run that was used to optimize DSP programs/projects for 2015-2020:

**RESPONSE:**

a) The Value Function, including a complete set of parameters and weightings, is described in Appendix Staff 51a – PowerStream Value Function v4b (named the VFID).

b) The objective function is to maximize the total Value of the portfolio.

c) Refer to (f) below.

d) The optimization uses Linear Programming to determine the maximum Value that can be obtained from the projects under consideration while not exceeding the specified constraints.

e) Refer to Appendix Staff 51e, Full Project Listing Prior to Optimization.

f) The capital budget targets were filed as a response C-CCC-22 and can be found in Section III, Tab 1, Sch 1, pg. 47. No other additional constraints were set. The constraint values can be referenced in G-AMPCO-7(f) submitted in the previous interrogatories.

g) Appendix Staff 51g - Project Value Report, shows the value for each program/project that was run through the C55 optimization tool. In addition to showing the overall Total Value, it also shows the value of each project/program obtained in each Risk and benefit category.

h) Refer to Table 51h below to see a listing of all the 2015-2020 projects placed in the optimization process, but as a result of optimization did not receive any funding during 2015-2020, and were so excluded from the DS Plan.

**Table 51h**

| | Project Code | 2015-2020 Projects Excluded from DSP due to Optimization |
|---|---|---|
| 1 | 102410 | Account Reconciliation Tracking System |
| 2 | 100225 | Add one Additional 27.6 kV Cct on Dufferin St from Major Mackenzie Dr to Teston Rd |
| 3 | 102437 | Asset Tracking Form - Auto Upload |
| 4 | 102397 | Automate VISA Form, Upload to JDE |
| 5 | 102408 | Automated time entry reminder |
| 6 | 102426 | Automation of WIP reporting |
| 7 | 102427 | CC&B Reports |
| 8 | 102246 | Cyber Security - Implement Encryption on non-PowerStream network segments |
| 9 | 101495 | CYME Gateway Software Phase 2 |
| 10 | 100625 | Design software and GIS Integration |
| 11 | 103083 | Design software Customization Enhancements |
| 12 | 101563 | Electronic Key Kiosk System |
| 13 | 101684 | Expand Communication Network to isolated Stations. |
| 14 | 101169 | Expense Module Implementation within JDE |
| 15 | 102405 | FileNexus, Account Reconciliation Retention |
| 16 | 102542 | Finance Process Improvements |
| 17 | 102259 | GIS Aerial Photography (Ortho Images) |
| 18 | 102255 | GIS Data enhancement |
| 19 | 102776 | GIS Data Model Enhancement |
| 20 | 102770 | GIS Software Upgrade |
| 21 | 102758 | GIS StreetScape Images |
| 22 | 101733 | Greenwood Expansion 20MVar Cap Bank |
| 23 | 100459 | Harvie Rd. MS - 44kV Supply to Harvie Rd. MS |
| 24 | 100461 | Harvie Rd. MS-13.8kV Feeder Integration |
| 25 | 102458 | Highway Crossing Remediation - Hwy 407/ Hwy 27 |
| 26 | 104018 | HR and OE Emerging Projects |
| 27 | 100159 | Hydro One Asset Purchase - Alliston |
| 28 | 102239 | Implementation of Cyber Intrusion Appliance at a PowerStream Transformer Station |
| 29 | 102438 | Implementation of Treasury Management software |
| 30 | 102220 | Insights license & support |
| 31 | 102403 | Insights Reconciler Module (Inventory, AR, bank) |
| 32 | 102185 | Install a Second Supply to PowerStream's Addiscott Office |
| 33 | 103028 | Installation of a New JMUX Node at VTS1-T1T2 |
| 34 | 103268 | Inventory system/process upgrades and warehouse equipment replacements |
| 35 | 102079 | JD Edwards Additional Module Planning |
| 36 | 101241 | JD Edwards Mobility Planning |
| 37 | 101963 | JDE Accounting/Payroll Module Improvements |
| 38 | 103354 | Light and Miss Equipment for 2018 |
| 39 | 101932 | Lock Box retro-fits |
| 40 | 102424 | MAR Invoice Upload |
| 41 | 100726 | Mobile Designer for Service Layout Technicians |
| 42 | 102775 | Mobile GIS Implementation |
| 43 | 102985 | OM&A Budget database improvements |
| 44 | 102991 | OMS integration with Enterprise Work Force Management Solution. |
| 45 | 102072 | On-Line, On-Time (OLOT) for Inside Union Staff |
| 46 | 102409 | Pay Stubs and T4's to a Secure Mailbox for all Staff |
| 47 | 100796 | Pole line installation on Dufferin St - Phase 2 |
| 48 | 103660 | PS24 Expansion |
| 49 | 103672 | Purchase of a promotional tent, associated banners and accessories. |
| 50 | 103663 | Purchase of a two corporate display units, associated banners and accessories. |
| 51 | 103104 | Purchase of Design software |
| 52 | 102425 | Receipt of electronic MAR payments |
| 53 | 103350 | Replace Cargo Van Unit# 32 |
| 54 | 103302 | Replace pick up Unit# 510 |
| 55 | 103304 | Replace pick up Unit# 511 |
| 56 | 103305 | Replace pick up Unit# 512 |
| 57 | 103306 | Replace pick up Unit# 513 |
| 58 | 103307 | Replace pick up Unit# 514 |
| 59 | 103303 | Replace Pickup unit# 509 |
| 60 | 101937 | Retrofit Bulk to Suite Metering |
| 61 | 100318 | Second Supply to Doney Cr. |
| 62 | 102117 | Connect Walker TS to City Water and Sewer |
| 63 | 102059 | Installation Programable InfraRed Cameras-SWI Video system-Integrated with CMMS-2 TS |
| 64 | 102931 | Paving of MS & TS Station Driveways |
| 65 | 102050 | Various Stations-Station Lighting Upgrade/Retrofit-Energy Efficiency Lighting-Program Multiyear |
| 66 | 101209 | Station Security - Station Card Access at Greenwood and Greenwood Expansion TS and Torstar TS |
| 67 | 100055 | Station Service transfer panels |
| 68 | 101965 | Subdivision Data Base |
| 69 | 102511 | Third Party Contact Centre Systems Integration- Major Outages |
| 70 | 102420 | Transform AP - Change Requests and Enhancements |
| 71 | 102091 | TransformAP Upgrade |
| 72 | 103065 | Upgrade Advanced Distribution Management System (ADMS) to latest version release. |
| 73 | 100452 | Web Based GIS Upgrade - ArcGIS Server |
| 74 | 101880 | Year end and month end close automation |

i) Refer to Appendix Staff 51g, Project Value Report, and Appendix Staff 51i, Scenario Comparison Report.

**II-2-Staff-52**

**Ref: E G/T2, 5.3.3 Asset Lifecycle Optimization Policies and Procedures, p. 20, l. 22-28 and p. 22, l. 1-7**

At the second reference, PowerStream states:

> The Value of Risk Mitigation in all risk categories is computed using the same methodology…For each risk the project owner specifies both the consequence and probability of consequence.

a) For each of the risk mitigation categories at the first reference (on page 20) (IT Capacity, Financial, Environmental, Safety, Distribution, Compliance), please provide a description of how the project owner would select consequence values along with the sources of those values and rational for their applicability to PowerStream (for example - cost of a safety incident both direct and indirect).

b) Please state how consistency in assigning consequence and probability is maintained across all projects in cases where different authors each populate their own consequences and probabilities.

**RESPONSE:**

a) For each risk category the project owner selects the appropriate consequence category based on the consequence table as described in the VFID. In addition to selecting the appropriate consequence level, the project owner provides a justification as to why that level was chosen. For example, for project 101562: Arc Flash Mitigation Projects, the project owner selected the consequence level as “Major” from the consequence table in Appendix A1 of the VFID. One row of that table is copied here for convenience. The project owner provided the following justification for the selection of the consequence level: “The consequence is classified as 'Major' because an arc flash occurrence has the potential to be life-threatening. This project studies the energy levels in the stations and creates awareness of the hazardous locations.”

| | Catastrophic | Major | Moderate | Minor | Very Minor | None |
|---|---|---|---|---|---|---|
| SAFETY | Any loss of life and/or multiple serious long term health implications as a result of our actions | Multiple life threatening injuries and some long-term health implications as a result of our actions | Some life threatening injuries | Reportable incident with serious but non-life threatening injuries | Reportable Incidents | No risk of incidents |

b) In addition to selecting the actual values, project owners are expected to provide a rationale for those selections. The valuation of all projects is reviewed and approved by Section Heads for consistency. The Capital Budget Supervisor reviews all projects to look for scoring anomalies (negative or excessively high). In addition to this review process, as part of a review of the optimization results, if any projects have values that appear to be out of line with their peer projects, the Optimization team is able to drill into the assessments to check for consistency and reasonableness.

**II-2-Staff-53**

**Ref: E G/T2, 5.3.3 Asset Lifecycle Optimization Policies and Procedures, p. 26, Table 2, p. 27-28, Vegetation Management and Section III, Tab 1, Schedule 1, p. 83-84, F-Energy Probe-7, p. 144 G-AMPCO-11**

PowerStream's vegetation management program costs in 2013 were $1.461M, but by 2020 will be $4.716M representing an overall annual increase expected to be $3.255M.

OEB staff calculates the year over year increases in Vegetation Management spending as the following (using Table 2 of the above references):

| **Activity** | **2016 vs 2015** | **2017 vs 2016** | **2018 vs 2017** | **2019 vs 2018** | **2020 vs 2019** |
|---|---|---|---|---|---|
| **Vegetation Management** | 25.3% | 20.4% | 17.1% | 14.7% | 13.0% |

a) Please explain in detail and justify the continuing cumulative increase and fluctuation in vegetation management spending.

b) Please provide average unit costs (e.g. per km, per tree cut etc.) for vegetation management for the historical period (2011-2014) as well as for the forecast period for each of the years. Please discuss cost trends, including inflationary factors, reasons for increases, and attendant productivity measures undertaken and planned to offset or reduce unit costs.

c) Please state whether or not PowerStream has performed any risk-based economic analysis to justify an increased budget for vegetation management. If yes, please provide the results.

d) Please state whether or not PowerStream conducts any reliability-based tree trimming practices for targeting areas using cycles adjusted for reliability impact. If yes, please provide the results.

e) If available, please provide a benchmark (at least minimum, maximum and average values) for a tree trimming cycle for rear lots in other similar utilities. Please describe whether and how these benchmarks were incorporated into PowerStream's business planning and forecast.

f) Please provide 2011-2014 and 2015 year-to-date numbers for SAIDI/SAIFI, tree contacts as a cause, excluding Major Event Days (MED).

g) Please provide the expected annual reliability improvements (SAIFI/SAIDI, tree contacts as a cause), excluding MED for each of 2016-2020 as a result of new tree trimming cycles, separately for rear lot and front lot lines. Please apply Customer Interruption Costs for improved delta in reliability to calculate a monetary equivalent of reliability improvement results.

h) Please apply Customer Interruption Costs for improved delta in reliability in part e) to calculate a monetary equivalent of reliability improvement results.

i) Please provide expected 20-year average annual reliability improvements (SAIFI/SAIDI, tree contacts as a cause) MED only as a result of a new tree trimming cycles, separately for rear lot and front lot lines. Please apply Customer Interruption Costs for improved delta in reliability to calculate a monetary equivalent of reliability improvement results. Please note that 20-year average is requested to smooth out Major event storms over a longer period of time.

**RESPONSE:**

a) 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 mature trees, including areas with rear-lot distribution. 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 Ice Storm and as noted in the response to part (c) below significant weather is trending to increase in the future, therefore reviews were conducted around how the system could be made more resilient to mitigate the impact of significant weather events. Vegetation management practices were part of these reviews, and an external report by CIMA Consulting recommended several enhancements to the vegetation management as noted in the application at Section IV, Tab 2, TCQ-2, G-SEC-19, Appendix B.

For the period 2016 through 2020, vegetation management budgets increase by approximately $500,000 each year to cover the cost of these enhancements to the Vegetation Management Program. These enhancements are an important aspect of PowerStream's objective of strengthening its distribution system to mitigate the impact of severe weather events, and will result in improved system reliability, safety and value to our customers.

b) Please see response to II-AMPCO-21 which shows the average OM&A vegetation management cost per km of overhead line for historical and forecast years.

c) In the aftermath of the 2013 Ice Storm, CIMA Consulting was engaged to undertake a study into how the PowerStream distribution system could be hardened to better withstand the impact of major weather events such as ice storms. The study also assessed how vegetation management practices could be enhanced to mitigate the impact of significant weather events. CIMA concluded that the PowerStream Vegetation Management Program follows good utility practice, but recommended enhancements to the program in order to better protect the system from the adverse impacts of significant weather events. The study included an assessment of the risks associated with significant weather patterns and their impact upon vegetation and, consequently, power lines. Key findings of the study are summarised below:

- Wind speeds related to significant weather events are expected to increase in future, increasing the risk of vegetation-related contacts with power lines;
- Frequency and intensity of ice storms is expected to increase in future, thereby increasing the risk of falling tree limbs with consequent impact upon power lines;
- During the 2013 Ice Storm, a number of outages were caused by mechanical teardown of power lines or contact due to falling branches or the failure of trees outside the conventional trim zone. Therefore, the study recommended that PowerStream enhance the tree trimming zone, adopt a “blue sky” approach to overhanging limbs, and implement a hazard tree removal program; and
- In support of these recommendations, the CIMA study referenced vegetation management best practices adopted by other utilities and also referenced other studies on the subject.

The CIMA study also assessed the cost of the recommended enhancements in relation to their expected positive impact. The CIMA study is located in the application at Section IV, Tab 2, TCQ-2, G-SEC-19, Appendix B.

d) At present, PowerStream does not have sufficient data by localised area to tailor vegetation management cycles to specific areas based on reliability performance. PowerStream is investigating how such data can be effectively captured and maintained, and such analysis may factor into the vegetation management program in future. However, PowerStream does to some extent utilise reliability performance in planning its vegetation management program. At a macro level, the poor performance of rear-lot areas during the 2013 Ice Storm led to the decision to adjust the vegetation management cycle in those areas. At a more micro level, PowerStream's Worst Performing Feeder program entails an annual reliability assessment of the entire distribution system and the 20 worst-performing feeders are identified. If Tree Contacts were a significant contributor to the poor performance of any identified feeders, then those circuits are targeted for specific vegetation management activity.

e) Benchmarked values for a tree trimming cycle for rear lots in other similar utilities is not available. The necessity to adopt a two-year cycle in PowerStream's rear-lot areas was based on the tree-related devastation in these areas during the 2013 Ice Storm. PowerStream recognized that additional emphasis on vegetation management was required in the rear-lot areas. A two-year cycle will allow more effective vegetation control because of the significant challenge associated with achieving adequate cutbacks in these areas. The adoption of a two-year cycle was based on specific conditions and experiences within PowerStream's service territories.

f) Table 53f below provides 2011-2014 and 2015 year-to-date numbers for tree contact-related SAIDI and SAIFI, excluding Major Event Days (MED).

**Table 53f**

| Year | SAIFI – Tree Contact Excl. MED | SAIDI – Tree Contact excluding MED (Minutes) |
|---|---|---|
| 2011 | 0.028 | 1.82 |
| 2012 | 0.053 | 3.05 |
| 2013 | 0.081 | 6.63 |
| 2014 | 0.076 | 3.24 |
| 2015 ytd. | 0.041 | 3.00 |

g) Insufficient data is available for expected reliability improvements to be broken down by rear-lot and front-lot. From an overall system perspective, by 2020 PowerStream expects to achieve a 30% improvement over the 5 year period SAIDI due to tree contacts. From 2011 to 2014 inclusive, the average annual SAIDI due to tree contacts is 3.68 minutes. Therefore, by 2020 PowerStream forecasts the annual tree-related SAIDI to be reduced by 1.1 minutes. Forecasted yearly improvements, in minutes and Customer Interruption Cost benefits, are shown in Table 53g below for the period 2016-2020. PowerStream uses a figure of $20 per kWhr as duration cost and $20/kW as frequency cost to calculate the cost per Customer-Minute of Interruption (CMI). CMI savings are calculated for a customer base of 360,000. As shown in Table 53g below, the dollar benefit from expected reliability gains far outweighs the vegetation management budgeted costs.

**Table 53g**

| Year | Forecast Cumulative year over year SAIDI improvement (Minutes) | Forecast CMI savings | Forecast Customer Interruption Cost savings (Millions 0f $) | Vegetation Management Budget (Millions of $) | Cost/Benefit Ratio |
|---|---|---|---|---|---|
| 2016 | - | - | - | 2.581 | - |
| 2017 | 0.28 | 100,800 | 7.06 | 3.106 | 0.44 |
| 2018 | 0.55 | 198,000 | 13.86 | 3.637 | 0.26 |
| 2019 | 0.82 | 295,200 | 20.66 | 4.174 | 0.20 |
| 2020 | 1.10 | 396,000 | 27.72 | 4.716 | 0.17 |

h) As explained in part (g), PowerStream has not broken out reliability improvements by rear-lot vs. other types of construction. Overall Customer Interruption Cost savings are shown in (g).

PowerStream has not quantified expected 20-year average MED-only tree-related reliability improvements as a result of the new tree trimming cycles, because of the challenge associated with accurately predicting events that could result in MEDs. MEDs typically result from storm activity, but the impact on the distribution system can depend on factors such as the type of storm (wind, ice, snow, etc.), location and breadth of the weather pattern, and its intensity and duration. Evidence indicates that severe weather events are becoming more frequent, and a significant weather-related event has generally occurred on an annual basis over the past few years. The December 2013 Ice Storm resulted in a loss of 179 million CMIs, and was classified as a Most Prominent Event under CEA guidelines. If it is conservatively assumed that such an event would occur once every 20 years, and the reliability improvement would be 10% of the CMIs lost during the Ice Storm, then the benefit in terms of avoided Customer Interruption cost would be $1.25 billion. This is a significant benefit compared to the budgeted vegetation management costs.

**II-2-Staff-54**

**Ref: E G/T2, 5.3.3 Asset Lifecycle Optimization Policies and Procedures, p. 30, l. 22-25**

PowerStream states that "Within PowerStream's ACA models, curves have been developed to indicate a correlation between asset condition/age and failures, and depict the likely expected number of failed units over time."

a) Please provide the failure curves function for all the asset classes.

b) Please provide any statistical analysis which shows the correlation between asset age/condition and failure rate to substantiate the curve development.

c) Please provide the calculated expected number of asset failures in 2014 for each asset class based on the failure curves. Please compare it to the actual failure counts.

d) Please state whether or not PowerStream has utilized failure curves and implied asset condition improvement through the DSP for the purpose of developing expected reliability performance of the system (SAIDI/SAIFI) in 2015-2020. If yes, please provide a description of the methodology, including expected asset condition and reliability improvements.

**RESPONSE:**

a) The failure curves function for all the asset classes are shown in the Table 54a below.

**Table 54a**

| **Asset Class** | **Shape** | **Scale** |
|---|---|---|
| TS Transformers | 3.0 | 50.5 |
| MS Transformers | 3.0 | 74.77 |
| Circuit Breakers – Vacuum | 3.0 | 74.77 |
| Circuit Breakers - Air | 3.0 | 74.77 |
| Circuit Breakers - Oil | 3.0 | 59.8 |
| Circuit Breakers – SF6 | 3.0 | 52.4 |
| 230 kV Primary Switches | 3.0 | 66.9 |
| MS Primary Switches | 3.0 | 74.77 |
| Capacitor Banks | 3.0 | 37.41 |
| Station Reactors | 3.0 | 66.9 |
| Station Service Transformers | 3.0 | 83.24 |

| | | |
|---|---|---|
| 230 kV Primary Metering Units | 3.0 | 35 |
| TS P&C Relays - Electromechanical | 3.0 | 40 |
| TS P&C Relays – Solid State | 3.0 | 35 |
| TS P&C Relays - Microprocessor | 3.0 | 25 |
| Distribution Transformers | 3 | 83.24 |
| Distribution Switchgear | 3 | 40.53 |
| Wood Pole | 2.88 | 45.54 |

b) Refer to response to Staff 44.

c) The ACA studies which were conducted on the station asset inventory as of December 31, 2014 compute the expected number of failures for 2015 and beyond. The three ACA models developed in-house in 2014 do not include failure projections or economic analysis. The predicted number of failed units for those equipment classes which do have this feature built into the ACA Model is summarized in Table 54c.

**Table 54c**

| **Station Asset Category** | **Number of Failures Projected for 2014** | **Number of Failures in 2014** |
|---|---|---|
| TS Transformers | 0.28 | 0 |
| MS Transformers | 0.62 | 1 |
| Circuit Breakers | 3.59 | 3 |
| 230 kV Switches | 0.07 | 0 |
| MS Switches | 0.41 | 0 |
| Capacitor Bank Cans* | 6.51 | N/A |
| Station Reactors | 0.13 | 0 |
| Distribution Transformer | 102 | 149 |
| Distribution Switchgear | 58 | 15 |

**There are between 35 and 75 cans in each capacitor bank.*

d) PowerStream has not used the failure curves for the purpose of developing expected reliability performance of the system.

**II-2-Staff-55**

**Ref: E G/T2, 5.3.3 Asset Lifecycle Optimization Policies and Procedures, p. 32, Table 3**

a) Please state the expected number of assets per each asset class that PowerStream has replaced in 2011-2014 and is planning to replace in 2015-2020 within the annual Emergency/Reactive Replacements.

b) Please confirm that these units are in addition to the units planned to be replaced within the other system renewal programs/projects.

**RESPONSE:**

a) Refer to Table 55a.

**Table 55a**

| | | Actuals | | | | Proposed | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
| *Distrubution Lines - Emergency/Reactive Replace Capital* | | | | | | | | | | | |
| a) LIS - Unsheduled Replacement of Failed (end of useful Life) Distrubution Equipment | | 0 | 3 | 1 | 5 | 3 | 3 | 3 | 3 | 3 | 3 |
| b) Non Recoverable replacement of Distribution Equipment due to accident/vandalism | | Not Available | | | | Not Available | | | | | |
| c) Recoverable Replacement of distribution equipment due to Accidents/Vandalism | | Not Available | | | | Not Available | | | | | |
| d) Storm damage - Replacement of distribution equipment due to storm | # of Poles | Please refer to AMPCO 20 - AMPCO 24 for annual Emergency/Reactive Replacements for 2011 to 2014 | | | | 30 | 30 | 30 | 30 | 30 | 30 |
| | # of Transformers | | | | | 18 | 18 | 18 | 18 | 18 | 18 |
| e) Switchgears - unscheduled Replacement of Failed (end of useful Life) Distribution Equpment | | | | | | 37 | 37 | 37 | 37 | 37 | 37 |
| f) Unscheduled Replacement of Failed (end of useful Life) poles, conductors & devices (S) | # of Poles | | | | | 35 | 35 | 35 | 35 | 35 | 35 |
| | # of Transformers | | | | | 270 | 270 | 270 | 270 | 270 | 270 |
| g) Unscheduled Replacement of Failed (end of useful Life) poles, conductors & devices (N) | # of Poles | | | | | 7 | 7 | 7 | 7 | 7 | 7 |
| | # of Transformers | | | | | 87 | 87 | 87 | 87 | 87 | 87 |

b) The units shown in part (a) are in addition to the units planned to be replaced within the other system renewal programs/projects.

**II-2-Staff-56**

**Ref: E G/T2, 5.3.3 Asset Lifecycle Optimization Policies and Procedures, pp. 34-36**

PowerStream states:

> In 2014, PowerStream created its Reliability Model. This model was designed to calculate a five year forward looking reliability projection in terms of SAIDI performance based on the past five years of reliability history and future planned capital system renewal reliability related improvements

Please state whether or not PowerStream has also included potential impacts from programs other than those listed in Table 5 in its reliability projection model If not, please explain.

**RESPONSE:**

DS Plan, Sec 5.3.3, Table 5, Pg. 34-36 lists all the projects and programs that PowerStream believes will have a positive impact and reduce CMI. These are the only projects that have been included in the reliability model.

**II-2-Staff-57**

**Ref: II-2 E G/T2/ p. 4-5, Distribution System Plan Summary and E G/T2/5.3.3/p. 34, pp. 37 – 38**

At the first reference on page 4, PowerStream states that the System Renewal program was designed to "hold system failures, and consequently, reliability, at a constant level (no degradation)."

However, on the next page PowerStream states that:

> There is an expectation that the projects and programs will lead to a modest improvement in reliability to customers as the controllable portion of the System Average Interruption Duration Index ("SAIDI") will decrease as the capital projects/programs and the appropriate Operations & Maintenance spending practices are implemented.

Therefore, the expected outcome of the DSP appears to differ from the original goal of the plan which was to hold the system reliability constant.

At the second reference above, PowerStream states that it created its reliability model in 2014 and that:

> This model was designed to calculate a five year forward looking reliability projection in terms of SAIDI performance based on the past five years of reliability history and future planned capital system renewal reliability related improvements"

At the third reference above, PowerStream provides Figure 8, which is entitled "Total SAIDI, 2015 – 2020 (Predicted)" which shows the improvement in SAIDI during the period of the application.

a) Given the above conclusion of a modest improvement in SAIDI and the significant increase in the capital program that is forecast, please state whether or not PowerStream undertook any cost/benefit analysis of the proposed capital program expenditures as regards their impact on reliability. If PowerStream did undertake any such analyses, please provide them. If not, please state why not.
b) Figure 8 shows a drop in Predicted SAIDI in the 2015 to 2020 period from 69.26 minutes to 59.97 minutes or a drop of about 9.3 minutes. Please state the level of capital expenditures that were on average necessary to achieve a one minute reduction in SAIDI and comment on this result.

c) Please state whether or not the key conclusion arising from the reliability model, specifically that the projects and programs would only lead to a modest improvement in reliability to customers, was discussed with PowerStream's customers during its customer engagement sessions and, if so, what the customer reaction to this conclusion was. If not, please state why not.

d) Please confirm that 2016-2020 DSP was developed to hold system reliability at a constant level in light of the statement referenced above.

e) If this is not the case, please provide a list of 2015-2020 projects which will result in improvements in reliability from existing levels.

f) Please provide a list of 2015-2020 projects that could be reduced in scope or deferred to achieve the original goal of the DSP to hold the reliability at a constant level.

**RESPONSE:**

a) For greater clarity, and referenced to G-AMPCO-6 (q) (EB-2015-003, Section III, Tab 1, Schedule 1, page 129), from the thirteen programs listed on Table 5, four projects are driven based on improving reliability:

1) Worst Performing Feeder (target poor performance of specific feeders);
2) Distribution Automation (improve restoration times);
3) Fault Indicator Program (find the fault faster and improve restoration times); and
4) Storm Hardening (reduce severe storm related outages).

The remaining nine programs listed on Table 5 are driven based on the ACA program and are required to address the aging system. The completion of this work is done to maintain the reliability of the system, not to specifically improve it.

The reliability model includes all of the above programs and captures the anticipated benefits arising from the implementation of the programs.

The cost benefit ($/CMI) for each project has been estimated and can be seen Table Staff-57, attached.

b) As listed in Appendix A, BOMA 11, the total CMI savings are 5,500,758 and the total dollars are $249M resulting in $45.43/CMI for all 13 programs.

For the four projects driven on improving reliability, the total CMI savings are 1,824,365 and the total dollars are $17.9M or $9.85/CMI

The capital programs that are required to address the aging system have a higher $/CMI. This is reasonable as the projects are driven based on the aging system.

It should be noted that the capital programs result in CMI avoidance for future years and not necessarily a CMI savings since the assets are always in a state of aging and degradation.

c) During the presentations made by PowerStream staff as part of the customer engagement sessions, customers were briefed on the programs and were told that PowerStream's investment in system renewal was designed to maintain and/or achieve modest improvement in reliability.

As seen throughout PowerStream's customer engagement consultation, there was general acknowledgement by customers on the planned utility spending for reliability. Although customers do not desire a decrease in reliability, they also do not want rate increases. They generally understood the need to invest in renewal and maintenance of the distribution system.

d) The 2016-2020 DS Plan was generally developed to hold system reliability at a constant level.

e) The four programs that are projected to improve reliability in specific circumstances are listed in answer (a) above.

f) The four programs noted in (a) could be reduced in scope and/or deferred if the goal is to remove reliability improvements. However, PowerStream does not advise that approach.

The Worst Performing Feeders is directed to specific feeders that are poor in reliability compared to other feeders. Similarly, the Distribution Automation and Fault Indicator programs are directed at feeders and areas where there are limited/and or no Automation or fault indicators to enable quick restoration. If these programs are reduced in scope and/or deferred than service reliability imbalances that exist within PowerStream service territory will continue.

The Storm Hardening is a specific program targeted to deal with severe storm conditions, specifically wind, rain and ice. This is a risk issue. The majority of the costs are directed towards rear lot remediation which will result in minimal improvement to reliability on a day-to-day basis. The rear lot assets are at or approaching end-of-life.

The reliability benefit of the four investments offer a high $/CMI return compared to the other 9 programs.

**II-2-Staff-58**

**Ref: E G/T2, 5.3.3 Asset Lifecycle Optimization Policies and Procedures, p. 34, l. 8-9 and Section III, Tab 4, Schedule 1, BOMA-11, Appendix B, Five Year Work Reliability Work Plan 2015-2019, p.18 Table 8**

At the first reference, it is stated that "PowerStream will be striving for targets determined by its Reliability Model".
The second reference is Table 8 "Five year Reliability Improvement Savings.
Please calculate Benefit/Cost ratios for each of the programs in this table for each of the years, by using the following formula including the Customer Interruption Cost used by PowerStream: Cost ($) / (CMI Savings * Customer Interruption Cost)

**RESPONSE:**

The calculations are shown in Table 58 below.

1 **Table 58**

| Five Year Reliability Programs Benefit/Cost Ratios | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Program** | **Program Description** | **Responsibility** | **Program Type** | **2015 362,122 Customers** | **2016 369,822 Customers** | **2017 377,522 Customers** | **2018 385,222 Customers** | **2019 392,922 Customers** | **2020 400,622 Customers** |
| 1 | Worst Performing Feeders (WPF) | Lines | OM&A | 0.02 | 0.02 | 0.02 | 0.02 | 0.07 | 0.00 |
| 2 | Automatic Fault Restoration | SP&S, Ops, Station Sustainment | OM&A | 0.12 | 0.12 | 0.12 | 0.12 | 0.23 | 0.00 |
| 3 | Inspection and Maintenance | Lines, Station Sustainment | OM&A | 0.31 | 0.31 | 0.31 | 0.31 | 0.62 | 0.00 |
| 4 | Wood Pole Replacement | SP&S | Capital | 2.45 | 2.51 | 2.72 | 2.79 | 5.70 | 0.00 |
| 5 | Distribution Automation Switch/Recloser Installation | SP&S | Capital | 0.29 | 0.30 | 0.24 | 0.27 | 0.28 | 0.28 |
| 6 | Underground Cable Replacement and Rejuvenation | SP&S | Capital | 1.20 | 1.24 | 1.32 | 1.36 | 2.80 | 0.00 |
| 7 | Distribution Switchgear Replacement | SP&S | Capital | 0.35 | 0.36 | 0.67 | 0.68 | 0.96 | 0.00 |
| 8 | Submersible Transformer & Vault and Pad Mount Transformer Replacement | SP&S, Lines | Capital | 0.67 | 0.69 | 0.96 | 0.99 | 2.03 | 0.00 |
| 9 | Fault Indicator Program | Lines | OM&A | 0.12 | 0.12 | 0.12 | 0.12 | 0.25 | 0.00 |
| 10 | 44kV Insulators Replacement Program | SP&S | Capital | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 |
| 11 | Mini-Rupter Switch Replacement Program | SP&S | Capital | 1.16 | 1.19 | 1.21 | 1.25 | 2.55 | 0.00 |
| 12 | Ice Storm Hardening | SP&S, Ops, Station Sustainment | OM&A | 0.00 | 0.00 | 0.52 | 0.59 | 1.07 | 0.00 |
| 13 | Rear Lot Supply Remediation | SP&S | Capital | 0.24 | 0.25 | 0.26 | 0.26 | 0.53 | 0.00 |
| Total Yearly Benefit/Cost Ratio of All Programs | | | | 0.43 | 0.54 | 0.49 | 0.52 | 0.94 | 3.74 |

3 Due to limited information on targeted areas CMI savings for 2020 are not estimated.

**II-2-Staff-59**

**Ref: E G/T2, 5.4.1 Capital Expenditure Plan Summary, p. 2, Table 1, Section III, Tab 1, Schedule 1, G-CCC-45, J-CCC-55 and E J/T2/, Appendix 2-K, p. 2**

In its response to G-CCC-45 PowerStream calculated a portion of the capital program that has been and will be completed by internal resources.

PowerStream provides in Appendix 2-K a total number of Non-management employees.

In its response to J-CCC-55 PowerStream explains that "the percentage of … union employees will remain consistent of approximately 60% throughout the rate plan".

Based on the above references, OEB staff has calculated capital budget completed internally over number of non-management employees to determine an annual average level of capital dollars per employee. The four categories in the table below are the year, the capital budget completed internally, the number of non-management employees and the resulting dollars per employee:

2012 - $29M - 415 - $0.07M/employee

2013 - $37M - 429 - $0.09M/employee

2014 - $39M - 439 - $0.09M/employee

2015 - $61M - 454 - $0.13M/employee

2016 - $72M - 449 - $0.16M/employee

2017 - $66M - 445 - $0.15M/employee

2018 - $61M - 445 - $0.14M/employee

2019 - $55M - 446 - $0.12M/employee

2020 - $56M - 444 - $0.13M/employee

a) Please state whether or not PowerStream is in agreement with the above OEB staff calculations and if not, please make any necessary corrections or other adjustments that PowerStream would consider necessary with explanations.

b) Please provide a detailed explanation of how PowerStream is planning to execute suggested capital programs/projects in 2015-2020 which are expected to result in significant increases to $0.12M - $0.16M / employee of internal capital budget execution in 2015 to 2020 compared to actual numbers of $0.07-0.09 achieved in 2012 to 2014.

c) If PowerStream believes that $0.12 - $0.16 of internal capital spending per employee is achievable in 2015-2020, please state whether or not PowerStream agrees that this implies almost 75% labour productivity improvement (average $0.14M/employee in 2015-2020 divided by $0.08M/employee in 2012-2014) in capital spending in its DSP and comment on the feasibility of this improvement.

**RESPONSE:**

a) Yes, the calculation as presented is correct. The calculation, while showing the capital dollars (excluding contract dollars) per non-management employee, not only includes labour, but also includes material, equipment, and external purchase costs, which vary in proportion to one another in any year. This makes it difficult to make an accurate labour productivity conclusion from those calculated figures.

b) As mentioned in the response to question (a), the calculated $/employee figure includes material costs, which can be significant especially if related to the construction of new transformer stations, and also external purchase costs, for example, land for building the new transformer stations. PowerStream does not consider the calculated figures as an accurate measure of labour productivity, nor a measure of its ability to execute the proposed 2015-2020 capital plan.

c) PowerStream believes that its proposed 2015-2020 capital plan in the DS Plan is reasonable, necessary, and entirely achievable. Projects that exceed internally available labour resource will be contracted out. The $/employee measure as presented is not an accurate measure of productivity or productivity improvement.

**II-2-Staff-60**

**Ref: E G/T2, 5.4.1 Capital Expenditure Plan Summary, p. 8, Table 5, 5.4.5 Justifying Capital Expenditures, Appendix A: Project Investment Summaries, Project Code: 102180, 101991, 102968, 103204, 102196, 102009, 102263 and Section IV, T2, TCQ-39, Appendix C**

Please provide financial analysis including Net Present Value calculations for all the IT & Info / Communication Systems projects that exceed the materiality threshold.

**RESPONSE:**

Refer to Appendix Staff 60 – IT Project Investment Summaries, including financial analysis, for the Material Investment IT & Info/Communication System projects. Please note that Net Present Value is not the metric used for the prioritization of PowerStream's 2015-2020 capital plan. PowerStream's projects are evaluated based on a Net Value scoring methodology.

**II-2--Staff-61**

**Ref: EG/T2/ 5.4.2/p. 1**

At the above reference, PowerStream begins its discussion of its customer engagement efforts.

Chapter 2 of the Filing Requirements states, "The RRFE Report contemplates **enhanced** engagement between distributors and their customers to provide better alignment between distributor operational plans and customer needs and expectations." (Emphasis added)

Please describe the differences between customer engagement conducted in preparation for the current application and previous customer engagement. Please explain how customer engagement has been enhanced.

**RESPONSE:**

While PowerStream already has existing customer engagement programs in place, the RRFE explicitly requires distributors to identify **customers' preference and needs** as they relate to the distributor's proposed rate application. The new requirements under the RRFE, beyond how PowerStream currently engages customers to collect feedback for continuous improvement, is what was meant by "enhanced".

PowerStream has never before done an engagement specific to a rate application. Through the specific customer engagement activities, PowerStream was able to consult with: 1,553 customers who completed the Online Primer, 1,202 customers who were surveyed via telephone and 65 customers who participated in the in-person focus groups and workshops. These customers were consulted specifically on their preferences and needs related to the Distribution System Plan.

**II-2--Staff-62**

**Ref: E G/T2/5.4.2/pp.1-13**

At the above reference, PowerStream discusses its customer engagement activities.

Please state whether or not PowerStream's undertakings in this area included providing customers with a range of options in terms of bill increases and related service quality improvements that the bill increases would produce. If PowerStream did undertake such activities, please state where they are discussed in the application. If not, please explain why not and why PowerStream believes that its customer engagement activities were adequate in the absence of this approach.

**RESPONSE:**

No, PowerStream's Customer Engagement activities did not include providing customers with a range of options in terms of bill increases and related service quality improvements.

PowerStream was able to ascertain customer preferences in terms of desired levels of reliability. PowerStream was also able to confirm, by way of the information provided, that our priorities 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 Distribution System Plan.

**II-2-Staff-63**

**Ref: E G/T2, 5.4.3 System Capability Assessment for Renewable Energy Generation, p. 7, l. 10-12**

At the above reference, PowerStream states that "…the Renewable Generation growth rate is expected to peak and begin to decline in 2016 through 2018".

a) Please state why PowerStream believes the Renewable Generation growth rate will peak in 2016.

b) Please state what PowerStream believes will occur after 2018.

c) Please state whether or not PowerStream has a plan if Renewable Generation growth continues through 2016. If yes, please provide.

**RESPONSE:**

a) The forecast is based on the number of Renewable Generation applications received so far, and on the current number of applications in process.

b) PowerStream believes that the Renewable Generation growth rate will likely decline after 2018. This is based on the IESO's program updates currently available.

c) PowerStream has a plan if Renewable Generation growth continues through 2016. PowerStream would retain its contractor resources and proceed with Renewable Generation connections.

**II-2-Staff-64**

**Ref: E G/T2, 5.4.3 System Capability Assessment for Renewable Energy Generation**

Please state the percentage penetration level PowerStream allows for renewable generation on its feeders.

**RESPONSE:**

The penetration level PowerStream allows for renewable generation on its feeders is based on the *Embedded Generation Technical Interconnection Requirements (TIR)* document, section 1.8 (pages 12 & 13).

The TIR document can be found under the following link:

http://www.powerstream.ca/ContentMgr/attachments/PowerStream%20Technical%20Interconnection%20Requirements.pdf

**In addition please see the relevant section below:**

***1.8 Capacity Limitations on Generator Interconnections Feeder Loading Limits***

The capacity for all sections of all feeders, the "feeder limitation," is based mainly on the distance from PowerStream supply station to the Point of Common Coupling (PCC) of the EG Facility. The feeder limitation applies to all EG Facilities connected or connecting to the feeder and considers the rated output capacity of each EG Facility. Any single EG Facility connection can affect the capacity available for all sections of the feeder.

For all sections of the feeder, the total current shall not exceed:

a) 400 Amps for PowerStream feeders operating at voltages 13kV or greater; and

b) 200 Amps for PowerStream feeders operating at voltages below 13kV

**Acceptable Generation Limit at a TS or an MS**

The acceptable generation limit at a PowerStream TS or a PowerStream MS is established by adding together: 60% of maximum MVA rating of the single transformer and the minimum station load.

**1.8.1 Three Phase Generators**

i) The acceptable individual generation limits for three-phase EG Facilities connecting to PowerStream's Distribution System feeders shall not exceed:

a) 1 MW per connection on feeders operating at voltages below 13kV; and
b) 5 MW per connection on 27.6kV feeders supplied via a 44kV:27.6kV stepdown transformer.

ii) The feeder limitation determines the total acceptable three-phase generation allowed for all sections of PowerStream's Distribution System feeders and shall not exceed:

a) 30 MW for feeders operating at 44kV;
b) 19 MW for feeders operating at 27.6kV;
c) 9.6 MW for feeders operating at 13.8kV;
d) 4.3 MW for feeders operating at 12.48kV;
e) 2.9 MW for feeders operating at 8.32kV; and
f) 1.45 MW for feeders operating at 4.16kV.

**1.8.2 Single Phase Generators**

i) The acceptable individual generation limits for single-phase EG Facilities connecting to PowerStream's Distribution System shall not exceed:

a) 150 kW per connection on feeders operating at nominal voltage levels of 13kV or greater; and
b) 100 kW per connection on feeders operating at nominal voltage levels less than 13kV.

Note: While the absolute limits are stated above, the actual acceptable generation limit for specific feeders or TS/MS is determined in the Connection Impact Assessment (CIA).

**II-2-Staff-65**

**Ref: E G/T2, 5.4.5 Justifying Capital Expenditures, p. 4, I. 4-9**

At the above reference, PowerStream states that:

> the 2016 to 2020 investment requirements for the installation of new service infrastructure, as provided in Table 5.4.5.2, are aligned with the increasing trend in the volume of new customer connections and cost escalations for contractors. Refer to Exhibit H, Tab 3 for a detailed discussion on historical and future customer growth.

a) Please provide in a table the actual customer count and customer growth rate and new connections and subdivisions capital spending and growth rate for 2011-2020.

b) If there is a higher growth rate of capital spending compared to the customer growth rate, please provide a detailed explanation for this.

**<u>RESPONSE:</u>**

a) Refer to Table 65a below.

**Table 65a**

| New Connections & Subdivisions | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|
| System Access | Actuals | Actuals | Actuals | Actuals | Forecast | Forecast | Forecast | Forecast | Forecast | Forecast |
| Total Customer counts | 335,935 | 343,344 | 349,797 | 356,461 | 362,543 | 368,663 | 374,990 | 381,372 | 387,845 | 394,508 |
| Customer Growth Rate | | 2.21% | 1.88% | 1.91% | 1.71% | 1.69% | 1.72% | 1.70% | 1.70% | 1.72% |
| New Connects & Sub Capital Spend | $8,080,375 | $15,283,343 | $9,774,346 | $8,790,050 | $13,671,000 | $14,718,000 | $15,801,000 | $16,404,000 | $17,037,000 | $17,674,000 |
| Growth & Inflation Rate | | 89.14% | -36.05% | -10.07% | 55.53% | 7.66% | 7.36% | 3.82% | 3.86% | 3.74% |

b) There is a higher forecasted growth rate of capital spending compared to the customer growth rate in years 2016 and 2017. The capital spending growth rate includes a 3% inflation increase year-over-year for labour, materials and equipment. Based on current activity at the time of this forecast along with positive outlooks from some of the larger developers a 3% growth rate in volume is also included in the area of Layouts and ICI and an additional 250 subdivision lots in both 2016 and 2017.

There is a lower forecasted growth rate of capital spending compared to the customer growth rate in years 2018, 2019 and 2020, with the exception of the

3% that was included for inflation. Based on Regional population and housing information, the forecast in 2018-2020 is expected to level off.

**II-2-Staff-66**

**Ref: E G/T2, 5.4.5 Justifying Capital Expenditures, p. 6 and E G/T2, Appendix A: Project Investment Summaries, Project Code: 102175,**

a) Please provide an end of life criteria for Residential meters

b) Please provide an installation profile by year of "ICON F" meters

c) Please identify a list of privacy data that are at risk with the "ICON F" meters

d) Please provide a list of known cases of actual security breaches related to insufficient encryption data requirements.

e) Please confirm that there are no current regulatory or legislative requirements in relation to residential meters that mandate a replacement of "ICON F" meters. If yes, please provide a reference to the respective documents.

**RESPONSE:**

a) One definition of "End-of-life" (EOL) is that the vendor intends to stop marketing, selling, or sustaining the product. As Sensus no longer manufactures this meter nor provides any active firmware patching, development or support, the meter has reached the end of life criteria. The impact from using the meter that is at end of life is that it will not be able to leverage the improved communication methods of later meters, resulting in greater communication bursts, which ultimately results in increased bandwidth and increased tower gateway requirements or decreased network performance. Additional functionality like improved temperature detection is available to customers with later version of the meter, but not available to current iConF customers.

b) Number of iConF meters installed per year:

| | |
|---|---|
| 2007 | 81,228 |
| 2008 | 50,046 |
| 2009 | 4,726 |

c) Customer's Energy Usage Data - As Data Custodians of customer energy information, PowerStream does not release energy usage data without customer consent, unless the information is aggregated or anonymized. The capability to access the customer's meter, would allow the unauthorized party to gain access to usage data.

d) Encryption by itself, will not guarantee the safeguarding of customer consumption data although encryption is an important component of a defense-in-depth security strategy, which is key to providing Confidentially and Integrity of the information. In 2011/2012 a consortium of 32 Ontario LDC (including PowerStream) engaged a security firm to perform a Security Audit on the Sensus AMI. One of the key findings was that by not enabling encryption, access to meter data transmissions and control actions remains a serious vulnerability. There have been smart meter security breaches reported in the media in jurisdictions like Malta and Puerto Rico. Without additional information it is difficult to conclude if the encryption technology would have limited the extent of the tampering.

e) The replacement of iConF meters is being driven by improved security of customer data and the Operational efficiencies that will be gained by moving to newer meters with enhanced communication, improved WHr reading resolution, and the substantial reduction in deploying staff to check false Tamper and Temperature alarms (PowerStream does not have this issue with iConA meters). PowerStream is not aware of any regulatory or legislative requirements to replace iConF meters, other than the OEB Board Report on Renewed Regulatory Framework for Electricity [dated October 12, 2013 Page 3] stating "…..fundamental principles of good asset management; coordinated, long term planning; and a common set of performance, including productivity expectations."

**II-2-Staff-67**

**Ref: E G/T2, 5.4.5 Justifying Capital Expenditures, p. 6 and E G/T2, Appendix A: Project Investment Summaries, Project Code: 102175, 103637**

a) Please provide historical spending on the Metering program in 2011-2014.

b) There is a gap between the total capital budget and total capital spending of the metering projects that exceeds the materiality threshold, e.g. in 2015 the gap is $1.9M and in 2020 the gap is $1.5M. Please explain.

c) Please provide a count of meter replacements per forecast year for each of these projects: 103637: 4,500 meters total, 102175: 2,000 meters total

d) Please provide an explanation of how metering work will be carried out year over year, specifically considerations with respect to metering crews in the year 2020 when a large spending peak appears in the forecast of project 102175

**RESPONSE:**

a) Please refer to Table 67a below for the historical spending on Metering for years 2011-2014.

**Table 67a**

| System Access | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|
| Metering | 3,146,623 | 2,917,241 | 4,950,164 | 2,406,021 |

b) In accordance with the OEB Chapter 5 Filing Requirements, Section 5.4.5.2 Material Investments, PowerStream has provided additional information for all individual projects/programs that exceeds PowerStream's materiality threshold of $771k. However, the individual details of all the other projects/programs less than the materiality thresholds are not shown, but their capital budgets are included in the totals. The gap identified by OEB Board Staff is simply the difference between the overall capital budget requirements for all metering projects/programs in those years minus the sum of the metering-related Material Investments in those years.

c) The counts of the forecasted meter replacements per year are provided below:
Project 103637 - GS>50 (total population 4,500)
2015 - 300
2016 - 800
2017 - 1000

2018 - 1000
2019 - 800
2020 - 600

Project 102175 – iConF (total population 136,000)
2015 – 2000
2016 – 4000
2017 - 5000
2018 - 8000
2019 - 20000
2020- 40000

d) For GS>50(103637), PowerStream has phased the work to ramp up the effort to 2017/2018, allowing PowerStream to develop issue resolution procedures in the early years and then ramp back down to ensure success in meeting the August, 2020 deadline. For iConF (102175), PowerStream will cluster work as close as possible to maximize efficiency of meter replacements, leveraging contract resources to meet project needs.

PowerStream will be utilising the services of a metering vendor, who has confirmed that they can bring on additional resources to meet project demands. No additional PowerStream staff is envisioned to meet these short term project needs.

**II-2-Staff-68**

**Ref: E G/T2, 5.4.5 Justifying Capital Expenditures, p. 7, l. 4-22 and Appendix A: Project Investment Summaries, Project Code: 101761, 101763**

PowerStream states:

> PowerStream is obligated under the DSC and its Conditions of Service to perform these projects and incur its share of related expenditures. These investments cannot be deferred by PowerStream and must proceed when and where required by the customer. capital contributions toward the cost of all customer demand projects are collected by PowerStream in accordance with the DSC and the provisions of its Conditions of Service. PowerStream's proposed investment expenditures for 2016 to 2020 are based on the historical actual expenditures of projects initiated from 2011 to 2014 with latest forecasts for 2014 and 2015. The forecast investments for 2016 to 2020 are provided below in Table 5.4.5.5.

OEB staff calculates a total average historical spending for the 2011-2015 period for these projects as $0,56M. However, an average spending in Table 5.4.5.5 for 2016-2020 of $1,09M is forecast.

Please provide the justification for the significantly higher forecast compared to the historical level.

**RESPONSE:**

Factors that justify increased activity and budgetary requirements in Customer Initiated Emerging (CIE) Projects include:

- The Ontario Government enacted the Places to Grow Act, 2005, S.O. 2005, c.13. With this legislation PowerStream is starting to see more condos and development with zero set-back. This is leading to encroachment issues with PowerStream's OH pole lines and UG primary cable in some instances.

  Examples:
  - World on Yonge (2013 Condo development) --- Required relocation of OH poles on Yonge St.
  - Mady Development in Barrie (2013 Condo development) --- Required relocation of OH poles on Worsley Street

- In 2016 PowerStream will need to relocate OH poles on Yonge St due to a condo development (Xpression Condo – Torview Development)
- PowerStream is forecasting potential undergrounding requirements of the OH Line on Hwy 7 for the Expo City development on Hwy 7 east of Jane St
- Village Parkway subdivision development in Markham (2014) required hydro relocation from OH to UG

- PowerStream has also seen increased activity due to more Data Centres (TD and IBM data centres in Barrie) and TYSSE (Toronto York Spadina Subway Extension) projects. There are 3 subway stations being built in Vaughan for the TYSSE.

- From 2011 to 2012, there was a 68% increase in CIE Projects

- From 2012 to 2013, there was a 28% decrease in CIE Projects

- From 2013 to 2014, there was a 51% increase in CIE Projects

- From 2016 to 2020, PowerStream is forecasting an annual 10% increase in CIE Projects.

**II-2-Staff-69**

**Ref: E G/T2, 5.4.5 Justifying Capital Expenditures, p. 12, l. 1-6, Appendix A: Project Investment Summaries, Project Code: 100835 and 100851, and EB-2013-0166, 2014 IRM - Response to SEC IRs, Appendix A: PowerStream Asset Condition Assessment Technical Report**

At the first reference, PowerStream states that based on the findings of the Asset Condition Assessment and a detailed analysis of success and costs of the two remediation techniques, it proposes to remediate specific underground cables using the cable injection program at the rate of 100 km/year until 2036 and to replace underground cables at the rate of 30 km/year.

In the project justification for projects 100835 and 100851, rates of 105-115 km/year and 25 km/year for injection and replacement respectively have been selected.

In the ACA report on pages 112 and 116, rates of 47 km/year and 57 km/year for injection and replacement respectively have been determined as optimal.

a) Please reconcile the differences between the proposed rates on page 12, projects 100835 and100851 and optimal rates computed through the ACA.

b) Please provide any risk-based economic justification that was used to determine a new optimal level of underground cable and injection including demonstrating that this level is more beneficial than that defined in the ACA.

c) Please provide the detailed step by step calculation/decision for the final replacement and injection rates. Please provide a risk-based economic justification for the new number.

**RESPONSE:**

a) The cable quantity rates of 47 km/year replacement and 57km/year injection that were indicated in the old ACA Technical Report are no longer valid. The ACA Technical Report has been revised. The most recent version is Appendix BOMA 11, which recommends the new cable quantity rates of 30 km/year replacement and 100 km/year injection.

b) The new cable quantity rates were determined through the “Cable Remediation Program” Report dated February, 2015. The report includes details on:
- Demographics
- Remediation Approach

- Proposed Remediation Program

The report uses different scenarios on success rate and failure probability to obtain the optimum cable quantity rate that would produce an acceptable reliability level in the future. Refer to Appendix Staff-69.

c) Refer to Appendix Staff-69.

**II-2-Staff-70**

**Ref: E G/T2, 5.4.5 Justifying Capital Expenditures, Appendix A: Project Investment Summaries, Project Code: 100835 and 100851, Section III, T2, F-CCC-29, Appendix A, p. 9, 16, and Section III, T4, Schedule 1, BOMA-11 Appendix B, p.26**

In the second reference above (F-CCC-29 Appendix A, p. 9), PowerStream provided a customer satisfaction value justification for the cable remediation program for 2015 and for 2016 that reads as follows:

This project potentially can help avoid outages to 24,290 customers and 2,035,740 CMI.
For 1000 m of cable:
- Frequency of Failure is: 0.5 failure per 1000m of cable per year

For 140,000 m of cable:
- Frequency of Failure Rate is: 0.5 x 140000/1000 = 70 failures per year

According to 2012 Control Room data, there were 123 Cable and Splice failures affecting 42,724 customers and 3,577,118 CMI.
- Average number of customers affected by 1 failure is: 42,724/123 = 347 customers
- Projected number of customers affected by 70 failures is: 347 x 70 = 24,290 customers
- Average CMI for 1 failure is: 3,577,118/123 = 29,082 CMI
- Projected CMI for 70 failures is: 29,082 x 70 = 2,035,740 CMI

In the third reference, the Five Year Reliability Work Plan contained in response to the BOMA interrogatory, PowerStream provided Table 17 with the total CMI savings due to the cable remediation program:

| Year | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|
| CMI Saving | 188,800 | 188,800 | 188,800 | 188,800 | 94,400 | 0 |

In the program description for project code 100835, PowerStream also stated that “there were 103, 123, 133 and 113 cable and splice failures in 2011, 2012, 2013 and 2014 respectively. If not rehabilitated, the cable population will get older and will fail more often to the level that is not manageable by PowerStream and not tolerable by the customers”.

a) Please identify a source for the 0.5 failure per 1000m of cable per year. Please explain in detail how this number was calculated.

b) Please state the number of failures per year that the 2015 and 2016 programs are expected to avoid and contrast this number with the number of cable and splice failures in any of the 2011-2014 years. Please explain any differential.

c) If the actual cable failure rate differs from 0.5 per 1000m of cable, please reconcile the business cases. If this failure rate has been used to justify or forecast any other numbers in the application, please reconcile with these sections of the application as well.

**RESPONSE:**

a) The estimated failure rate of 0.5 failure per 1000m of cable is only applicable for those cable segments that were identified as candidates and were proposed for cable remediation (these cable segments are worse than the general cable population). It should be noted that this failure rate is not applicable for the general cable population.

The estimated failure rate of 0.5 failure per 1000m is considered very realistic and conservative. For example, in a typical subdivision which has 4000m of cable, the estimated annual number of failure is: 4000m x 0.5 failure per 1000m = 2 failure per year, which is realistic considering that PowerStream SAIFI in 2014 is 1.48 (excluding MED) and is 1.71 (including MED).
For those cable projects that were proposed for 2012 and 2013, the actual failure rates are in Table 70a below.

**Table 70a**

| **Cable Injection and Replacement projects in 2012** | **Length of cable addressed (m)** | **Number of failures in 2011** | **Number of failure per km** |
|---|---|---|---|
| (M32) - Markham TS 3 | 2,100 | 3 | 1.4 |
| (V17) - Planchet & Langstaff (Phase 1 of 2) | 4,425 | 3 | 0.7 |
| (V17) - Planchet & Langstaff (Phase 2 of 2) | 3,143 | 3 | 1.0 |
| (Bradford) - Holland - Simcoe - Maplegrove (Phase 1 of 3) | 11,939 | 5 | 0.4 |
| (Bradford) - Holland - Simcoe - Maplegrove (Phase 2 of 3) | 4,000 | 5 | 1.3 |
| (Bradford) - Holland - Simcoe - Maplegrove (Phase 3 of 3) | 501 | 5 | 10.0 |
| (M43) - Don Mills & Steeles (Phase 1 of 5) | 5,332 | 3 | 0.6 |
| (M43) - Don Mills & Steeles (Phase 2 of 5) | 7,859 | 3 | 0.4 |
| (M43) - Don Mills & Steeles (Phase 3 of 5) | 2,393 | 3 | 1.3 |
| (M43) - Don Mills & Steeles (Phase 4 of 5) | 4,217 | 3 | 0.7 |
| (M43) - Don Mills & Steeles (Phase 5 of 5) | 1,244 | 3 | 2.4 |
| (V15) - Dufferin & Steeles (Phase 1 of 2) | 12,630 | 2 | 0.2 |
| (V15) - Dufferin & Steeles (Phase 2 of 2) | 8,807 | 2 | 0.2 |
| (Barrie) - Cundles - Livingstone - Anne (Phase 1 of 2) | 14,957 | 3 | 0.2 |
| (Barrie) - Cundles - Livingstone - Anne (Phase 2 of 2) | 7,945 | 3 | 0.4 |
| (Barrie) - Ferndale - Patterson - Ardagh | 17,437 | 1 | 0.1 |
| (M14-M15) - 9th & 407 Area (2013 portion) | 10,000 | 3 | 0.3 |
| (M49-M50) - Bayview - John - Leslie - Hwy 7 (Inj. - 2013) | 13,451 | 11 | 0.8 |

| | | | |
|---|---|---|---|
| (V08) - Bathurst - Clark - New Westminster - CNR (2013) | 4,384 | 11 | 2.5 |
| (M15) - 9th & 16th Area (2013 portion) | 2,820 | 3 | 1.1 |
| (M44-M45) - Great West Life (Phase 1 of 3) | 31,996 | 7 | 0.2 |
| (M52) - Romfield (Phase 2 of 4) | 5,720 | 16 | 2.8 |
| (M52) - Romfield (Phase 3 of 4 - Stage 1) | 755 | 16 | 21.2 |
| **Average** | | **11** | **0.66** |

Based on the above information, the actual average number of failures per 1000m is 0.66 which is higher than the estimated failure rate of 0.5 that PowerStream uses. As a result, PowerStream will continue to use the estimated failure rate of 0.5 failure per 1000m for the cable segments selected as candidates for cable remediation.

b) The comparison is shown in Table 70b below.

**Table 70b**

| Year | Avoided failure calculations | | | | Actual failures |
|---|---|---|---|---|---|
| **2015** | | Length (km) | Failure rate per km | Failures avoided | In Year 2013 |
| | Injection | 100 | 0.5 | 50 | **133** |
| | Replacement | 25 | 0.5 | 13 | |
| | **Total** | 125 | 0.5 | **63** | |
| **2016** | | Length (km) | Failure rate per km | Failures avoided | In Year 2013 |
| | Injection | 105 | 0.5 | 53 | **133** |
| | Replacement | 25 | 0.5 | 13 | |
| | **Total** | 130 | 0.5 | **65** | |

Based on the above example, the number of failures expected to avoid is about 63-65 failures per year. This number is about one half of the actual number of failures in year 2013 (133 failures).

c) The estimated cable failure rate of 0.5 failure per 1000m is considered realistic and conservative for the targeted cable candidates for remediation, as such, the reconciliation of the business case is not required.

**II-2-Staff-71**

**Ref: E G/T2, 5.4.5 Justifying Capital Expenditures, p. 12, l. 1-6, Appendix A: Project Investment Summaries, Project Code: 100835 and 100851 and EB-2013-0166, 2014 IRM - Response to SEC IRs, Appendix A: PowerStream Asset Condition Assessment Technical Report, p. 112, 114 and 116**

The Asset Condition Assessment Technical Report identified $288 per meter of cable replacement and $72 per meter of cable injection as average costs of the program.

Based on the numbers presented in the Project Investment Summary, OEB staff has calculated the following cost per meter numbers:

| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|
| Cable Replacement (25 km/year) | $11,718,862 | $12,538,684 | $13,607,273 | $14,288,297 | $15,085,861 | $15,340,181 |
| Cost per meter | $469 | $502 | $544 | $572 | $603 | $614 |
| Cable Injection (115 km/year) | $4,024,219 | $4,138,312 | $4,255,465 | $4,375,771 | $4,499,323 | $4,626,219 |
| Cost per meter | $35 | $36 | $37 | $38 | $39 | $40 |

a) Please explain the higher number per meter of cable replacement and the lower number per meter of cable injection.

b) Please explain the 5%-7% increase in cost per meter of cable replacement in 2016-2019.

**RESPONSE:**

a) For Cable Replacement: The original unit cost of $288 per meter cited previously is no longer valid. Refer to Appendix Staff 71 - ACA Technical Report, for the updated estimates.

It was recognized that the unit cost varies widely depending on the complexity and the actual design details at a specific location. At the beginning, PowerStream was hopeful that the unit cost would be low. $288 per meter was thought to be achievable. However, it turned out that the unit costs were higher than estimated. This is one of the reasons that PowerStream decided to replace less and to inject more quantity of cable within the same overall budget funds.

<u>For Cable Injection:</u> The original unit cost of $72 per meter cited previously is higher than the actual unit cost to date. It was recognized that the unit cost varies widely depending on the complexity at a specific location. Factors that affect the cost are:

- Number of splices;
- Number of phases;
- Switching and isolation logistics;
- Cable segment length; and
- Weather.

For the short term, PowerStream anticipates that the unit cost will stay low.

The quantity of 115 km per year is the higher end of the range that PowerStream anticipates achieving if the unit cost would be the lowest extreme of the cost spectrum. In reality, it may turn out that the unit cost will become higher and therefore PowerStream will complete less than 115 km per year.

b) The 5%-7% increase in the proposed budget is not the increase in unit cost. This increase was the result of PowerStream's budget optimization process. The increase is applicable to the whole work program for the year (not unit cost in that year). In the optimization process, the submitted funding may be reduced in one year and deferred (increase) in subsequent years

**II-2-Staff-72**

**Ref: E G/T2, 5.4.5 Justifying Capital Expenditures, p. 16 and 17, l. 13-14 and 1-2, Appendix A: Project Investment Summaries, Project Code: 100867 and EB-2013-0166, 2014 IRM - Response to SEC IRs, Appendix A: PowerStream Asset Condition Assessment Technical Report, p. 107**

On pages 16 and 17 PowerStream states

> …theoretically 2.5% of the poles would require replacement every year…PowerStream's experience has shown that only 1% of the pole population are expected to be found in poor condition every year (over the next five years)…PowerStream proposes to only replace 400 poles per year… .

However, in the ACA report on page 107 the recommendation is to replace 300-400 poles per year.

a) Please provide the details and actual data for recent years that justifies 1% of the pole population being in poor condition. Please specify for both poor condition systems, Health Index and Code A, B, C.

b) If a proposal to replace 400 poles per year was based on the recommendation of the ACA Technical Report, then please justify why was the higher value of 400 selected over 300 poles per year?

PowerStream also states in the Material Investment section (Project Code 100867) the following:

For 1 pole:
- Frequency of Failure is: 0.05 failure per year (1 in 20 years)

For 400 poles:
- Frequency of Failure is: 0.05 failure x 400 = 20 failures.
- Estimated average number of customers affected by 1 failure is = 100 customers
- Estimated projected number of customers affected by 20 failures is: 100 x 20 = 2,000 customers

Duration of interruption = 3 hours per interruption
CMI for 1 pole failure = 100 customers x 3 hour x 60 min = 18,000 CMI
CMI for 20 pole failures = 18,000 CMI x 20 = 360,000 CMI

In addition, PowerStream states:

- O&M Cost for 1 emergency pole failure replacement = $20,000 per failure
- O&M Cost for 20 emergency pole failure replacement = $20,000 x 20 = $400,000

Please provide the actual number of failed poles and total spending for emergency pole failure replacement for each of 2011-2014.

c) Please provide statistical data to support the 0.05 failure rate per year for the poles in poor condition.

**RESPONSE:**

a) On an annual basis, PowerStream conducts pole testing and inspection and uses the latest results to prioritize and select the worst group of poles for replacement. According to the pole testing contractors, pole condition may change drastically over a short time frame, and as such, using the latest testing and inspection results is advisable.

For the next five years, it is estimated that each year, on average, there will be approximately 1% of the population (i.e. approx. 400 poles) to be identified as in poor condition and require remediation.

The most recent pole testing and condition data for 2014 is summarized in Table 72a below.

**Table 72a**

| Number of Poles tested in 2014 | # of poles identified as "Code A" | # of poles identified as "Code B" | # of poles identified as "Poor" as determined by the ACA Model |
|---|---|---|---|
| 10,827 | 4 | 366 | 454 |

From the 2014 pole testing and inspection program, there were 4 poles identified as Code A by the inspectors, 366 poles identified as Code B and 454 poles assessed as poor condition by the ACA Model. The replacements are based on the results of the ACA model which is close to the estimated 400 poles.

b) The number range of 300-400 poles per year cited was from a previous ACA Technical Report (Dated November 27, 2012). The ACA Technical Report has been updated since then. The new version of Appendix Staff 71 - ACA Technical Report (Dated December 31, 2014) recommends 400 poles per year.

The actual numbers of failed poles for emergency pole failure replacement are shown in Table 72b below.

**Table 72b**

| | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|
| Number of failed poles | 8 | 23 | 28 | 38 |

The total annual spending for emergency pole failure replacement for 2011 – 2014 is not available as the pole replacement cost under emergency replacement is not a discrete line item.

c) The estimated failure rate of 0.05 is considered to be reasonable considering the characteristic life of pole is 45 years. It is equivalent to 1 failure in 20 years applicable for the poor condition pole that is selected for replacement. This translates to 20 potential failures applicable for 400 poor condition poles that are selected for replacement. The 4-year average of pole failures (2011, 2012, 2013 and 2014) is: (8 + 23 + 28 + 38) / 4 = 24 failures per year. The 3-year average of pole failures (2012, 2013 and 2014) is: (23 + 28 + 38) / 3 = 30 failures per year. These averages (24, 30) are higher than the 20 potential failures that were estimated from the 400 poles, and as such, PowerStream will continue to use the estimated failure rate of 0.05 failures per year for the selected pole replacement candidates.

**II-2-Staff-73**

**Ref:E G/T2, 5.4.5 Justifying Capital Expenditures, p. 12, 13, p. 15, l. 26-28, 5.3.2 Overview of Assets Managed, p. 46 and Appendix A: Project Investment Summaries, Project Code: 100859**

In various sections of the application OEB staff notes that the following statements are made:

- Total number of distribution switchgears in Poor and Very Poor condition is 180.
- PowerStream is planning to replace 31-36 switchgears a year in the 2016-2020 period.
- In addition, "PowerStream's Emergency/Reactive forecasts expenditures for 2016 to 2020 are based on historical spending during the period of 2011 to 2013".
- Historically, "there were 30, 24, and 28 switchgear failures in 2011, 2012, and 2013 respectively". Average number of failures is 27 per year.

a) Please confirm that all the distribution switchgears in Poor and Very Poor condition will be replaced as part of the Switchgear Replacement program 2015-2020.

b) As there are only 180 switchgears in Poor and Very Poor condition, please provide an explanation as to which switchgears in Fair/Good/Very Good condition will be replaced as part of the Switchgear replacement program.

c) If there is no double counting in both the Switchgear replacement program and Distribution Line Emergency/Reactive program, then an expected number of replaced distribution switchgear per year is 53 (sum of average number of failures (27) and planned replacement volumes (36), Please confirm this number. If this number cannot be confirmed, please provide an explanation and an expected number of the total switchgear failures and replacements in 2016-2020.

**RESPONSE:**

a) Each year, PowerStream prioritizes and selects the worst switchgear units in Poor and Very Poor condition for replacement. Based on the levels, it is estimated that all of the 180 identified units that are in Poor and Very Poor condition will be replaced as part of the Switchgear Replacement Program 2015-2020.

PowerStream's current Inspection and Maintenance cycle is three and six years respectively and we expect that some of the other units (outside of the group of 180) will be identified in the future as Very Poor condition and on ACA result could score worse that the current 180 units. In that case those units may require replacement ahead of some of the 180 units currently identified.

b) PowerStream does not plan to replace units that are in Fair/Good/Very Good condition. PowerStream conducts an annual inspection to monitor the condition of one third of the switchgear population. As time goes on, it is expected that a number of units that are currently in Fair condition will age and become Poor and Very Poor condition and therefore will require replacement in the future. Currently there are 105 units that are in Fair condition. It is expected that some these 105 units will become Poor and Very Poor condition during 2015-2020 period and they will be prioritized for replacement each year

c) There is no double counting between the Planned Switchgear Replacement Program and the Distribution Lines Emergency/Reactive Program. The number in the Planned Program is 36 units per year. The future actual number in the Emergency Program can be estimated but cannot be confirmed as it depends on actual switchgear failures under emergency. It is estimated that the future number of switchgear failures during 2016-2020 is approximately similar to the past (i.e. in the range of 28-30 units per year).

**II-2-Staff-74**

**Ref: E G/T2, 5.4.5 Justifying Capital Expenditures, p. 14, 15 and 5.3.2 Overview of Assets Managed, p. 45**

There are only 38 mini-rupter switches in Poor and Very Poor condition. However, PowerStream plans to replace 60 mini-rupters in 2015-2020.

From the preceding, OEB staff concludes that 22 mini-rupter switches that are planned to be replaced are in Fair/Good/Very Good condition

Please provide an explanation for replacing mini-rupters in Fair/Good/Very Good condition.

**RESPONSE:**

PowerStream does not plan to replace units that are in Fair/Good/Very Good condition. PowerStream conducts its annual inspection to monitor the condition of the Mini-Rupter Switch population and updates the ACA models.

Currently, there are 123 units that are in Fair condition. It is expected that during the 2015-2020 period, several of these units will move into the Poor and Very Poor condition group and they will be prioritized for replacement in those years.

**II-2-Staff-75**

**Ref: E G/T2, 5.4.5 Justifying Capital Expenditures, p. 13, 14 and 5.3.2 Overview of Assets Managed, p. 48**

a) Please provide ACA results for submersible transformers and for pad-mounted transformers respectively.

b) Please provide a risk-based economic justification to replace 65 transformers a year.

**RESPONSE:**

a) PowerStream does not have individual ACA model for submersible transformers and pad-mounted transformers. Both types of transformers are included in the same general distribution transformer model.

The ACA results for all Distribution transformers are shown in Appendix Staff 71.

b) Distribution transformers are a run to failure asset and PowerStream does not use risk-based econometric results to select transformer replacement candidates. The units that are severely over loaded (> 135%) or units that pose imminent safety and environment concerns are prioritized for replacement. Annual inspection results and transformer overloading analysis are used to prioritize the candidates.

Recent review and analysis of inspection data indicates that PowerStream should be replacing greater than 65 units per year.

**II-2-Staff-76**

**Ref: E G/T2, 5.4.5 Justifying Capital Expenditures, p. 17,p. 26, Appendix A: Project Investment Summaries, Project Code: 100859 and Section III, T4/S1, BOMA-11, Appendix B, p. 28**

Power Stream states that

> The Fault Indicator Deployment Plan requires the deployment of a standard, modern fault indicator. Levels of spending remain constant at $500,000 per annum from 2015 through 2017, then increases to $635,000 by 2023. Increased expenditures are to account for inflation and also to budget for the costs of communications infrastructure to connect to SCADA fault indicators at strategic locations.

Therefore, the total investment in 2015-2020 is approximately $3.0M-$3.4M.

In its discussion of Reliability Investments including Distribution Automation on p. 26, PowerStream states

> Other distribution automation initiatives include the installation of SCADA-controlled switches and reclosers, improvements to SCADA infrastructure including communication networks, and distribution feeder fault indicator installation.

In addition, in the Project 100859 Switchgear Replacement Program - 2015 to 2020, PowerStream states “The installation will include associated U/G terminations, fault indicators, and locks”.

In the Five Year Work Reliability Work Plan for 2015-2019, PowerStream forecasts reliability improvement due to the fault indicator installation program:

**Table 20:CMI Savings from the Fault Indicator Program**

| Year | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|
| CMI Saving | 31,500 | 31,500 | 31,500 | 31,500 | 15,750 | 0 |

a) Please confirm that the fault indicators installed in Distribution Automation are in addition to those in the fault indicator replacement program

b) Please provide an explanation for increasing investments in 2018-2023 in the fault indicators and new communication infrastructure in spite of the impact of this initiative decreasing to zero by 2020.

**RESPONSE:**

a) PowerStream only has one fault indicator replacement program. The references cited above refer to the same program.

b) The benefits for 2020 have yet to be estimated and as such are shown to be zero. These will be re-assessed annually with the updates to the plan.

**II-2-Staff-77**

**Ref: E G/T2, 5.4.5 Justifying Capital Expenditures, p. 18**

It is stated that

> PowerStream has approximately 340 Remote Terminal Unit (RTU) automated switches in service… There are a number of existing overhead RTU-controlled switches that are at or close to end-of-life, and will eventually fail to open or close remotely. Through annual inspection and maintenance programs, PowerStream will identify the units that are in the worst condition and require replacement. PowerStream proposes to replace 5 of these RTU-controlled switches each year for the next 10 years.

a) Please provide asset demographics and the latest ACA results for RTU's.

b) Please provide capital spending for the RTU replacement project for each of 2015-2020 years.

**RESPONSE:**

a) The asset demographics and the latest ACA results for Automated Switches are shown in Appendix Staff 71.

b) The spending is shown in Table 77b below.

**Table 77b**

| Asset | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|
| Automated Switch Replacement Budget | $435,912 | $447,130 | $458,595 | $470,301 | $482,308 | $494,628 |

**II-2-Staff-78**

**Ref: E G/T2, 5.4.5 Justifying Capital Expenditures, p. 18 and Overview of Assets Managed, p. 60**

PowerStream states:

> The following voltage conversion projects are included in the Overhead Lines and Assets Planned Replacement program:
>
> • 2015 Elder Mill MS Conversion- Part 2 (3F2);
>
> • 2015/2016 Miller Avenue Markham 27.6kV Conversion;
>
> • 2017 Concord MS Conversion to 27.6 kV - Phase 3;
>
> • 2017 Hwy 27 from Major Mack to Nashville 27.6kV Conversion; and
>
> • 2019 Elder Mill MS Conversion – Part 3.
>
> Detailed justification information for the voltage conversion projects can be found in the Material Investments section of Appendix A to this DS Plan.

In the Reliability including Distribution Automation section on p. 60 of the document PowerStream states that

> This sub-category is for those projects required to sustain the distribution system and ensure reliability. These projects are identified through technical studies or through an identified reliability need. Included in this category are Voltage Conversion Projects, System Reconfiguration Projects, Radial Supply Remediation Projects, Distribution Automation Projects, Reliability Driven Projects and remote Fault Indicator Installation projects.

a) Please provide a page reference or a project code for the voltage conversion projects in the Material Investment section. If not included, please provide a detailed Project Description.

b) Please provide a list of other Voltage Conversion projects that are included in the Reliability including Distribution Automation project. Please provide capital spending amounts for each of 2015-2020 years.

**RESPONSE:**

a) There are no voltages conversion projects in Appendix A that are Material Investments above $771k. All voltage conversion projects in 2015-2020 are less than $771k. For a detailed Project Description, please refer to the response in (b) below.

b) There are no Voltage Conversion projects that are included in the Reliability sub-category. The statement from Section 5.3.2, page 60 of 61 of the DS Plan, that states Voltage Conversion projects are included in the Reliability sub-category, is incorrect. Voltage conversion projects are included in the Overhead Lines, Planned Asset Replace sub-category, which can be found in Section IV, Tab 2, TCQ-39, of Appendix A. Refer to Table 78b below.

**Table 78b**

| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|
| **System Renewal** | **($ 000)** | **($ 000)** | **($ 000)** | **($ 000)** | **($ 000)** | **($ 000)** |
| **Overhead Lines - Planned Asset Replace** | | | | | | |
| Concord MS Conversion to 27.6 kV - Phase 3 | - | - | 481,500 | - | - | - |
| Convert the 8.32kV Ccts into a 27.6kV Cct on Hwy 27 from Major Mack to Nashville | - | - | 400,000 | - | - | - |
| Elder Mill MS Conversion - 8.32kV conductors Removal | - | - | - | - | 169,597 | - |
| Elder Mill MS Conversion- Part 2 (3F2) | 280,062 | - | - | - | - | - |

Detailed Project Description:

1) Convert customers on Concord MS 8.32kV feeder 1F2 (4MVA connected on Bowes Rd and Rivermede Rd) into 27.6kV supply.
2) Convert the 8.32kV circuits into a 27.6kV circuit on Highway 27 from Major Mackenzie to Nashville.
3) Remove Elder Mills 8.32kV feeder conductors where no longer needed for safety and reduce loading on the existing poles.
4) Convert customers on 3F2 into 27.6kV supply or by using step down transformer so that Elder Mills MS can be eliminated after the conversion and 6 km of 8.32kV double circuits can be freed up to be used as 27.6kV circuits.

**II-2-Staff-79**

**Ref: E G/T2, 5.4.5 Justifying Capital Expenditures, p. 25-26 and Appendix A: Project Investment Summaries, Project Code: 100886**

a) Please provide a list of feeders that have been already DA enabled. Please provide for each DA enabled feeder its ranking in WPF in the year prior to the year of installation.

b) Please provide annual reliability data (CMI, FAIDI) for all the DA enabled feeders, 5 years prior to the installation year and after the installation.

c) Please provide an actual average restoration time with DA vs expected 2-5 min.

d) Please a list of feeders that are planned for DA installation in 2015 and 2016. Please provide for each of the feeders its current ranking in WPF.

**RESPONSE:**

a) Table 79a below lists the feeders that are considered 'DA Enabled'. These feeders have had switches installed at various times over the last 25 years and are considered 'DA Enabled' when they achieve at least two normally closed automated switches and one normally open automated switch per feeder. The current WPF Methodology was not created until 2012, and therefore the WPF ranking for these feeders prior to each switch installation is not available.

**Table 79a**

| Sr No | Feeder | Sr No | Feeder |
|---|---|---|---|
| 1 | 10M2 | 30 | 23M6 |
| 2 | 10M4 | 31 | 23M7 |
| 3 | 12M1 | 32 | 24M1 |
| 4 | 12M12 | 33 | 24M3 |
| 5 | 12M5 | 34 | 24M5 |
| 6 | 12M6 | 35 | 24M7 |
| 7 | 12M7 | 36 | 26M1 |
| 8 | 12M8 | 37 | 26M11 |
| 9 | 13M5 | 38 | 26M14 |
| 10 | 153M10 | 39 | 26M18 |
| 11 | 20M1 | 40 | 26M2 |
| 12 | 20M14 | 41 | 26M3 |
| 13 | 20M17 | 42 | 26M5 |
| 14 | 20M18 | 43 | 26M8 |
| 15 | 20M20 | 44 | 27M1 |
| 16 | 20M22 | 45 | 27M4 |
| 17 | 20M23 | 46 | 27M5 |
| 18 | 20M24 | 47 | 27M7 |
| 19 | 20M3 | 48 | 36M1 |
| 20 | 20M8 | 49 | 36M5 |
| 21 | 21M3 | 50 | 36M7 |
| 22 | 21M4 | 51 | 5122M4 |
| 23 | 21M8 | 52 | 5122M8 |
| 24 | 22M1 | 53 | 5122M9 |
| 25 | 22M2 | 54 | 51M2 |
| 26 | 22M5 | 55 | 51M31 |
| 27 | 22M7 | 56 | 55M12 |
| 28 | 23M21 | 57 | D6M2 |
| 29 | 23M5 | 58 | D6M3 |
| | | 59 | D6M6 |

b) Each DA Enabled Feeder has multiple switches, installed in various years, and therefore the specific ‘installation year’ cannot be clearly defined. The requested data is not available.

c) Control room data for DA switching controlled by an automated supervisory management system, FDIR, indicates an average restoration time of less than 1 minute. PowerStream does not track actual restoration times on DA feeders not on FDIR where an Operator performs the switching.

d) Table 79d below lists the Planned DA switch installations for 2015 and 2016, and their current ranking on the WPF list. In addition to the WPF rank, PowerStream considers other factors such as operational needs, bus and feeder loading, or existing DA switches when deciding feeders on which feeders the DA switches will be installed.

**Table 79d**

| Planned DA Install Year | Feeder ID | Current Rank on WPF List | Planned DA Install Year | Feeder ID | Current Rank on WPF List |
|---|---|---|---|---|---|
| 2015 - Planned | 26M15 | 59 | 2016 - Planned | 41M43 | 285 |
| | 10M4 | 40 | | 26M2 | 1 |
| | 23M5 | 46 | | 5122M6 | 18 |
| | 26M2 | 1 | | 41M14 | 239 |
| | 45M4 | 106 | | 41M41 | 139 |
| | 27M7 | 27 | | 41M44 | 149 |
| | 36M1 | 5 | | 41M11 | 277 |
| | 27M1 | 23 | | 24M4 | 3 |
| | 12M6 | 34 | | 27M3 | 8 |
| | 23M8 | 95 | | 24M3 | 21 |
| | 23M26 | 97 | | 138M6 | 23 |
| | 23M24 | 26 | | 23M8 | 95 |
| | 13M4 | 290 | | 80M12 | 61 |
| | 153M4 | 142 | | 20M17 | 191 |
| | 5122M6 | 18 | | 24M2 | 39 |
| | 23M6 | 113 | | 20M4 | 45 |
| | 26M16 | 241 | | 27M12 | 69 |
| | 22M8 | 29 | | 138M7 | 215 |
| | 45M3 | 144 | | 45M4 | 106 |
| | | | | 36M1 | 5 |

**II-2-Staff-80**

**Ref: E G/T2, 5.4.5 Justifying Capital Expenditures, p. 27**

PowerStream states that “Justification on a project basis is included in the material project templates provided in Appendix A”.

Please refer to a project in Appendix A that includes Station Safety and Security.

**RESPONSE:**

There are no Station Safety and Security projects in Appendix A that are Material Investments above $771k. All Station Safety and Security projects in 2015-2020 are less than $771k. A full list of all the Station Safety and Security projects is shown in Table 80 below.

**Table 80**

| System Service | 2015 ($) | 2016 ($) | 2017 ($) | 2018 ($) | 2019 ($) | 2020 ($) |
|---|---|---|---|---|---|---|
| **Station Safety & Security** | 61,515 | 148,655 | 149,074 | 234,084 | 532,992 | 341,384 |
| Arc Flash Mitigation Projects | 11,515 | 11,740 | 12,006 | 26,177 | 26,898 | 27,637 |
| Ground Grid Refurbishments | - | - | - | - | 111,045 | - |
| Sorbweb Oil Containment Systems | 50,000 | 60,000 | 60,000 | 60,000 | 60,000 | 60,000 |
| Station Brand Imaging - Nomenclature, Signage | - | 16,914 | 17,068 | 17,223 | - | - |
| Installation/Retrofit of SWI Video security system TS stations | - | 60,000 | 60,000 | 60,000 | 60,000 | 60,000 |
| Installation of SWI Video security system at MS stations | - | - | - | - | 119,722 | 120,223 |
| Station Security - Station Card Access at Jackson TS, Lazenby 1 and La | - | - | - | - | 41,597 | - |
| Station Security - Station Card Access Cockburn TS, and Walker TS an | - | - | - | - | 41,640 | - |
| Station Vegetation Enhancements at TS's and MS's | - | - | - | 70,684 | 72,091 | 73,524 |

**II-2-Staff-81**

**Ref: E G/T2, 5.4.5 Justifying Capital Expenditures, p. 27**

Smart Grid/RGEN Investments in 2015-2020 are adding up to $6.5M.

Please provide a detailed justification for these investments.

**RESPONSE:**

PowerStream has been a leader in Smart Grid initiatives since 2011 and has successfully demonstrated and piloted many Smart Grid initiatives in the areas of operations-distribution automation, EV technology, Data Analytics, and more recently in the areas of Alternative Energy Sources (microgrids, storage) and Home Technologies.

Smart Grid can be generally defined as the application of technology to produce a more efficient, resilient and reliable distribution system to enable renewable generation and to empower customers with more control over their energy usage.

Due to the rapid advancement of smart grid technology it is challenging to predict and forecast the specific nature and expenditure of Smart Grid projects that PowerStream would undertake in the next years. Hence, the forecast for the 2016 to 2020 Smart Grid Budget is based on previous years' expenditures by focus areas.

Please see Section C, Tab 2, Schedule 1, II-2-Staff-81 Appendix A for detailed information on Smart Grid/RGEN investments (second table) and Smart Grid – Other Investments (first table).

**II-2-Staff-82**

**Ref: E G/T2, 5.4.5 Justifying Capital Expenditures, p. 30-31 and Appendix A: Project Investment Summaries, Project Code: 102263, 102009, 103204, 102968**

PowerStream states for Project 102263 that

> [The MWM] is expected to yield net benefits in terms of productivity and efficiency. These benefits will be quantified as part of the 2014 Planning phase.

In addition, PowerStream also states for the same project the following:

> This [project costing and resource usage] information is used upon project closing but reviewed minimally through project execution. Any scheduling that is done is completed using Excel and/or Microsoft Project. Much of the work lands on the Field/Trades Supervisor's desk and they manually sort through and decide which projects go on which day. There is little communication or information available while a project is executing and resource information is limited and difficult to put together to get insight and control around much of the work that is occurring. Productivity is lost through unnecessary extra field trips, scheduling errors and less than optimal resource allocation.

a) Please identify a go-live date for the MWM. Please explain the need for continuous investment in the system through the five year period.

b) If the projects are minimally reviewed through the project, please identify what elements PowerStream has currently in place to ensure that project cost and resource usage are under control.

c) If the Field/Trades supervisors decide which projects are to be executed on which day, please describe what elements PowerStream has currently in place to ensure that projects are being executed in accordance with their priority.

d) Please provide a rough estimate on the productivity losses through the unnecessary extra field trips, scheduling errors and less than optimal resource allocation.

**RESPONSE:**

a) The initial go-live for this project is planned for Q4 2016.

The deployment strategy is to implement the WFM solution in phases to various work groups over a five-year period. This approach was adopted because of the significant changes associated with introducing a new tool that will impact business processes, roles, and responsibilities in various departments in the organisation. The deployment of the WFM solution will also require its integration to various other IT-based systems in the company, so a phased approach is prudent. The first phase of the deployment will focus on new service connections and unplanned outage work within the Lines area. Subsequent phases will implement the tool for small to large-scale capital projects, maintenance activities, and other work groups such as Metering and Inspections & Locates.

b) PowerStream currently has rigorous review systems in place to ensure that project cost and resource usage are under control. Monthly capital program reports are prepared that track project actuals versus estimates for both labour hours and dollar amounts. Risk indicators in the report identify projects with actual or potential schedule variances. These reports are reviewed at various levels of the organisation to ensure that projects remain on track. Monthly co-ordination meetings are held among Design, Construction, Supply Chain, and System Control personnel to review project status, to plan schedules for upcoming design and construction work, determine an appropriate mix of work to be completed with in-house versus contractor resources, and to develop strategies to mitigate project schedules that may be at risk. Variance reports are produced for projects with significant cost variances compared to estimated cost, and projects with larger variances undergo greater scrutiny. At a more tactical level, there is frequent interaction amongst Construction Managers, Supervisors, and Subforepersons to review resource allocation and project progress to ensure that projects are on track.

Notwithstanding the project controls that are presently in place, current systems require a great deal of manual manipulation and limit PowerStream to tracking and analysing costs and variances at the project level. The WFM solution will allow for reporting at a task level, providing increased ability to identify and address causes of variances. The solution will also provide PowerStream with real-time visibility into resource availability and utilisation as well as the progress of projects, and will reduce the amount of manual work involved in scheduling work and allocating resources.

c) As part of the annual Capital Work Planning process, yearly and monthly spending and project completion targets are set for each program, and priorities are also established. Monthly reports are used to identify the progress of Capital work. At monthly co-ordination meetings, representatives from Design, Construction, Supply Chain, and System Control review the progress of capital work and priorities. This team also sets priorities for upcoming construction work, which impacts design and construction schedules. Frequent reviews are conducted within the Design and Construction teams to ensure that both design and construction priorities are executed in accordance with plan.

d) The WFM solution will realize a number of benefits for PowerStream. Productivity losses through unnecessary extra field trips, scheduling errors, and less than optimal resource allocation are included in the administrative productivity estimates below. Some of the productivity gains will be realized through the following solution functionality:

- Ability to automate work scheduling processes and assign work to business units/teams as a project moves through various phases, eliminating the need to manually execute these tasks;
- Allowing for gaps in a crew's workday to be filled with meaningful work;
- Route optimization, leading to less drive time between jobs and, as a consequence, more productive time;
- Elimination of time-consuming duplicate data entry; and
- Reduction of errors and consequent reduction in time spent tracking and correcting these errors.

Some examples of the benefits of this enhanced functionality are listed below. The associated productivity gains shown are rough estimates of those expected to be attained after the solution is completely implemented by 2020:

- Supervisors spend less time on the manual dispatching and allocating resources, resulting in more emphasis on to tactical planning and performance management (Productivity gain = 15% or $250,000 per year);
- Admin/Technical personnel spend less time coordinating and performing manual data input of documents such as timesheets (15% gain or $60,000 per annum); and
- Gains in field crews productivity will result in a reduction on subcontractor dependency (10% reduction or $800,000 per annum).

**II-2-Staff-83**

**Ref: E G/T2, 5.4.5 Justifying Capital Expenditures, p. 32-33 and Appendix A: Project Investment Summaries, Project Code: 103357, 103358**

a) Please provide the inventory of vehicles/equipment, the current mileage, age and condition assessment result, and current annual maintenance cost for each.

b) Please state the business case used by PowerStream to justify buying new vehicles while acknowledging these vehicles are highly maintainable.

c) Please provide a basis for the selection of a 15-20 year typical useful life for equipment.

d) Please confirm that inflation is included in the 2015-2020 capital spending amounts.

**RESPONSE:**

a) Refer to Appendix Staff 83a – Fleet Inventory.

b) The justification for purchasing replacement vehicles is performed in accordance with the DS Plan, Sec 5.3.1, Pg 17.

c) The basis for the 15-20 year Typical Useful Life for trucks, buckets, and trailers, was the service life comparison report by Kinectrics, ”Asset Amortization Study for the Ontario Energy Board”, issued April 28,2010. The table of all the Typical Useful Lives is submitted as Appendix J-3-1 as found on page 1071 of 4065.

d) The 2015-2020 capital spending amounts for fleet vehicles are based on the best estimates of typical replacement vehicle costs expected in those years, and as such may or may not reflect actual inflation.

**II-2-Staff-84**

**Ref: E G/T2, 5.4.5 Justifying Capital Expenditures, p. 34**

PowerStream states that "Detailed justification information on the tools projects can be found in the Material Investments section in Appendix A of this DS Plan".

a) Please refer to a project in Appendix A that includes Tools.

b) Please explain a growth rate of 25% in Tools in 2020 over 2015.

c) Please explain the inclusion of the following projects in Tools: GoPro cameras, Remote Disconnection Meters ($0.8M in total), Scanner for Addiscott Office, Mobile Tablets.

**RESPONSE:**

a) There are no Tools projects in Appendix A that are Material Investments above $771k. All Tools projects in 2015-2020 are less than $771k.

b) Excluding the purchase of Remote Disconnection Meters in 2018-2020, the overall Tool Budget drops from $570k in 2015 to $465k in 2020, a reduction of 18% over that same time period.

c) These 4 projects, GoPro cameras, Remote Disconnection Meters, Scanner for Addiscott Office, Mobile Tablets, are miscellaneous projects grouped under Tools, because they have been deemed support tools that don't properly fit within IT, Metering or other portfolios.

**II-2-Staff-85**

**Ref: E G/T2, 5.4.5 Justifying Capital Expenditures, p. 35**

At the above reference “Smart Grid - Other Investments” in 2015-2020 are adding up to $6.7M. Please provide a detailed justification for these investments.

**RESPONSE:**

Please refer to PowerStream’s response to interrogatory II-2-Staff-81 for statements regarding PowerStream’s overall plans regarding smart grid implementation.

Please see Section C, Tab 2, Schedule 1, II-2-Staff-81 Appendix A for detailed information on Smart Grid/RGEN investments (second table) and Smart Grid – Other Investments (first table).

**II-2-Staff-86**

**Ref: E G/T2, Appendix A: Project Investment Summaries, Project Codes: 101896,101911, 101887, 101906**

Please explain why the forecast for New Subdivisions is consistently higher than in the 2011-2014 period.

**RESPONSE:**

The forecast for New Residential Subdivisions (project codes; 101887 and 101906) is consistently higher than in the 2011-2014 period primarily due to accounting treatments that were made to reflect regulatory and process changes.

New Commercial Subdivision Developments (project codes; 101896 and 101911) are very difficult to forecast. Historical spend year over year clearly demonstrates volatility in this development sector. Experience has demonstrated that there are no reliable leading indicators that could be used to forecast activity with any degree of accuracy for this type of development class.

**II-2-Staff-87**

**Ref: E G/T2, Appendix A: Project Investment Summaries, Project Code: 101761, 101763**

In each of the project justification sections PowerStream states "The 2015 estimate is based on a 10% annual increase."

OEB staff has calculated the following table of rates of change between years.

| | 2012 vs 2011 | 2013 vs 2012 | 2014 vs 2013 | 2014 Average | 2015 vs 2014 | 2016 vs 2015 | 2017 vs 2016 | 2018 vs 2017 | 2019 vs 2018 | 2020 vs 2019 | Historical Avg vs Forecast Avg |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **101763** | -83.5% | 121.2% | 10.7% | 10.6% | 16.9% | 2.3% | -14.8% | -83.5% | 121.2% | 10.7% | 10.6% |
| **101761** | -64.0% | 142.3% | 19.3% | 17.1% | 16.1% | 14.1% | 75.7% | -64.0% | 142.3% | 19.3% | 17.1% |

Please provide a detailed explanation as to how PowerStream arrived at a 10% annual increase and to which value this increase was applied to derive the 2015 value?

**RESPONSE:**

These two projects are:

- Unforeseen Projects Initiated by the Customer North; and
- Unforeseen Projects initiated by the Customer South.

PowerStream is uncertain how Board Staff determined or calculated the figures in the above table. PowerStream has provided a table below to show the year-over-year differences in spending for Projects 101763 and 101761 as found in Appendix A of the DS Plan. Refer to Table 87 below.

**Table 87**

Historical and Proposed Spending ($)

| Project ID | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|
| 101763 | $ 541,347 | $ (153,875) | $ (115,487) | $ 298,828 | $ 49,387 | $ 109,259 | $ 120,900 | $ 133,723 | $ 156,353 | $ 159,969 |
| 101761 | $ 1,449,123 | $ (692,016) | $ 388,781 | $ 776,335 | $ 279,618 | $ 677,544 | $ 808,502 | $ 946,668 | $ 1,099,428 | $ 1,254,572 |

Year-over-Year Change (%)

| Project ID | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|
| 101763 | | -128% | 25% | 359% | -83% | 121% | 11% | 11% | 17% | 2% |
| 101761 | | -148% | 156% | 100% | -64% | 142% | 19% | 17% | 16% | 14% |

As can be seen in the above table, the year-to-year change can vary from -83% to +142% in the 2015-2020 time period. Due to the amount and timing of capital contributions received for these projects, it is difficult to make meaningful analysis and conclusions of year-over-year changes from the 2011-2014 historical actual amounts.

**II-2-Staff-88**

**Ref: E G/T2, Appendix A: Project Investment Summaries, Project Code: 101800, 101860**

Please describe what factors and values were utilized in the forecasting of storm damaged related expenditures in these two projects.

**RESPONSE:**

As stated in PowerStream's Interrogatory response to G-SEC-26 found in Section III, Tab 1, Schedule 1, Page 203 of 363:

> "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."

**II-2-Staff-89**

**Ref: EB-2013-0166, 2014 IRM - Response to SEC IRs, Appendix B: PowerStream Inc. Corporate Ten Year Capital Plan 2014-2023 and E G/T2, 5.4.4 Capital Expenditure Summary, p. 11**

OEB staff calculates the difference between forecasts in the DSP and the 10 year plan in the table below. Please provide the rationale for the total spend increase of $47M in the DSP.

| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | Total |
|---|---|---|---|---|---|---|---|
| **Total DSP** | $118,399,998 | $132,900,017 | $131,599,752 | $125,499,835 | $125,500,540 | $125,500,071 | $759,400,213 |
| **Total 10 Year Plan** | $130,864,713 | $123,495,236 | $120,349,110 | $98,999,672 | $127,224,247 | $111,151,594 | $712,084,572 |
| **Difference** | $12,464,715 | -$9,404,781 | -$11,250,642 | -$26,500,163 | $1,723,707 | -$14,348,477 | -$47,315,641 |

**RESPONSE:**

The Corporate Ten Year Capital Plan, which was provided in response to Interrogatory G-SEC-15, is the most recent Ten Year Capital Plan, created in June 2013, prior to being superseded by the 2015 DS Plan for the 2015-2020 Custom Rate Application. The difference in spending in the DS Plan compared to the Corporate Ten Year Capital Plan is due to updated, revised, and re-prioritized projects and programs and spending requirements that have resulted in the 18 months following the availability of the Corporate Ten Year Plan.

The material differences can be attributed to new storm hardening/increased rear lot remediation, CIS Systems, smart grid and metering.

**II-2-Staff-90**

**Ref: E G/T2, Consolidated Distribution System Plan and EB-2013-0166, 2014 IRM - TC Undertakings, JT 1.2**

PowerStream's planning utilizes a set of customer interruption costs to quantify the customer's financial impact of outages. In the undertaking, PowerStream presents these outage costs as "Interim".

a) Has PowerStream refined their CIC's since this undertaking?

b) How were the supporting studies selected to reflect a similar operating environment and customers to PowerStream?

c) Is PowerStream aware of any other studies or emerging studies which can improve the estimated CIC?

d) Does PowerStream plan on conducting customer research in order to develop its own CIC's?

**RESPONSE:**

a) PowerStream has not refined the CIC's since the undertaking.

b) The supporting studies were selected because they were considered reputable studies in the electricity industry. There were a wide range of methodology and numerical outage costs cited among the studies. There were no universally accepted method and number range. PowerStream selected a set of CIC numbers that PowerStream considered practical and conservative (middle of the extremes in the spectrum).

c) PowerStream is aware of other studies or emerging studies which can improve the estimated CIC. PowerStream participated in the CEATI (Centre for Energy Advancement through Technological Innovation) DALCM (Distribution Asset Life Cycle Management) Outage Costs project (DALCM Project 50/116). PowerStream was the project monitor and one of PowerStream's Engineers has been invited to co-present the study at the upcoming 2016 Distributech Conference.

d) At this time, PowerStream does not have a plan to conduct customer research in order to develop its own CIC's.

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**II-AMPCO-6**

**Ref: Exhibit G, Tab 2, 5.2.3 Page 5**

Please discuss the number of cable failures per area and/or failure trend that is used to determine the area needs to be included in the cable remediation program.

**RESPONSE:**

Cable failure is only one of many factors that are used to select and prioritize cable remediation work. If an area has 0.5 failures per 1,000m, that area is flagged as a potential candidate for further consideration. Other factors such as failure trend (i.e. cable failure is accelerating), cable age, cable type (strand-fill), cable condition (corrosion), and cable diagnostic testing (tan delta test), are also considered in the prioritization process.

**II-AMPCO-7**

**Ref: Exhibit G, Tab 2, 5.2.3 Page 18**

a) Please discuss if PowerStream has changed its Design and Construction Practices since 2013 and if so, explain how.

b) Please discuss if PowerStream has changed its inspection and maintenance cycles (excluding vegetation management) since 2013 and if so, explain how.

**RESPONSE:**

a) PowerStream has not fundamentally changed the Design and Construction practices since 2013. In terms of design "practices" PowerStream still uses AutoCAD, designing to CSA standards, using wind loading and guying/anchoring spreadsheets, etc. Minor changes to practices that are required for regulatory compliance or the application of new technologies may have occurred.

   Planning loading limits for feeders and TS/MS transformers have not been changed.

b) PowerStream has not changed its inspection and maintenance cycle since 2013 except for vegetation management.

**II-AMPCO-8**

**Ref: Exhibit G, Tab 2, 5.3.2**

Preamble: PowerStream's Asset Condition Assessment provides Health Index Categories for key asset groups under the categories: very poor, poor, fair, good and very good.

a) Please provide the meaning of each Health Index Category: very poor, poor, fair, good and very good.

b) Please explain how each Health Index Category guides the timing of asset remediation needs.

c) Please confirm the health index data provided for each asset corresponds to the end of 2014.

d) Please confirm the party that determined the Health Index Categories for each asset group.

e) Please summarize Kinetrics' role in assessing the condition of PowerStream's assets and indicate the date of the last analysis undertaken by Kinetrics.

f) Please provide Kinetrics' most recent Asset Condition Assessment report.

**RESPONSE:**

a) A score range from 0 to 100 is used for Health Index Categories. A score of 100 is maximum possible score whereas a score of 0 is lowest possible score. The distribution for each category is shown in Table AMPCO-8a below.

**Table AMPCO-8a**

| Health Index Ratings | | |
|---|---|---|
| **Category** | **Score Range** | **Action** |
| Very Poor | 0-30 | For AMPCO-25, Very Poor and Poor are combined as "Poor". These assets are targeted for remediation work. |
| Poor | 31-50 | |
| Fair | 51-70 | These assets are monitored for any change in condition. |
| Good | 71-85 | For AMPCO-25, Good and Very Good are combined as "Good". No action is required. |
| Very Good | 86-100 | |

- Very Poor and Poor: the lowest health index category.
- Fair: the middle health index category.
- Good and Very Good: above average health index category.

b) Health Index Category is a key driver of the asset replacement program for those assets which have health indices. The other factors that are used in determining asset replacement timing are operational requirements, safety concerns, obsolescence, customer service, and coordination with other capital work.

c) The health index data provided for each asset corresponds to the end of 2014.

d) The Health Index Categories for each asset group was determined by System Planning using the ACA models.

e) Kinectrics assisted PowerStream in the creation of the ACA models. PowerStream populated the asset data into the ACA models and ran the ACA models for results. Kinectrics assisted PowerStream in analyzing the results. The last analysis undertaken by Kinectrics was done in April, 2009.

f) Kinectrics' most recent Asset Condition Assessment report is dated April 5, 2009. Refer to Appendix AMPCO-8f – PowerStream Asset Condition Assessment Technical Report Phases 1, 2, and 3.

**II-AMPCO-9**

**Ref: Exhibit G, Tab 2, 5.3.2 Page 44**

Preamble: PowerStream provides age demographics for underground cable.

Please provide the Health Index Distribution for Underground Cable.

**RESPONSE:**

As detailed in the DS Plan, Sec 5.3.3, Fig 1, there is no health index for cables.

**II-AMPCO-10**

**Ref: Exhibit G, Tab 2, 5.3.2 Page 53**

Preamble: PowerStream includes obsolescence as a key driver for capital investment.

Please list the capital programs where obsolescence is a driver.

**RESPONSE:**

The capital projects (programs) that have obsolescence identified as the main driver are as follows:

a) Switchgear Replacement Program, ID 100859
b) Planned Circuit Breaker Replacement Markham TS1&2, ID 101012
c) Station Switchgear Replacement (ACA) 8$^{th}$ Line, ID 102730
d) Station Switchgear Replacement (ACA) Patterson, ID 102732

All four of the above programs are included in the Project Investment Summaries of Appendix A of the DS Plan.

**II-AMPCO-11**

**Ref: Exhibit G, Tab 2, 5.3.3 Page 33**

Preamble: PowerStream indicates many of its Reactive O&M categories are trending upwards by inflationary amounts.

Please provide the inflationary assumptions by year.

**RESPONSE:**

Reactive O&M categories are trending upwards by the budgeted amount of 1%. Primary Cable Faults are budgeted at 3% due to vendor cost escalations. These percentages are projected forward for each year from 2015 – 2020.

**II-AMPCO-12**

**Ref: Exhibit G, Tab 2, 5.3.3 Page 34**

a) Please provide the total number of outages by year for the years 2006 to 2014 and 2015 year to date.

b) Does PowerStream have an outage forecast for 2015 to 2020. If yes, please provide.

c) Please provide the total number of Customer Minute Interruptions for the years 2006 to 2014 and 2015 year to date.

**RESPONSE:**

a) Refer to Table AMPCO-12a below.

**Table AMPCO-12a**

| Total Number of Outages 2006-2015 (Excl: LOS & MED) | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cause | | | Years | | | | | | | | | |
| | Cause Code | Description | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 YTD (June 30, 2015) |
| Controllable | 1 | Scheduled Outage | 368 | 308 | 327 | 289 | 442 | 556 | 616 | 712 | 722 | 436 |
| | 3 | Tree Contact | 81 | 52 | 39 | 38 | 37 | 36 | 97 | 116 | 84 | 32 |
| | 5 | Defective Equipment | 330 | 348 | 316 | 306 | 267 | 290 | 437 | 437 | 501 | 268 |
| | 8 | Human Element | 20 | 42 | 37 | 24 | 18 | 17 | 26 | 40 | 29 | 18 |
| | Controllable Total | | 799 | 750 | 719 | 657 | 764 | 899 | 1176 | 1305 | 1336 | 754 |
| Uncontrollable | 0 | Unknown | 106 | 85 | 75 | 64 | 30 | 31 | 167 | 102 | 112 | 73 |
| | 4 | Lightning | 68 | 29 | 37 | 13 | 17 | 21 | 59 | 28 | 43 | 15 |
| | 6 | Adverse Weather | 68 | 34 | 37 | 32 | 12 | 39 | 101 | 72 | 54 | 13 |
| | 7 | Adverse Environment | 3 | 31 | 11 | 5 | 10 | 15 | 13 | 11 | 30 | 43 |
| | 9 | Foreign Inteference | 203 | 253 | 162 | 145 | 131 | 130 | 321 | 335 | 364 | 127 |
| | Uncontrollable Total | | 448 | 432 | 322 | 259 | 200 | 236 | 661 | 548 | 603 | 271 |
| Total | | | 1,247 | 1,182 | 1,041 | 916 | 964 | 1,135 | 1,837 | 1,853 | 1,939 | 1,025 |

b) PowerStream's forecast is based on the CMI and hence does not have the outage number forecast for 2015 to 2020.

c) Refer to Table AMPCO-12c below.

**Table AMPCO-12c**

| Total CMI 2006-2015 (Excl: LOS & MED) | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cause | | | Years | | | | | | | | | |
| | Cause Code | Description | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 YTD (June 30, 2015) |
| Controllable | 1 | Scheduled Outage | 854,556 | 758,790 | 2,766,762 | 2,052,390 | 1,060,512 | 1,352,886 | 1,468,992 | 2,607,546 | 2,962,308 | 1,196,766 |
| | 3 | Tree Contact | 3,157,926 | 2,053,110 | 2,233,752 | 1,068,414 | 858,798 | 606,216 | 1,036,920 | 2,297,766 | 1,145,286 | 1,073,892 |
| | 5 | Defective Equipment | 7,332,432 | 8,550,150 | 6,205,176 | 8,386,992 | 4,642,806 | 10,175,754 | 10,368,720 | 12,388,716 | 10,310,388 | 5,202,978 |
| | 8 | Human Element | 333,744 | 607,446 | 460,848 | 159,594 | 235,056 | 73,152 | 224,700 | 826,416 | 204,132 | 58,482 |
| | Total | | 11,678,658 | 11,969,496 | 11,666,538 | 11,667,390 | 6,797,172 | 12,208,008 | 13,099,332 | 18,120,444 | 14,622,114 | 7,532,118 |
| Uncontrollable | 0 | Unknown | 699,348 | 1,994,544 | 2,044,176 | 1,143,726 | 223,284 | 237,942 | 547,656 | 229,242 | 645,522 | 333,120 |
| | 4 | Lightning | 1,271,112 | 1,389,048 | 1,596,924 | 538,434 | 682,296 | 1,416,468 | 1,068,534 | 192,120 | 1,724,286 | 610,140 |
| | 6 | Adverse Weather | 6,397,668 | 2,281,134 | 2,188,914 | 4,695,570 | 168,054 | 3,739,602 | 3,477,600 | 1,994,994 | 861,234 | 25,740 |
| | 7 | Adverse Environment | 58,002 | 38,430 | 384,330 | 130,638 | 268,488 | 94,056 | 404,040 | 85,428 | 3,418,650 | 4,203,174 |
| | 9 | Foreign Inteference | 2,021,334 | 2,931,270 | 2,726,592 | 953,448 | 2,268,282 | 2,350,344 | 2,639,160 | 3,364,140 | 3,619,590 | 1,688,010 |
| | Total | | 10,447,464 | 8,634,426 | 8,940,936 | 7,461,816 | 3,610,404 | 7,838,412 | 8,136,990 | 5,865,924 | 10,269,282 | 6,860,184 |
| Total | | | 22,126,122 | 20,603,922 | 20,607,474 | 19,129,206 | 10,407,576 | 20,046,420 | 21,236,322 | 23,986,368 | 24,891,396 | 14,392,302 |

**II-AMPCO-13**

**Ref: Exhibit G, Tab 2**

For rate base funded projects, please provide a table that summarizes the capital contributions for each OEB category (System Access, System Renewal, System Service, General Plant) for the years 2010 to 2014 actuals, 2015 year-to-date and 2015 forecast to year-end, and forecast for 2016 to 2020.

**RESPONSE:**

Refer to Table AMPCO-13 below for a summary of capital contributions for the period 2011-2020. Due to the merger between PowerStream and Barrie Hydro in 2009, meaningful figures for year 2010 are not able to be produced.

**Table AMPCO-13**

| OEB Category | 2011 | 2012 | 2013 | 2014 | 2015 Proposed | 2015 June 30 Actual | 2015 YE Forecast | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| General Plant | 1,444 | 3,360 | - 3,360 | - | - | - | - | - | - | - | - | - |
| System Access | 29,560,811 | 30,943,103 | 19,271,865 | 22,876,343 | 18,323,000 | 8,214,000 | 18,701,000 | 21,876,545 | 22,812,236 | 23,832,651 | 23,802,293 | 25,322,604 |
| System Renewal | 640,200 | - 10,721 | - 22,055 | - 8,188 | - | 21,000 | - | - | - | - | - | - |
| System Service | 65,516 | - 8,883 | 2,105,821 | 79,232 | - | - | - | 137,311 | 110,492 | - | - | - |
| Grand Total | 30,267,971 | 30,926,860 | 21,352,271 | 22,947,387 | 18,323,000 | 8,235,000 | 18,701,000 | 22,013,856 | 22,922,728 | 23,832,651 | 23,802,293 | 25,322,604 |

**II-AMPCO-14**

**Ref: Exhibit G, Tab 2**

Please complete the table below to update 2015.

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|
| Opening WIP | | | | | | | | | |
| Capital Expenditures | | | | | | | | | |
| Closing WIP | | | | | | | | | |
| **In-service Additions** | | | | | | | | | |

**RESPONSE:**

PowerStream is forecasting the same 2015 capital expenditures and the same 2015 closing WIP. There have been no changes from the information filed. Please see Section II, Tab 1, Exhibit G, Tab 2a, page 1 “Table 2:In-Service Additions”.

**II-AMPCO-15**

**Ref: Exhibit G, Tab 2, 5.4.5 Page 19**

Preamble: PowerStream indicates that according to meteorologists, the frequency and severity of storms is expected to become more common in the future.

Please provide a reference to support this statement.

**RESPONSE:**

Refer to TCQ-2-G-SEC-19, Appendix B, sections 1.2.2, 1.2.3, 1.2.4 and 1.2.5 within the EB-2015-003 May 22, 2015 application.

**II-AMPCO-16**

**Ref: Exhibit J, Tab 3, Page 2**

Preamble: Service life comparison with the Kinectrics report ,"Asset Amortization Study for the Ontario Energy Board", issued April 28,2010 is provided as supplementary information in electronic Appendix J-3-1 (Fixed Assets Useful Life Schedule). For several asset categories the proposed useful life is outside the range of Min, Max Typical Useful Life (TUL) as determined by Kinetrics.

a) Please identify any changes in the proposed TUL of assets since PowerStream's last Cost of Service Application (EB-2012-0161).

b) Please provide the analysis that supports the proposed changes.

**RESPONSE:**

a) There have been no changes to the useful life used to amortize fixed assets since PowerStream's last Cost of Service Application (EB-2012-0161).

Two new capital asset accounts were added since the 2013 COS rate application:

1) Account 1927 - Customer information System ("CIS") software - TUL = 10 years
2) Account 1846 - Underground primary Cable Injection - TUL = 20 years

b) CIS software was added as a separate software class. PowerStream has implemented a new Oracle based customer service and billing system that has a longer useful life than other software programs that are currently in use by PowerStream. The extensive magnitude, scope and functionality of the CIS software would allow this application to have an expected useful life of up to 10 years before a major upgrade is required or the software will be replaced. This estimate is based on discussions with other organizations using similar software.

The underground cable injection asset class was added in 2014. PowerStream added this new class as injected cable has a different expected useful life than replaced cable. Based on the warranty and technical supporting information provided by the supplier the expected useful life of injected cable is 20 years.

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**II-Energy Probe-6**

**Ref: Exhibit A, Tab 1 & EB-2014-0002 Settlement Proposal (Horizon Utilities Corporation) dated September 22, 2014**

PowerStream has indicated that the application is on a standalone basis regardless of whether or not the potential merger proceeds. Based on this standalone basis, please answer the following questions.

a) Is there anything that would preclude PowerStream from adopting the earnings sharing mechanism as described on pages 29-30 of the Horizon Settlement Proposal that was accepted by the Board? If yes, please explain.

b) Is PowerStream willing to accept such an earnings sharing mechanism? If not, please explain why not.

c) Is there anything that would preclude PowerStream from adopting the efficiency adjustment mechanism as described on pages 31-32 of the Horizon Settlement Proposal that was accepted by the Board? If yes, please explain.

d) Is PowerStream willing to accept such an efficiency adjustment mechanism? If not, please explain why not.

e) Is there anything that would preclude PowerStream from adopting the capital investment variance account as described on pages 32-35 and Appendix L of the Horizon Settlement Proposal that was accepted by the Board? If yes, please explain.

f) Is PowerStream willing to accept the capital investment variance account? If not, please explain why not.

**RESPONSE:**

a) Theoretically no, but this could be an issue for settlement or for a hearing. PowerStream might also consider a variation to the Horizon earnings sharing mechanism.

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

c) Theoretically no, but this could be an issue for settlement or for a hearing. PowerStream might also consider a variation to the Horizon efficiency adjustment mechanism.

d) Please see the response to II-Energy Probe-6-c.

e) Theoretically no, but this could be an issue for settlement or for a hearing. PowerStream might also consider a variation to the Horizon capital investment variance account.

f) Please see the response to II-Energy Probe-6-e.

**II-Energy Probe-7**

**Ref: Exhibit A, Tab 1, page 3**

a) Please confirm that the WCA annual adjustment for the cost of power is limited to the cost of power rates and there would be no adjustment in the cost of power related to volumes (kWh's).

b) Please what is included in tax rates (e.g. CCA changes, tax credits, corporate rates, etc.)?

c) Do changes in the cost of capital include the impact of any changes in the deemed capital structure? If not, please explain why not.

**RESPONSE:**

a) Confirmed.

b) Please refer to Section III, Tab1, page 294 of the Application for the response to J-Energy Probe-41.

c) Please refer to Section III, Tab 1, page 321 of the Application for the response to K-Energy Probe-45.

**II-Energy Probe-8**

**Ref: Exhibit A, Tab 1, page 4**

In part (b) an example is given wherein it states that if the Board's inflation rate is greater than 4.0% (when the forecast used was 2.0% for 2017), then there would be an adjustment to the revenue requirement for 2017 in preparing the 2017 draft rate order. If the inflation rate was 4.5% as determined by the Board for 2017 as compared to the forecast of 2.0% used and the 200 basis point threshold was approved by the Board:

a) Would the full incremental inflation rate of 250 basis points be used in the adjustment or would the incremental inflation rate in excess of the threshold be used (i.e. 50 basis points).

b) What components of the revenue requirement would the incremental inflation rate be applied to?

**RESPONSE:**

a) PowerStream's proposal is that it would manage within the threshold amount and if the threshold amount is exceeded, the incremental inflation rate in excess of the threshold would be used.

b) The incremental inflation rate would be applied to the OM&A portion of revenue requirement.

**II-Energy Probe-9**

**Ref: Exhibit A, Tab 1, pages 4-7 & Report of the Board - Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach dated October 18, 2012**

Please explain how PowerStream's proposal for an inflation threshold adjustment and/or adjusting the current Custom IR plan are consistent with the RRFE where the Board has stated that it 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?

**RESPONSE:**

Please see the response to interrogatory VI-Staff-98 (c).

**II-Energy Probe-10**

**Ref: Exhibit B, Tab 1, page 1 & Section III, Tab 3, Schedule 1, BOMA-9**

The evidence states that the new Vaughn transformer station will be going into service in the spring of 2017 to provide needed capacity and has no impact in 2016. Please reconcile this statement with the response to BOMA-9 that PowerStream has included $3.2 million in land to be used for this TS in rate base in 2014.

**RESPONSE:**

Respectfully, the requested reconciliation mixes up two different regulatory principles. The regulatory principle in the case of the Vaughan transformer station is the in-service date. The regulatory principle in the case of the purchased land is <u>used or useful</u>. PowerStream purchased the land in the spring of 2014 specifically to accommodate building the Vaughan transformer station. In 2014 the land was deemed suitable for the construction of the transformer station. This renders the purchased land as <u>useful</u> and on that basis it was added to the 2014 rate base.

**II-Energy Probe-11**

**Ref: Exhibit E, Tab 1 & Section V, Tab 1, Schedule 1 & Section III, Tab 1 Schedule 1**

a) Please provide an updated version of Table 1 (Exhibit E, Tab 1) that reflects the corrections and updates noted in Section V, Tab 1, Schedule 1.

b) Please provide an updated version of Table 1 provided in the response to E-Energy Probe-5 (Section III, Tab 1, Schedule 1) that reflects the corrections and up-dates noted in Section V, Tab 1, Schedule 1.

**RESPONSE:**

a)

**Table II-EP-11-1: Revenue Requirement and Revenue Sufficiency (Deficiency)**

| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|
| Rate Base | $984,151,745 | $1,008,057,574 | $1,091,776,553 | $1,173,034,221 | $1,244,720,821 | $1,314,691,292 |
| Cost of Capital | 5.85% | 6.02% | 6.08% | 6.10% | 6.10% | 6.10% |
| Return on Rate Base | 57,569,865 | 60,718,438 | 66,415,705 | 71,505,838 | 75,875,711 | 80,140,972 |
| OM&A Expenses | 92,557,500 | 96,216,191 | 101,808,409 | 103,724,061 | 106,108,457 | 108,228,344 |
| Amortization Expense | 41,837,900 | 47,373,722 | 51,461,387 | 54,147,586 | 57,006,212 | 60,144,283 |
| PILs | (4,866,518) | (4,694,260) | 3,357,525 | 4,869,126 | 5,960,608 | 6,198,041 |
| Service Revenue Requirement | $187,098,747 | $199,614,091 | $223,043,025 | $234,246,611 | $244,950,989 | $254,711,640 |
| LESS: Revenue Offsets | 12,487,117 | 12,590,603 | 12,718,312 | 12,816,681 | 12,938,953 | 13,069,086 |
| Base Revenue Requirement | $174,611,630 | $187,023,489 | $210,324,714 | $221,429,930 | $232,012,036 | $241,642,555 |
| Revenue at Current Rates | 160,819,027 | 161,792,522 | 162,498,923 | 163,366,863 | 164,347,366 | 165,701,810 |
| Revenue Deficiency | ($13,792,604) | ($25,230,966) | ($47,825,791) | ($58,063,067) | ($67,664,670) | ($75,940,745) |

b)

**Table II-EP-11-2: Revenue Requirement and Revenue Sufficiency (Deficiency)**

| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|
| Rate Base | $984,151,745 | $1,008,057,574 | $1,091,776,553 | $1,173,034,221 | $1,244,720,821 | $1,314,691,292 |
| Cost of Capital | 5.85% | 6.02% | 6.08% | 6.10% | 6.10% | 6.10% |
| Return on Rate Base | 57,569,865 | 60,718,438 | 66,415,705 | 71,505,838 | 75,875,711 | 80,140,972 |
| OM&A Expenses | 92,557,500 | 96,216,191 | 101,808,409 | 103,724,061 | 106,108,457 | 108,228,344 |
| Amortization Expense | 41,837,900 | 47,373,722 | 51,461,387 | 54,147,586 | 57,006,212 | 60,144,283 |
| PILs | (4,866,518) | (4,694,260) | 3,357,525 | 4,869,126 | 5,960,608 | 6,198,041 |
| Service Revenue Requirement | $187,098,747 | $199,614,091 | $223,043,025 | $234,246,611 | $244,950,989 | $254,711,640 |
| LESS: Revenue Offsets | 12,487,117 | 12,590,603 | 12,718,312 | 12,816,681 | 12,938,953 | 13,069,086 |
| Base Revenue Requirement | $174,611,630 | $187,023,489 | $210,324,714 | $221,429,930 | $232,012,036 | $241,642,555 |
| Revenue at Current Rates | 160,819,027 | 161,792,522 | 187,844,889 | 211,294,253 | 222,672,625 | 233,847,810 |
| Revenue Deficiency | ($13,792,604) | ($25,230,966) | ($22,479,825) | ($10,135,677) | ($9,339,411) | ($7,794,745) |

**II-Energy Probe-12**

**Ref: Exhibit F, Tab 1**

a) Please confirm that the productivity savings in Table 4 over the 2016 through 2020 period is about $5.4 million.

b) Please provide a version of Table 4 that replaces the 2014 figures with actual 2014 OM&A expenses along with the updated inflation adjustments, customer growth adjustments and incremental new costs and provide the total productivity savings over the 2016 through 2020 period.

**RESPONSE:**

a) Confirmed.

b) Please note that Table 4 does contain the actual 2014 OM&A expenses so that no update is required. Please refer to Section III, Tab 1, page 80 of the Application for the response to F-EP-6 discussing the inflation and customer growth adjustments.

**II-Energy Probe-13**

**Ref: Exhibit F, Tab 2, page 3**

The evidence states that PowerStream is experiencing different operating conditions than typical in the industry and that this may not be fully reflected in the historical data used in the PEG model.

a) Please provide more detail on the different operating conditions experienced by PowerStream.

b) How does PowerStream know that other distributors are not facing the same operating conditions, given the limited knowledge that distributors appear to have of the characteristics of other distributors?

c) Has PEG confirmed that this is a legitimate limitation of the PEG model in forecasting future results?

d) Please explain how the PEG model can provide reasonable forecasts for PowerStream when the model needs historical data from numerous distributors in order to estimate robust coefficients and cannot incorporate such data from other distributors over the forecast period against which PowerStream is being evaluated.

**RESPONSE:**

a) PowerStream believes that its current and planned capital and OM&A spending represents different operating conditions than those reflected in the historical industry data used in the benchmarking model. There are three main differences:

1) Requirement for significantly greater capital spending on sustainment;

2) Replacement of a thirty year old customer billing system to meet increasing requirements and customer expectations; and

3) The need to “harden” the distribution system to withstand the increasing frequency and intensity of storms.

These are discussed further below:

1) The need for significantly higher levels of capital spending on sustainment is a relatively recent development for PowerStream and it is significantly higher over the custom IR plan term than the historical period used in the PEG Model.

The increased sustainment spending is the result of the considerable work that PowerStream has done in conducting asset condition assessments and developing a strong asset management program. Based on this work, PowerStream has confirmed the need to undertake higher levels of sustainment spending to maintain reliability and prevent deterioration of its distribution system. PowerStream has carefully assessed what must be done and included the necessary work in its capital plan.

The costs of the distribution assets in Residential subdivisions, prior to the year 2000, were fully paid for by developers. For assets fully paid by developers there are no capital costs or depreciation in rates. PowerStream must replace these assets at its cost and recover those costs through rates.

2) PowerStream recently replaced a thirty year old customer billing and information system ("CIS") with a new Oracle Customer Care and Billing System that is capable of meeting the new and emerging requirements and greater customer expectations. This required a substantial capital investment and represents a significant change in its level of costs.

3) There are significant net incremental new costs related 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. (See Section II, Tab 1, Exhibit J, Tab 1 for more information on the OM&A cost drivers. See Section II, Tab 1, Exhibit G, Tab 1 and the Distribution System Plan for more details on the capital costs related to the new CIS and system hardening).

b) Due to the location of PowerStream's southern service area in York Region close to the City of Toronto, York Region was one of the earlier places to see large scale suburban development such as residential subdivisions. It is reasonable to conclude that PowerStream needs to replace these subdivision assets earlier than many other distributors where this type of development came much later.

PowerStream has a well-developed asset assessment and management system. PowerStream started its asset assessment work with Kinetrics in 2007. Due to this early start PowerStream believes that is further along than many other utilities in recognizing and starting to address the sustainment issues.

Based on these factors, it is reasonable to conclude that PowerStream's capital spending requirements for sustainment are not captured by the historical data used to create the parameters in the PEG model.

Similarly, PowerStream believes it has been running the longest in-service CIS system in the distributor community. Replacing such an old CIS system that has been in-service for 25 years has required a significant jump in the costs related to the CIS system. Other utilities who have upgraded their CIS systems more frequently over the years will not have the same jump in costs.

The estimates generated by the econometric cost model should be interpreted as the predicted costs of a typical or average distributor facing similar output demands, input prices, and business conditions. However, individual circumstances can vary and may not be adequately captured by a model common to the industry as a whole.

c) PowerStream did not consult with PEG regarding the use of the PEG model in forecasting future trends.

PEG notes limitations of the model within its "*Productivity And Benchmarking Research In Support Of Incentive Rate Setting In Ontario: Final Report To The Ontario Energy Board, November 5, 2013, Pacific Economics Group*" ("PEG Report"). The following are some of the limitations mentioned in the PEG Report:

"*Our TFP and benchmarking studies can be updated and refined over time to accommodate new data from the industry or consider different business condition variables, including measures of service reliability such as SAIDI and SAIFI. Overall, PEG believes the methodologies used strike a reasonable balance between rigor, objectivity and feasibility (given the data constraints), while simultaneously developing empirical techniques that can provide a foundation for effective IR applications for Ontario in the future."* (PEG Report pages 6-7)

*"Another possibility is that <u>there are cost pressures for a sizeable portion of the industry due to company-specific factors</u>, [underline added] rather than industry-wide policies, but it is difficult to capture these company-specific pressures in measurable business condition variables."*(*PEG* Report, p. 60)

*"With respect to the share of a distributor's customers that was added over the last 10 years, the variable is designed to proxy recent growth and the age of distribution systems. All else equal, serving a relatively fast-growing territory requires a greater amount of more current capital additions. These investment pressures could put upward pressure on costs. Our*

*model shows that a 1% increase in this variable increases distribution costs by 0.017%."* (PEG Report, p. 60)

With respect to the proxy for the age of distribution systems, PowerStream notes that it is designed to capture the impact of capital requirements for new growth but does not address the issue of the need for sustainment particularly in cases where previously significant capital had been contributed by developers.

PowerStream believes the PEG econometric model is a worthwhile tool used by the Board but results must be considered in the context of the actual situation of a specific utility, the inherent limitations and the degree of accuracy that can be expected from the use of an econometric model.

The degree of accuracy of the econometric model is recognized by the Board's use of ranges for the stretch factor assignments. PowerStream is in group 3 which is defined as actual cost within ±10% of predicted cost. PowerStream notes that using the PEG model to benchmark its forecasts produces results within this same band.

PowerStream believes that over time as the PEG model evolves, more current data is used and work continues on ensuring the quality of data, that PowerStream's actual results will be more favourable than the current forecast from the model.

d) PEGs benchmarking model is based on econometrics. Distributor cost in this model is estimated as a function of business conditions faced by each distributor. The business conditions required include measures of LDC output and input prices for capital and OM&A. The parameters of this model establish the relationship between each business condition and distributor cost and they define their importance on cost. Once estimates of the importance of each factor is on cost is determined, a prediction equation is determined through the regression results of the model. The resulting prediction is the level of cost a typical distributor in Ontario would have if they had faced that particular set of factors.

The econometric model will generate parameters that best fit the sample used to estimate the model. The cost predictions that come out of the model, therefore, create an average performance standard.

On May 7, 2015, The OEB has published an enhanced benchmarking Spreadsheet Model and a User's Guide for electricity distributors in relation to the implementation of improvement initiatives for the 2014 Electricity Distributor Scorecard. The Model incorporates a "Forecasting" sheet that contains the formulas necessary to forecast future benchmarking results. This forecasting capability of this tool is utilized in the same manner as PowerStream has in this Application.

PEG notes limitations of the model within its *“Spreadsheet Model for Benchmarking Ontario Power Distributor – User Guide”* (“User Guide”). The following are some of the limitations mentioned in the User Guide:

*“The escalation method is reasonable to obtain 2014 values, but it is not likely that this method would produce accurate values for each year of a multi-year forecast period. It is therefore recommended that anyone wishing to produce forecasts beyond 2014 enter the values for each year separately based on their own forecast models.”* (User Guide, p.27)

PowerStream has entered the values for each year separately as described in the Application in Section II, Tab 1. Exhibit F, Tab 2 and Section III, Tab 1, page 84, F-Energy probe 9.

**II-Energy Probe-14**

**Ref: Exhibit G, Tab 2a**

a) Please update Tables 2 and 3 to reflect the most recent year-to-date information available for 2015, along with the current forecast for the remainder of 2015. Please explain any changes to 2016 or future years that result from the change in 2015 due to deferred projects or accelerated projects or any other change.

b) Based on the response to part (a), please provide updated continuity schedules for 2015 through 2020. Please also provide an electronic copy of the updated continuity schedules.

**RESPONSE:**

a) There are no changes to the filed capital expenditure plans for 2015. Consequently there are no updates required to Exhibit G, tab 2a fixed asset amounts.

b) This is not required based on the response to part (a) above. Note that there are changes from 2016 onwards related to the Board's new policy requiring Residential customers to be billed monthly starting in 2017. See Section A, Tab 1, Schedule 1, Application Update Summary for more information.

**II-Energy Probe-15**

**Ref: Exhibit G, Tab 4**

a) Please update the cost of power for 2016 to reflect the April 20, 2015 Regulated Price Plan Price Report for the RPP and non-RPP prices, along with any required changes to the transmission, low voltage, wholesale rates, etc. that are known as of the current time.

b) Please provide an electronic version of Appendix G-4-1 that shows the 2016 calculation as requested in part (a), along with the forecasts for 2017 through 2020.

**RESPONSE:**

a) The Cost of Power for 2016 has been updated to reflect the following changes:
- Uniform Transmission Rates: Rate Order issued by OEB on January 8, 2015;
- Hydro One Distribution's Sub-transmission rates: Rate Order issued by OEB on April 23, 2015;
- RPP and non-RPP price: Regulated Price Plan Price Report issued on April 20, 2015 by OEB;
- Updated Load forecast: Based on updated load forecast as per III-VECC -19 (c);
- The RPP/non-RPP kWh split: Based on 2014 actual consumption split; and
- Hydro One related charges: Based on updated historical average ratios over the period from 2012 to 2014 including :
    - Total system demand to total energy purchase
    - Transmission line connection demand to system demand
    - Transmission transformation connection demand to system demand
    - Low voltage demand to system demand

b) Please refer to II-EnergyProbe-15-Appendix A for updated electronic version of cost of power calculation as requested in part (a), along with the forecasts for 2017 through 2020.

**II-Energy Probe-16**

**Ref: Exhibit H, Tab 4**

a) Please explain the difference in total customer counts shown in Tables 4 and 7.

b) Please provide a table in the same level of rate class detail as shown in Table 7 that shows for each class, the forecasted number of customers/connections by month for each month in 2015. Please also add a line for each rate class that shows the actual number of customers in each month for which actual data is now available.

## RESPONSE:

a) To clarify, this IR indeed refers to the difference in total customer counts shown in Table 5 and Table 7 (Exhibit H, Tab 4). Please see the table below for reconciliation on the difference shown in these two tables.

Table 5 shows total customer counts over the forecast period, excluding customer connections; whereas Table 7 shows billing determinants which can be either customer counts or connections. Since Street Lighting and Sentinel class are billed based on number of connections, Table 7 includes the connections forecast, instead of customer counts, for these two rate class.

| Rate Class | Unit | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|---|---|
| **Residential** | Customer Counts | 322,324 | 327,907 | 333,673 | 339,480 | 345,362 | 351,406 |
| **GS<50kw** | Customer Counts | 32,228 | 32,594 | 32,973 | 33,354 | 33,739 | 34,134 |
| **USL** | Customer Counts | 2,943 | 3,006 | 3,077 | 3,160 | 3,255 | 3,363 |
| **GS>50kw** | Customer Counts | 4,896 | 5,005 | 5,116 | 5,227 | 5,339 | 5,453 |
| **Large Use** | Customer Counts | 2 | 2 | 2 | 2 | 2 | 2 |
| **Street Lighting** | Customer Counts | 43 | 43 | 43 | 43 | 43 | 43 |
| **Sentinel** | Customer Counts | 107 | 106 | 106 | 106 | 106 | 106 |
| **Total Customer Counts in Table 5** | **Customer counts** | **362,543** | **368,663** | **374,990** | **381,372** | **387,845** | **394,508** |
| | | | | | | | |
| **Total Billing Determinate in Table 7** | **Customer counts** | **362,393** | **368,514** | **374,841** | **381,223** | **387,696** | **394,358** |
| | | | | | | | |
| **Difference in Customer Counts** | **Customer counts** | **150** | **149** | **149** | **149** | **149** | **149** |
| | | | | | | | |
| **Street Lighting** | Connections | 87,377 | 88,953 | 90,575 | 92,207 | 93,857 | 95,547 |
| **Sentinel** | Connections | 209 | 207 | 207 | 207 | 207 | 207 |
| **Total Billing Determinants in Table 7** | **Connections** | **87,586** | **89,160** | **90,782** | **92,414** | **94,064** | **95,754** |

b) Please see II-EnergyProbe-16b-Appendix B for the table requested.

**II-Energy Probe-17**

**Ref: Exhibit I, Tab 1**

Please provide the most recent year-to-date actual available for other operating revenues shown in the same level of detail as found in Table 1 for 2015. Please also show the corresponding figures for the same period in 2014.

**RESPONSE:**

Please refer to the response to I-SEC-23 which shows table 2-H (Other Revenue) comparing 2014 to 2015 YTD actuals.

**II-Energy Probe-18**

**Ref: Exhibit I, Tab 1**

What is the current status of the water billing contracts that are up for renewal by the end of 2015?

**RESPONSE:**

PowerStream intends to commence discussions in the near future.

**II-Energy Probe-19**

**Ref: Exhibit J, Tab 1**

a) Please update Table 1 to reflect the most recent year-to-date actuals available for 2015, along with the current forecast for the remainder of the year.

b) Please update Appendix 2-K based on year-to-date actuals for 2015 along with the forecast for the remainder of the year.

c) Please provide the number of FTEs for management and non-management as of the most recent actuals available for 2015.

**RESPONSE:**

a) Please refer to the response to I-SEC-23 which shows table 2-JB (Cost Drivers) comparing 2014 to 2015 YTD actuals. The forecast for 2015 is that PowerStream will meet the figures in the 2015 bridge year in Exhibit J, Tab 1, Table 1.

b) Please see updated Appendix 2-K below.

## Appendix 2-K
## Employee Costs

| | 2012 Actual | 2013 Board Approved | 2013 Actual | 2014 Actual | Jan-Jun 2015 Actual | | Jul-Dec 2015 Forecast | 2015 Forecast | 2016 Forecast | 2017 Forecast | 2018 Forecast | 2019 Forecast | 2020 Forecast |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Number of Employees (FTEs including Part-Time)[1]** | | | | | As of Jun 30 | Total Jan 1 - Jun 30 | | | | | | | |
| Management (including executive) | 103.56 | 110.20 | 104.41 | 105.36 | 102.80 | 53.67 | 58.83 | 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 | 434.60 | 223.65 | 231.30 | 454.95 | 449.37 | 444.87 | 445.12 | 446.12 | 444.12 |
| Total | **518.94** | **550.65** | **533.10** | **544.09** | **537.40** | **277.32** | **290.13** | **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 | $ | 9,565,997 | $ 7,944,003 | $ 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 | $ | 19,459,267 | $ 17,917,113 | $ 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** | **$** | **29,025,264** | **$ 25,861,117** | **$ 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 | $ | 2,610,776 | $ 1,874,595 | $ 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 | $ | 5,493,785 | $ 5,465,112 | $ 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** | **$** | **8,104,561** | **$ 7,339,707** | **$ 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 | $ | 12,176,772 | $ 9,818,598 | $ 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 | $ | 24,953,052 | $ 23,382,225 | $ 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** | **$** | **37,129,825** | **$ 33,200,823** | **$ 70,330,648** | **$ 72,856,589** | **$ 75,044,216** | **$ 77,030,255** | **$ 79,013,616** | **$ 80,681,176** |

c) The table below shows the FTEs.

| | As of June 30, 2015 FTE |
|---|---|
| Management (including executive) | 102.8 |
| Non-Management (union and non-union) | 434.6 |
| Total | 537.4 |

**II-Energy Probe-20**

**Ref: Exhibit J-1-1**

Please provide the most recent year-to-date figures for 2015 available in the same level of detail as shown in Appendix 2-JA, along with the corresponding figures for the same period in 2014.

**RESPONSE:**

Please see the updated table.

| | 2012 Actuals | Last Board-Approved Rebasing Year 2013 | Last Rebasing Year 2013 Actuals | 2014 Actuals | 2014 Jan-Jun Actuals | 2015 Jan-Jun Actuals | 2015 Bridge Year |
|---|---|---|---|---|---|---|---|
| *Reporting Basis* | $'000 | $'000 | $'000 | $'000 | $'000 | $'000 | $'000 |
| Operations | $ 12,468 | $ 12,773 | $ 12,240 | $ 13,211 | $ 6,027 | $ 6,096 | $ 6,096 |
| Maintenance | $ 19,409 | $ 19,091 | $ 20,030 | $ 9,676 | $ 9,676 | $ 9,903 | $ 9,903 |
| **SubTotal** | **$ 31,877** | **$ 31,864** | **$ 32,270** | **$ 22,888** | **$ 15,703** | **$ 15,999** | **$ 16,000** |
| %Change (year over year) | | | 1.2% | -29.1% | | 1.9% | -30.1% |
| %Change (Test Year vs Last Rebasing Year - Actual) | | | | | | | |
| Billing and Collecting | $ 13,315 | $ 14,124 | $ 13,642 | $ 16,089 | $ 7,902 | $ 7,148 | $ 7,148 |
| Community Relations | $ 1,500 | $ 1,399 | $ 1,431 | $ 1,740 | $ 736 | $ 818 | $ 671 |
| Administrative and General | $ 36,101 | $ 35,554 | $ 33,506 | $ 16,602 | $ 16,614 | $ 18,723 | $ 18,723 |
| **SubTotal** | **$ 50,915** | **$ 51,077** | **$ 48,579** | **$ 34,432** | **$ 25,252** | **$ 26,689** | **$ 26,542** |
| %Change (year over year) | | | -4.6% | -29.1% | | 5.7% | -22.9% |
| %Change (Test Year vs Last Rebasing Year - Actual) | | | | | | | |
| **Total** | **$ 82,792** | **$ 82,941** | **$ 80,849** | **$ 57,319** | **$ 40,955** | **$ 42,688** | **$ 42,542** |
| %Change (year over year) | | | -2.3% | -29.1% | | 4.2% | -25.8% |

| | 2012 Actuals | Last Board-Approved Rebasing Year 2013 | Last Rebasing Year 2013 Actuals | 2014 Actuals | 2014 Jan-Jun Actuals | 2015 Jan-Jun Actuals | 2015 Bridge Year |
|---|---|---|---|---|---|---|---|
| Operations | $ 12,468 | $ 12,773 | $ 12,240 | $ 13,211 | $ 6,027 | $ 6,096 | $ 6,096 |
| Maintenance | $ 19,409 | $ 19,091 | $ 20,030 | $ 9,676 | $ 9,676 | $ 9,903 | $ 9,903 |
| Billing and Collecting | $ 13,315 | $ 14,124 | $ 13,642 | $ 16,089 | $ 7,902 | $ 7,148 | $ 7,148 |
| Community Relations | $ 1,500 | $ 1,399 | $ 1,431 | $ 1,740 | $ 736 | $ 818 | $ 671 |
| Administrative and General | $ 36,101 | $ 35,554 | $ 33,506 | $ 16,602 | $ 16,614 | $ 18,723 | $ 18,723 |
| **Total** | **$ 82,792** | **$ 82,941** | **$ 80,849** | **$ 57,319** | **$ 40,955** | **$ 42,688** | **$ 42,542** |
| %Change (year over year) | | | -2.3% | -29.1% | | 4.2% | -25.8% |

**II-Energy Probe-21**

**Ref: Exhibit K, Tab 1**

a) PowerStream has forecast the addition of $45 million in long term debt effective January 1, 2016 at a rate of 4.50%. Please provide an update on any talks with potential lenders and the rate currently available from them.

b) Interest rates have been steady or declining for several years. Please explain why PowerStream has forecast a rate 4.50% for the 2016 issuance when in November, 2014 it was able to borrow $150 million at a rate of 3.239%.

c) How was the rate of 3.239% on the unsecured debentures issued in November, 2014 determined with respect to the Canada bond rates and/or a spread over those rates?

**RESPONSE:**

a) PowerStream does not have an update on talks with potential lenders. PowerStream is provided with indicative pricing by BMO; the most recently provided indicative pricing as of August 2015 shows the all-in rates as follows:

30 year term: 3.80% - 3.85%

10 year term: 2.76% - 2.81%

b) The forecasted rate of 4.5% for the 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 at the time the budget was prepared; in August/September 2014, the all-in interest rate for 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.

c) There are two components of the 3.239% all-in rate, determined on pricing date November 18, 2014 for the Series B Unsecured Debentures:

i. The benchmark yield of 2.004% (based on the Government of Canada 2.50% June 1, 2024 bonds)
ii. Plus the issue spread of 123.5 bps

**II-Energy Probe-22**

**Ref: Exhibit L, Tab 1**

Please update the cost allocation to reflect the street lighting changes as required in the June 12, 2015 letter from the Board regarding the Issuance of New Cost Allocation Policy for Street Lighting Rate Class.

**RESPONSE:**

Please see the response to II-1-Staff-27.

**II-Energy Probe-23**

**Ref: Exhibit M, Tab 1**

Please update the proposed fixed variable splits for residential customers such that the proposal is in compliance with the July 16, 2015 letter from the Board re Implementing a New Rate Design for Electricity Distributors.

**RESPONSE:**

Please see the response to II-1-Staff-28.

**II-SEC-5**

**Ref: II/G2, Appendix A**

For all material 2015 and 2016 capital projects (as opposed to programs), please provide the in-service date by month.

**RESPONSE:**

The in-service dates for the 2015 and 2016 Material Investments capital projects (not programs), by OEB category, are provided below in Table SEC 5.1, Table SEC 5.2 Table SEC 5.3 and Table SEC 5.4.

**Table SEC 5.1**

| Material Investments | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | In-Service Date |
|---|---|---|---|---|---|---|---|
| System Access | ($) | ($) | ($) | ($) | ($) | ($) | |
| New Connections and Subdivisions | | | | | | | |
| New Commercial Subdivision Development | 1,600,010 | 1,601,908 | 1,603,808 | 1,605,707 | 1,607,607 | 1,609,506 | Program |
| New Residential Subdivision Development | 7,895,964 | 8,633,109 | 9,392,346 | 9,759,944 | 10,135,066 | 10,517,394 | Program |
| New Subdivision Development - Secondary Service Lateral | 1,989,034 | 2,173,796 | 2,364,815 | 2,458,773 | 2,554,113 | 2,650,954 | Program |
| O/H and U/G Residential Service Upgrades | 928,921 | 984,657 | 1,043,737 | 1,106,360 | 1,172,741 | 1,243,109 | Program |
| Road Authority | | | | | | | |
| Road Authority Expenditures | 6,258,891 | 9,701,973 | 8,678,858 | 8,356,668 | 5,718,617 | 6,221,949 | Program |
| Metering | | | | | | | |
| GS>50 MIST Meter Program Implementation | 1,592,952 | 1,196,859 | 1,303,795 | 1,308,610 | 1,195,725 | 574,761 | Program |
| Residential Meter "ICON F" Meter Replacement Program | 411,051 | 494,361 | 494,746 | 872,435 | 2,280,384 | 4,517,454 | Program |
| Other Customer Initiated Work | | | | | | | |
| Unforeseen Projects Initiated by the Customer | 329,005 | 786,802 | 929,401 | 1,080,390 | 1,255,781 | 1,414,541 | Program |
| | | | | | | | |

### Table SEC 5.2

| Material Investments | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | |
|---|---|---|---|---|---|---|---|
| **System Renewal** | **($)** | **($)** | **($)** | **($)** | **($)** | **($)** | **In-Service Date** |
| **UG Lines - Planned Asset Replacement** | | | | | | | |
| Cable Injection Program | 4,024,219 | 4,138,312 | 4,255,465 | 4,375,771 | 4,499,323 | 4,626,219 | Program |
| Cable Replacement Program | 11,718,862 | 12,538,684 | 13,607,273 | 14,288,297 | 15,085,861 | 15,340,181 | Program |
| Emerging Cable Replacement Projects | 491,687 | 520,801 | 1,050,756 | 1,081,576 | 1,113,287 | 1,145,915 | Program |
| Submersible Transformer Replacement | 1,040,300 | 620,000 | - | - | - | - | Program |
| Switchgear Replacement Program | 2,003,445 | 2,327,404 | 2,462,129 | 2,533,373 | 2,606,624 | 2,681,945 | Program |
| **Distribution Lines - Emergency/Reactive Replace** | | | | | | | |
| Storm damage - Replacement of Distribution Equip due to Storms | 999,785 | 1,000,232 | 1,005,603 | 1,005,624 | 1,010,352 | 1,010,159 | Program |
| Switchgears - Unscheduled Replacement of Failed Switchgear | 1,420,148 | 1,431,384 | 1,420,148 | 1,421,218 | 1,400,444 | 1,140,858 | Program |
| Unscheduled Replacement of Other Failed Distribution Equip | 4,904,357 | 5,107,035 | 5,206,156 | 5,358,281 | 5,455,354 | 5,305,986 | Program |
| **Overhead Lines - Planned Asset Replacement** | | | | | | | |
| Pole Replacement Program | 4,645,383 | 4,933,143 | 5,570,700 | 5,870,246 | 6,241,483 | 6,244,377 | Program |
| Unforeseen Projects Initiated by PowerStream | 1,046,472 | 1,070,527 | 1,093,812 | 1,117,360 | 1,141,172 | 1,165,266 | Program |
| **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 | Program |
| **Stations/P&C - Planned & Emergency** | | | | | | | |
| Planned Circuit Breaker Replacement Markham TS1&2, Lazenby TS | 747,766 | - | - | 1,087,788 | 1,119,281 | - | Dec-19 |

### Table SEC 5.3

| Material Investments | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | |
|---|---|---|---|---|---|---|---|
| **System Service** | **($ )** | **($ )** | **($ )** | **($ )** | **($ )** | **($)** | **In-Service Date** |
| **Additional Capacity - Stations** | | | | | | | |
| Painswick South MS: New 44-13.8kV, 20 MVA, 4-Feeder Sub | 2,690,054 | - | - | - | - | - | Dec-15 |
| New MS, Dufferin South MS#2 - Alliston | - | 749,000 | 2,299,074 | 4,899,189 | - | - | Dec-18 |
| New MS, Harvie Rd. MS - Barrie | - | 749,000 | - | - | - | 1,700,333 | Dec-21 |
| New MS, Little Lake MS#2 - Barrie | 1,125,311 | 1,603,656 | 3,095,457 | - | - | - | Dec-17 |
| New MS, Melbourne MS#2 - Bradford | - | 749,000 | 1,651,393 | 3,187,430 | - | - | Dec-18 |
| New MS, Mill Street MS#2 - Tottenham | - | 642,000 | 1,821,953 | 3,529,079 | - | - | Dec-18 |
| Vaughan TS #4 - Build Station | 10,249,162 | 11,226,183 | 422,915 | - | - | - | Apr-17 |
| **Additional Capacity -Lines** | | | | | | | |
| 2x44kV circuits (23M22 & 23M23) from Midhurst TS2 to Ess | 5,011,705 | 3,606,692 | 4,460,060 | - | - | - | Dec-17 |
| Install 2x13.8kV ccts Pole Line on Leslie St from Wellingtor | - | 1,131,418 | - | - | - | - | Dec-16 |
| Install Two 27.6kV Ccts on 16th Ave from Hwy 404 to Wood | - | 1,108,593 | - | - | - | - | Dec-16 |
| New 44 kV Feeder (13M7) Barrie TS X Huronia & Big Bay Pt. | 76,925 | 4,726,805 | - | - | - | - | Dec-16 |
| Rebuild 27.6 kV pole line into 4 Ccts on Warden Ave from H | - | 2,039,163 | - | - | - | - | Dec-16 |
| Two Ccts on Birchmount Rd from ROW to Enterprise | 1,201,150 | - | - | - | - | - | Dec-15 |
| 27.6 kV Pole Line on 14th Ave from Hwy 48 to 9th Line | - | 2,039,163 | - | - | - | - | Dec-16 |
| 27.6 kV Pole Line on Reesor Rd from Hwy 7 to 14th Ave | - | 1,496,942 | - | - | - | - | Dec-16 |
| Highway Crossing Remediation - Hwy 407/ East of Dufferin | 1,100,409 | - | - | - | - | - | Dec-15 |
| **Reliability including Dist. Auto.** | | | | | | | |
| Distribution Automation Switches / Reclosers | 1,850,276 | 1,530,249 | 2,080,457 | 2,283,805 | 2,354,895 | 2,409,740 | Program |

**Table SEC 5.4**

| Material Investments | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | |
|---|---|---|---|---|---|---|---|
| **General Plant** | ($ ) | ($ ) | ($ ) | ($ ) | ($ ) | ($) | In-Service Date |
| **Customer Information System (CIS)** | | | | | | | |
| CIS Modifications | 1,403,400 | 3,884,100 | 6,708,900 | 2,996,000 | 2,996,000 | 2,996,000 | Program |
| CIS Replacement Project | 10,300,000 | - | - | - | - | - | Jul-15 |
| **IT & Info/Communication Systems** | | | | | | | |
| MSBPI | - | 10,000 | 60,000 | 899,999 | 50,000 | 10,000 | Program |
| Storage Expansion (Data) | 321,000 | 300,000 | 300,000 | 300,000 | 1,000,000 | 400,000 | Program |
| Work Force Management / Mobile Dispatch | 1,605,000 | 2,675,000 | 802,500 | 802,500 | 535,000 | 535,000 | Program |
| **Buildings & Emerging Operations** | | | | | | | |
| Barrie Building Renovation Project 2015 | 3,149,489 | - | - | - | - | - | Dec-15 |
| **Interest Capitalization** | | | | | | | |
| Interest Capitalization | 1,000,000 | 1,020,000 | 1,040,000 | 1,061,000 | 1,082,000 | 1,104,000 | |
| | | | | | | | |

**II-SEC-6**

**Ref: II/G2**

SEC is interested in understanding how PowerStream, after determining which capital program it believes it needs to do, forecasts the cost of those individuals' projects. Please provide a step-by-step explanation of how PowerStream builds its forecast for capital project and program costs.

**RESPONSE:**

There are two typical approaches to developing the estimates for a capital project or program.

For a capital project such as the construction of an overhead pole line, an initial project scope is developed by planning, and a field review is performed with Lines, Design and System Planning. The scope is reviewed in the field and any issues related to physical constraints are noted by Lines. Design will then use this information from the field visit to develop an estimate for the project. The estimate is formulated based on labour units, material standards, equipment and vehicle times plus all applicable burdens. If contractor costs are required, these are also included.

For a capital program such as pole replacement, cable injection, etc., the quantities proposed form the scope, and the program costs are estimated using unit prices. The unit prices are based on historical actuals for the programs being estimated. If contractor costs are required, these are also included.

**II-SEC-7**

**Ref: II/G/1/2/p.2**

Please provide a revised version of Table 2 and Table 3, showing in-service additions instead of capital expenditures.

**RESPONSE:**

The response to interrogatory II-AMPCO-14, in Section B, Tab1, Schedule 2, provides the reconciliation between capital expenditures and the in-service additions which is the change in work-in-process (“WIP”).

PowerStream is unable to provide the in-service additions by the same grouping as Tables 2 and 3 as requested. PowerStream did not use these grouping when it determined the WIP for purposes of determining in-service additions and completion of the Fixed Asset Continuity Schedules.

**II-SEC-8**

**Ref: II/G2/2/5.3.3/ p.19-25**

For the purposes of the capital project optimization process (C55 program), please explain in sufficient detail how PowerStream measures both the qualitative and quantitative risks and benefits for a project Please explain how weighting of the value function. Please provide all assumptions that are used. Please provide illustrative examples in your response.

**RESPONSE:**

The Value Function, as described in Appendix Staff 51 – PowerStream Value Function v4b (named the VFID), is used to measure the qualitative and quantitative risks and benefits for a project. The value function document describes the parameters assessed for each risk and benefit and how that is used to compute the overall value of the project. The Investment Value Report summarizes how every project was valued for each value measure.

As an example project 102264: C55 Phase 2 (CBMS Replacement). As shown in the Investment Value Report, the overall value of the project is summed from five value measures:

| Value Measure | Value |
|---|---|
| IT Capacity Risk Mitigation | 1054 |
| Hard Financial Benefits | 2711 |
| Soft Financial Benefits<br>Productivity | 195 |
| Investment Cost | -389 |
| Rate Ready Organization | 794 |
| Total Value | 4366 |

The calculation and weighting of each value measure is defined in the VFID, using this investment as an illustrative example:

IT Capacity Risk Mitigation: The assessment of IT Capacity (and all other risks) is performed by the project owner using the consequence and probability table found in Appendix A1 (pages 21 and 22) of the VFID. In this particular case, the existing risk associated with availability of the existing custom built CBMS system was assessed as:

Base Consequence: Minor (Estimated that more than 50 employees would be impacted if the system was unavailable)

Base Probability: Somewhat Likely (Estimated that there was a greater than 3% chance of the event occurring this year)

Using the Risk Matrix found in Appendix A2 (page 23) this results in a base risk score of 65. Because this project eliminates the custom built system the Residual Risk is 0, hence the mitigated risk PER YEAR is 65 value units. The per year value of 65 units is converted to a lifetime value of 1054 units, by taking the present value of the yearly mitigated risk using the discount rate of 5.91%. The value of the discount rate, and the use of present value calculation is described in section 2.3 (page 7) of the VFID.

Hard Financial Benefits: The assessment of hard financial benefits is described in section 3.1 (page 7) of the VFID. The project is estimated to save 1077 hours of internal labor annually and have additional cost savings of $104,800. Using the formula in section 3.1, that provides an annual savings = $61*1077+$104,800 = $170,497. The yearly annual value is converted to a lifetime value of 2711 by using a present value calculation and then converting into value units by dividing by 1000 (as described in the VFID in the first sentence of section 3.1).

Soft Financial Benefits Productivity: The assessment of soft financial benefits is described in section 3.2 (page 8) of the VFID. The project is estimated to save 50 employees, 6 hours per year each. Using the formula in section 3.2, that provides an annual savings of 60*5*(61+103)/2*0.5 = $12,300. The yearly annual value is converted to a lifetime value of 195 by using a present value calculation and then converting into value units by dividing by 1000 (as described in the VFID in the first sentence of section 3.2).

Investment Cost: As described in the VFID in section 6 (page 19) the present value of the cost of the project is converted into value units by dividing by 1000, resulting in a value of -389.

Rate Ready Organization: The assessment of rate ready organization is described in section 4.5 (page 15) of the VFID. The project is deemed to have a positive impact on the ability to prepare and defend rate submissions. As per section 4.5, this result in a yearly benefit of 50 value units. The yearly annual value is converted to a lifetime value of 794 by using a present value calculation.

**II-SEC-9**

**Ref: II/K/3/p2/Appendix 2-K**

With respect to PowerStream's staffing vacancy rates:

a. Please provide PowerStream staffing vacancy rate for each year between 2011-2015.

b. What staffing vacancy rate did PowerStream use for its forecast 2016-2020 compensation costs?

**RESPONSE:**

a) Please see Table I-SEC-9-1 below.

**Table I-SEC-9-1: Vacancies 2011-2015**

| | 2011 Actual | 2012 Actual | 2013 Actual | 2014 Actual | 2015 (Jan-Jun) Actual |
|---|---|---|---|---|---|
| Total FTE Vacancy Rate | 3 | 11 | 17 | 13 | 8 |

b) The staffing vacancy used for the 2016 to 2020 OM&A compensation costs is an average rate of 6.6 FTE's.

**II-SIA-2**

**Ref: Exhibit I, Tab 1, page 1**

With regard to specific service charges, PowerStream notes that it "is not proposing to alter the list or change the charges during the term of the Custom IR." Given the need to fund significant capital expenditures during the rate term, please explain why PowerStream does not believe it to be appropriate to consider updating its specific service charges, both for cost causality reasons and/or as an additional source of revenue?

**RESPONSE:**

Please see the response to interrogatory II-1-Staff-22.

**II-SIA-3**

**Ref: Exhibit I, Tab 1, Page 5 of 5, Table 3**

a) Please recalculate the table of service charges using current cost inputs, and following the calculation methodology included in Schedule 11-2 of the Distribution Rate Handbook, updating for PowerStream's current actual vehicle and labour rates.

b) Please provide a comparison of the annual specific service charge revenue forecast under existing rates, and the potential revenue under the updated rates in a) above.

c) Would PowerStream have any objections or concerns were it to be directed to implement the new rates calculated in a) above during the term of the rate plan?

**RESPONSE:**

a) PowerStream has recalculated the table of service charges using its current actual vehicle and labour rates and following the calculation methodology included in Schedule 11-2 of the Distribution Rate Handbook.

**Table II-SIA-3-1: Recalculated Specific Service Charges (SSC)**

| Current Charge | II-SIA-3 |
|---|---|
| $ 15.00 | $ 20.00 |
| $ 30.00 | $ 45.00 |
| $ 65.00 | $ 90.00 |
| $ 165.00 | $ 240.00 |
| $ 185.00 | $ 270.00 |
| $ 415.00 | $ 585.00 |
| $ 500.00 | $ 560.00 |

Calculation details of each charge type are presented in the set of Tables below.

## Table II-SIA-3-2: Specific Service Charges: Standard Formula and Amounts

| $15 Specific Service Charge Calculation | Rate/Amount | Hours/Units | O/T Factor | Calculated Cost |
|---|---|---|---|---|
| Direct Labour (inside staff) Straight Time | 32.32 | 0.4 | | 12.93 |
| Direct Labour (inside staff) Overtime | | | | |
| Direct Labour (field staff) Straight Time | 39.66 | | | |
| Direct Labour (field staff) Overtime | 39.66 | | | |
| Other Labour (Specify) | | | | |
| Payroll Burden | 30% | | | 3.88 |
| Total Labour Cost | | | | 16.81 |
| Small Vehicle Time | 16.05 | | | |
| Large Vehicle Time | 49.10 | | | |
| Other: Material | | | | |
| Contract | | | | |
| Other | 2 | | | 2 |
| Total Other | | | | 2 |
| Total Cost | | | | 18.81 |
| Specific Service Charge Value Requested - Round to nearest $5.00 | | | | $ 20.00 |

| $30 Specific Service Charge Calculation | Rate/Amount | Hours/Units | O/T Factor | Calculated Cost |
|---|---|---|---|---|
| Direct Labour (inside staff) Straight Time | 32.32 | 0.5 | | 16.16 |
| Direct Labour (inside staff) Overtime | | | | |
| Direct Labour (field staff) Straight Time | 39.66 | 0.3 | | 11.90 |
| Direct Labour (field staff) Overtime | 39.66 | | | |
| Other Labour (Specify) | | | | |
| Payroll Burden | 30% | | | 8.42 |
| Total Labour Cost | | | | 36.48 |
| Small Vehicle Time | 16.05 | 0.3 | | 4.82 |
| Large Vehicle Time | 49.10 | | | |
| Other: Material | | | | |
| Contract | | | | |
| Other | 2 | | | 2.00 |
| Total Other | | | | 6.82 |
| Total Cost | | | | 43.29 |
| Specific Service Charge Value Requested - Round to nearest $5.00 | | | | $ 45.00 |

| $65 Specific Service Charge Calculation | Rate/Amount | Hours/Units | O/T Factor | Calculated Cost |
|---|---|---|---|---|
| Direct Labour (inside staff) Straight Time | 32.32 | 0.5 | | 16.16 |
| Direct Labour (inside staff) Overtime | | | | |
| Direct Labour (field staff) Straight Time | 39.66 | 1 | | 39.66 |
| Direct Labour (field staff) Overtime | 39.66 | | | |
| Other Labour (Specify) | | | | |
| Payroll Burden | 30% | | | 16.75 |
| Total Labour Cost | | | | 72.57 |
| Small Vehicle Time | 16.05 | 1 | | 16.05 |
| Large Vehicle Time | 49.10 | | | |
| Other: Material | | | | |
| Contract | | | | |
| Other | 3 | | | 3.00 |
| Total Other | | | | 19.05 |
| Total Cost | | | | 91.62 |
| Specific Service Charge Value Requested - Round to nearest $5.00 | | | | $ 90.00 |

| $165 Specific Service Charge Calculation | Rate/Amount | Hours/Units | O/T Factor | Calculated Cost |
|---|---|---|---|---|
| Direct Labour (inside staff) Straight Time | 32.32 | 0.6 | | 19.39 |
| Direct Labour (inside staff) Overtime | | | | |
| Direct Labour (field staff) Straight Time | 39.66 | | | |
| Direct Labour (field staff) Overtime | 39.66 | 2 | 2 | 158.64 |
| Other Labour (Specify) | | | | |
| Payroll Burden | 30% | | | 53.41 |
| Total Labour Cost | | | | 231.44 |
| | | | | |
| Small Vehicle Time | 16.05 | 0.3 | | 4.82 |
| Large Vehicle Time | 49.10 | | | |
| Other: Material | | | | |
| Contract | | | | |
| Other | 3 | | | 3.00 |
| Total Other | | | | 7.82 |
| Total Cost | | | | 239.26 |
| Specific Service Charge Value Requested - Round to nearest $5.00 | | | | $ 240.00 |

| $185 Specific Service Charge Calculation | Rate/Amount | Hours/Units | O/T Factor | Calculated Cost |
|---|---|---|---|---|
| Direct Labour (inside staff) Straight Time | 32.32 | 0.5 | | 16.16 |
| Direct Labour (inside staff) Overtime | | | | |
| Direct Labour (field staff) Straight Time | 39.66 | 0.5 | | 19.83 |
| Direct Labour (field staff) Overtime | 39.66 | 2 | 2 | 158.64 |
| Other Labour (Specify) | | | | |
| Payroll Burden | 30% | | | 58.39 |
| Total Labour Cost | | | | 253.02 |
| | | | | |
| Small Vehicle Time | 16.05 | 1 | | 16.05 |
| Large Vehicle Time | 49.10 | | | 0.00 |
| Other: Material | | | | |
| Contract | | | | |
| Other | 2 | | | 2.00 |
| Total Other | | | | 18.05 |
| Total Cost | | | | 271.07 |
| Specific Service Charge Value Requested - Round to nearest $5.00 | | | | $ 270.00 |

| $415 Specific Service Charge Calculation | Rate/Amount | Hours/Units | O/T Factor | Calculated Cost |
|---|---|---|---|---|
| Direct Labour (inside staff) Straight Time | 32.32 | 0.5 | | 16.16 |
| Direct Labour (inside staff) Overtime | | | | |
| Direct Labour (field staff) Straight Time | 39.66 | 1.5 | | 59.49 |
| Direct Labour (field staff) Overtime | 39.66 | 4 | 2 | 317.28 |
| Other Labour (Specify) | | | | |
| Payroll Burden | 30% | | | 117.88 |
| Total Labour Cost | | | | 510.81 |
| | | | | |
| Small Vehicle Time | 16.05 | | | |
| Large Vehicle Time | 49.10 | 1.5 | | 73.65 |
| Other: Material | | | | |
| Contract | | | | |
| Other | 2 | | | 2.00 |
| Total Other | | | | 75.65 |
| Total Cost | | | | 586.46 |
| Specific Service Charge Value Requested - Round to nearest $5.00 | | | | $ 585.00 |

| $500 Specific Service Charge Calculation | Rate/Amount | Hours/Units | O/T Factor | Calculated Cost |
|---|---|---|---|---|
| Direct Labour (inside staff) Straight Time | 32.32 | | | 0.00 |
| Direct Labour (inside staff) Overtime | | | | |
| Direct Labour (field staff) Straight Time | 39.66 | 7.5 | | 297.45 |
| Direct Labour (field staff) Overtime | 39.66 | | | 0.00 |
| Other Labour (Specify) | | | | |
| Payroll Burden | 30% | | | 89.24 |
| Total Labour Cost | | | | 386.69 |
| | | | | |
| Small Vehicle Time | 16.05 | 1.5 | | 24.08 |
| Large Vehicle Time | 49.10 | 3 | | 147.30 |
| Other: Material | | | | |
| Contract | | | | |
| Other | 3 | | | 3.00 |
| Total Other | | | | 174.38 |
| Total Cost | | | | 561.06 |
| Specific Service Charge Value Requested - Round to nearest $5.00 | | | | $ 560.00 |

b) Table below provide a comparison of the annual SSC revenue forecast under existing rates and the potential revenue under the updated rates in Table II-SIA-3-1 above.

**Table II-SIA-3-3: Comparison of the Annual SSC Revenue Forecast**

| | Curent Rates | Updated Rates | Change, $ |
|---|---|---|---|
| 2016 | $3,471,316 | $5,097,408 | $1,626,092 |
| 2017 | $3,474,784 | $5,102,362 | $1,627,578 |
| 2018 | $3,475,039 | $5,102,379 | $1,627,340 |
| 2019 | $3,474,966 | $5,101,970 | $1,627,004 |
| 2020 | $3,476,285 | $5,103,592 | $1,627,307 |

c) PowerStream does not have any objections/concerns if it is directed to implement the new specific service charges rates calculated in a) above during the term of the rate plan. Based on the analysis performed by PowerStream in response to this interrogatory, it appears that the actual cost of providing the services covered by the specific service charges may be significantly greater than the costs recovered at the current rates. PowerStream believes that it would be reasonable to update these rates.

**II-SIA-4**

**Ref: Exhibit J, Tab 2, page 2, Appendix 2K**

a) Please reproduce Appendix 2K by splitting the “Management” category into Executives, Management (Directors and Managers), and Professionals (Supervisors and Professionals) and the "Non-Management" category into Union and Non-Union separately.

b) Using the revised Appendix 2K as per a) above, please show Average Salary and Wages, Average Benefits, and Average Total Compensation per employee by employee type (i.e. Executive, Management, Professionals, Non-union, Union, Total)

**RESPONSE:**

a) Please see the requested revised Appendix 2K on the next page.

# Appendix 2-K
## Employee Costs

| | 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]** | | | | | | | | | | |
| Executive (President, EVP, SVP, VP) | 14.16 | 15.20 | 13.67 | 14.32 | 16.00 | 16.00 | 16.00 | 16.00 | 16.00 | 16.00 |
| Management (Director, Manager) | 49.32 | 54.00 | 49.52 | 51.12 | 54.00 | 56.75 | 57.00 | 57.00 | 57.00 | 57.00 |
| Professional (Supervisor, Engineer) | 48.41 | 50.00 | 50.33 | 48.56 | 52.00 | 54.25 | 54.00 | 54.75 | 55.75 | 55.75 |
| Non-Union | 43.25 | 54.00 | 48.17 | 49.90 | 57.00 | 59.50 | 63.75 | 64.00 | 64.00 | 64.00 |
| 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 including ovetime and incentive pay** | | | | | | | | | | |
| Executive (President, EVP, SVP, VP) | $ 3,985,919 | $ 4,045,577 | $ 3,998,929 | $ 4,155,014 | $ 4,614,681 | $ 4,712,636 | $ 4,807,131 | $ 4,903,274 | $ 4,941,700 | $ 5,058,154 |
| Management (Director, Manager) | $ 6,478,101 | $ 7,204,560 | $ 6,848,171 | $ 7,448,423 | $ 7,939,788 | $ 8,517,364 | $ 8,780,955 | $ 9,001,360 | $ 9,232,835 | $ 9,453,304 |
| Professional (Supervisor, Engineer) | $ 5,505,098 | $ 5,522,687 | $ 5,806,545 | $ 5,828,745 | $ 6,137,239 | $ 6,495,972 | $ 6,613,896 | $ 6,847,061 | $ 7,130,562 | $ 7,305,826 |
| Non-Union | $ 3,983,017 | $ 4,948,187 | $ 4,596,688 | $ 4,859,334 | $ 5,550,838 | $ 5,944,744 | $ 6,508,447 | $ 6,742,104 | $ 6,931,261 | $ 7,094,458 |
| Union | $ 26,830,534 | $ 28,035,553 | $ 27,302,168 | $ 29,013,131 | $ 28,427,326 | $ 29,490,156 | $ 30,764,541 | $ 31,596,641 | $ 32,427,976 | $ 33,038,306 |
| Temp & students | $ 1,906,120 | $ 1,404,595 | $ 2,599,359 | $ 3,174,843 | $ 2,216,509 | $ 1,649,894 | $ 985,162 | $ 987,389 | $ 989,802 | $ 992,267 |
| 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)** | | | | | | | | | | |
| Executive (President, EVP, SVP, VP) | $ 772,181 | $ 379,837 | $ 843,746 | $ 899,748 | $ 528,084 | $ 536,744 | $ 544,910 | $ 556,853 | $ 567,926 | $ 580,890 |
| Management (Director, Manager) | $ 2,168,357 | $ 2,386,245 | $ 2,343,812 | $ 2,545,429 | $ 2,554,564 | $ 2,689,817 | $ 2,754,307 | $ 2,801,702 | $ 2,867,942 | $ 2,940,980 |
| Professional (Supervisor, Engineer) | $ 1,239,801 | $ 1,249,463 | $ 1,396,484 | $ 1,338,332 | $ 1,716,273 | $ 1,819,898 | $ 1,839,070 | $ 1,905,480 | $ 1,978,866 | $ 2,024,039 |
| Non-Union | $ 997,914 | $ 1,349,420 | $ 1,220,222 | $ 1,212,811 | $ 1,881,299 | $ 1,996,017 | $ 2,171,124 | $ 2,227,411 | $ 2,271,703 | $ 2,323,561 |
| 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 | **$ 12,856,133** | **$ 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)** | | | | | | | | | | |
| Executive (President, EVP, SVP, VP) | $ 4,758,100 | $ 4,425,414 | $ 4,842,675 | $ 5,054,761 | $ 5,142,765 | $ 5,249,380 | $ 5,352,041 | $ 5,460,127 | $ 5,509,626 | $ 5,639,045 |
| Management (Director, Manager) | $ 8,646,458 | $ 9,590,805 | $ 9,191,984 | $ 9,993,852 | $ 10,494,351 | $ 11,207,182 | $ 11,535,261 | $ 11,803,062 | $ 12,100,777 | $ 12,394,285 |
| Professional (Supervisor, Engineer) | $ 6,744,899 | $ 6,772,150 | $ 7,203,030 | $ 7,167,077 | $ 7,853,512 | $ 8,315,870 | $ 8,452,965 | $ 8,752,542 | $ 9,109,428 | $ 9,329,866 |
| Non-Union | $ 4,980,931 | $ 6,297,606 | $ 5,816,910 | $ 6,072,145 | $ 7,432,137 | $ 7,940,761 | $ 8,679,571 | $ 8,969,515 | $ 9,202,964 | $ 9,418,019 |
| 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 | $ 3,582,064 | $ 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** | **$ 65,078,345** | **$ 68,754,853** | **$ 70,330,648** | **$ 72,856,589** | **$ 75,044,216** | **$ 77,030,255** | **$ 79,013,616** | **$ 80,681,176** |

b) Please see the requested revised Appendix 2K below.

## Appendix 2-K
## Employee Costs

| | 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]** | | | | | | | | | | |
| Executive (President, EVP, SVP, VP) | 14.16 | 15.20 | 13.67 | 14.32 | 16.00 | 16.00 | 16.00 | 16.00 | 16.00 | 16.00 |
| Management (Director, Manager) | 49.32 | 54.00 | 49.52 | 51.12 | 54.00 | 56.75 | 57.00 | 57.00 | 57.00 | 57.00 |
| Professional (Supervisor, Engineer) | 48.41 | 50.00 | 50.33 | 48.56 | 52.00 | 54.25 | 54.00 | 54.75 | 55.75 | 55.75 |
| Non-Union | 43.25 | 54.00 | 48.17 | 49.90 | 57.00 | 59.50 | 63.75 | 64.00 | 64.00 | 64.00 |
| 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** |
| **Average Salary and Wages including ovetime and incentive pay** | | | | | | | | | | |
| Executive (President, EVP, SVP, VP) | $ 281,462 | $ 266,156 | $ 292,634 | $ 290,248 | $ 288,418 | $ 294,540 | $ 300,446 | $ 306,455 | $ 308,856 | $ 316,135 |
| Management (Director, Manager) | $ 131,337 | $ 133,418 | $ 138,304 | $ 145,707 | $ 147,033 | $ 150,086 | $ 154,052 | $ 157,919 | $ 161,980 | $ 165,847 |
| Professional (Supervisor, Engineer) | $ 113,709 | $ 110,454 | $ 115,363 | $ 120,023 | $ 118,024 | $ 119,741 | $ 122,480 | $ 125,060 | $ 127,902 | $ 131,046 |
| Non-Union | $ 92,095 | $ 91,633 | $ 95,420 | $ 97,386 | $ 97,383 | $ 99,912 | $ 102,093 | $ 105,345 | $ 108,301 | $ 110,851 |
| Union | $ 83,883 | $ 82,312 | $ 85,779 | $ 90,959 | $ 84,204 | $ 87,030 | $ 89,536 | $ 91,958 | $ 94,103 | $ 96,434 |
| Temp & students | $ 43,384 | $ 38,117 | $ 48,930 | $ 51,858 | $ 43,589 | $ 39,737 | $ 35,798 | $ 35,879 | $ 35,967 | $ 36,056 |
| **Average** | **$ 93,823** | **$ 92,910** | **$ 95,952** | **$ 100,130** | **$ 96,725** | **$ 100,218** | **$ 104,046** | **$ 106,735** | **$ 109,147** | **$ 111,824** |
| **Average Benefits (Current + Accrued)** | | | | | | | | | | |
| Executive (President, EVP, SVP, VP) | $ 54,527 | $ 24,989 | $ 61,744 | $ 62,852 | $ 33,005 | $ 33,547 | $ 34,057 | $ 34,803 | $ 35,495 | $ 36,306 |
| Management (Director, Manager) | $ 43,961 | $ 44,190 | $ 47,335 | $ 49,794 | $ 47,307 | $ 47,398 | $ 48,321 | $ 49,153 | $ 50,315 | $ 51,596 |
| Professional (Supervisor, Engineer) | $ 25,608 | $ 24,989 | $ 27,745 | $ 27,558 | $ 33,005 | $ 33,547 | $ 34,057 | $ 34,803 | $ 35,495 | $ 36,306 |
| Non-Union | $ 23,074 | $ 24,989 | $ 25,330 | $ 24,306 | $ 33,005 | $ 33,547 | $ 34,057 | $ 34,803 | $ 35,495 | $ 36,306 |
| Union | $ 23,244 | $ 29,024 | $ 24,485 | $ 24,679 | $ 24,630 | $ 25,374 | $ 25,992 | $ 26,514 | $ 27,032 | $ 27,742 |
| Temp & students | $ 5,533 | $ 6,552 | $ 6,190 | $ 6,652 | $ 8,827 | $ 9,760 | $ 12,496 | $ 12,748 | $ 13,002 | $ 13,262 |
| **Average** | **$ 24,774** | **$ 28,134** | **$ 26,124** | **$ 26,237** | **$ 27,217** | **$ 28,306** | **$ 29,516** | **$ 30,118** | **$ 30,732** | **$ 31,515** |
| **Average Compensation (Salary, Wages, & Benefits)** | | | | | | | | | | |
| Executive (President, EVP, SVP, VP) | $ 335,988 | $ 291,146 | $ 354,378 | $ 353,100 | $ 321,423 | $ 328,086 | $ 334,503 | $ 341,258 | $ 344,352 | $ 352,440 |
| Management (Director, Manager) | $ 175,299 | $ 177,608 | $ 185,640 | $ 195,501 | $ 194,340 | $ 197,483 | $ 202,373 | $ 207,071 | $ 212,294 | $ 217,444 |
| Professional (Supervisor, Engineer) | $ 139,318 | $ 135,443 | $ 143,107 | $ 147,581 | $ 151,029 | $ 153,288 | $ 156,536 | $ 159,864 | $ 163,398 | $ 167,352 |
| Non-Union | $ 115,169 | $ 116,622 | $ 120,750 | $ 121,692 | $ 130,388 | $ 133,458 | $ 136,150 | $ 140,149 | $ 143,796 | $ 147,157 |
| Union | $ 107,127 | $ 111,337 | $ 110,264 | $ 115,638 | $ 108,834 | $ 112,404 | $ 115,528 | $ 118,471 | $ 121,135 | $ 124,176 |
| Temp & students | $ 48,917 | $ 44,668 | $ 55,121 | $ 58,509 | $ 52,416 | $ 49,498 | $ 48,294 | $ 48,627 | $ 48,969 | $ 49,318 |
| **Average** | **$ 118,597** | **$ 121,045** | **$ 122,076** | **$ 126,367** | **$ 123,942** | **$ 128,524** | **$ 133,562** | **$ 136,853** | **$ 139,879** | **$ 143,339** |

**II-SIA-5**

**Ref: Exhibit F, Tab 1, page 3**

PowerStream notes that “Based on the Board’s approach under price cap IR, PowerStream concludes that the Board’s expectation would be for PowerStream to demonstrate annual productivity savings of 0.3% or greater.”

Does this expectation not also assume that overall costs are to be constrained to a range limited by inflation minus productivity? That is, does PowerStream believe that strictly looking at “savings” in isolation is meaningful without considering them in the context of the overall proposed annual OM&A increase?

**RESPONSE:**

PowerStream does believe that looking at savings in this manner is meaningful.

The Price Cap IR is a measure based on the principle that it is not practical for the Board to conduct a full cost of service review for all distributors on an annual basis.

Price Cap IR assumes that there are no significant changes other than inflation and applies a price cap of inflation less a productivity factor. The Board applies Price Cap IR for a limited period of time following a Cost of Service review with the expectation that distributors will be able to manage under these conditions over a short term.

A Cost of Service review, which includes a Custom IR rate plan as filed by PowerStream, is an opportunity for the Board to review changes in a distributor’s requirements and costs. PowerStream has provided substantial evidence why overall costs and rates cannot be constrained to a range limited by inflation minus productivity.

**II-SIA-6**

**Ref: Exhibit G, Tab 3, page 1**

The application is based on a working capital allowance of 13%. Will PowerStream be updating this factor to 7.5% to align with the OEB's most recent direction in its June 3, 2015 letter to distributors?

**RESPONSE:**

Please see the response to interrogatory II-1-Staff-19.

**II-SIA-7**

**Ref: Exhibit M, Tab 1, page 4**

With regard to the fixed-variable split, PowerStream notes that "PowerStream has not incorporated any of the rate designs as outlined in the Draft Report of the Board at this time. However, should the OEB issue direction to LDCs related to this consultation, PowerStream is prepared to incorporate changes as applicable."

Given the release of the OEB's April 2, 2015 Board Policy decision, and the follow-up July 16 2015 letter, will PowerStream be updating its fixed-variable split for its proposed rates, such that it is in compliance with the four year implementation requirements set out by the OEB?

**RESPONSE:**

Please see the response to II-1-Staff-28.

**II-SIA-8**

**Ref: Exhibit G, Tab 2, page 2**

PowerStream's spending under the System Renewal category is forecast to increase by 94% between 2011-2015 and 2016-2020.

a) Did PowerStream consider a more gradual or moderate pace of increase in renewal spending? If so, why was it rejected in favor of the proposed approach. If not, why not?
b) To what extent was this level of increased spending made known to customers during the various customer engagement activities?

**RESPONSE:**

a) PowerStream commenced the creation of its asset management plan for the distribution system in 2010 and started to implement and increase its asset renewal from year 2010. The current level of investments for two of the largest categories (cables and poles) reached a steady state in 2012.

   PowerStream has been developing and expanding its asset condition assessment process and adding assets to the renewal program. Mini-Rupter switch replacements, automated switch replacements and Station switchgear replacements are recent additions. The Storm Hardening work plan has been included in the asset replacement program.

   PowerStream’s asset management plans are methodical and based on the asset condition assessment program. Refer to TCQ-17 (previous IR process) where PowerStream details the condition of the various assets and their pace of replacement. As seen in the table within TCQ-17, PowerStream is pacing its investments as the replacement numbers are below the quantities that both the condition and end of life statistics warrant.

   PowerStream’s ACA models project replacement 20 years out in the future and it is seen if PowerStream were to defer these investments into the future, the investment required will increase and possibly be unmanageable both from cost and resource perspective.

b) Refer to the response to Staff 57c.

**II-SIA-9**

**Ref: Exhibit G, Tab 2, page 5 and 6**

PowerStream states that it has begun using its new Oracle-based Customer Information System ("CIS") in 2015, but also notes that "The investments included for the CIS Replacement project are $19.9 million for 2016-2020". Please break out in detail theses additional CIS costs that are planned over 2016-2020.

**RESPONSE:**

Please see section IV, Tab 1 page 15 of the application which breaks out the details of these costs.

**II-SIA-10**

**Ref: Exhibit G, Tab 2, Section 5.2.3, page 11**

PowerStream notes that following the Ice Storm in 2013 "One of the recommendations was to analyze and provide recommendations for improvements to PowerStream's distribution grid to make the system more resilient to these types of events. An RFP to acquire the services of an external consultant firm was issued and awarded with respect to 'System Hardening'. A report was prepared, and several recommendations were provided."

a) Please provide the above referenced report.

b) Please list the referenced recommendations, and provide a status for each as to whether it was implemented or is in the process of being implemented. For any recommendations that PowerStream has chosen not to adopt, please explain why.

**RESPONSE:**

a) The Hardening the Distribution System against Severe Storms report was submitted during the April settlement process, and can be found in TCQ-2-G-SEC-19, Appendix B within the EB2015-003 May 22, 2015 application.

b) Refer to Appendix SIA-10b. The table lists each of CIMA's recommendations, PowerStream's responses and planned actions. Also included are the correlated monies that have been included in the rate application.

**II-SIA-11**

**Ref: Exhibit G, Tab 2, Section 5.2.3, page 13**

Please provide SAIFI and SAIDI broken down by cause code, both including and excluding major event days.

**RESPONSE:**

Refer to Table SIA-11.1 and Table SIA-11.2 below.

**Table SIA-11.1**

**Total SAIDI 2007-2014 (Excl: MED)**

| Cause | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Cause Code | Description | 2007 (300455) | 2008 (309325) | 2009 (317145) | 2010 (325233) | 2011 (332232) | 2012 (340154) | 2013 (346722) | 2014 (353954) |
| Controllable | 1 | Scheduled Outage | 2.53 | 8.96 | 6.47 | 3.26 | 4.07 | 4.32 | 7.52 | 8.37 |
| | 3 | Tree Contact | 6.83 | 7.22 | 3.37 | 2.64 | 1.82 | 3.05 | 6.63 | 3.24 |
| | 5 | Defective Equipment | 28.46 | 20.06 | 26.45 | 14.28 | 30.63 | 30.48 | 35.73 | 29.13 |
| | 8 | Human Element | 2.02 | 1.49 | 0.50 | 0.72 | 0.22 | 0.66 | 2.38 | 0.58 |
| | Controllable Total | | 39.84 | 37.73 | 36.79 | 20.90 | 36.75 | 38.51 | 52.26 | 41.31 |
| Uncontrollable | 0 | Unknown | 6.64 | 6.61 | 3.61 | 0.69 | 0.72 | 1.61 | 0.66 | 1.82 |
| | 2 | Loss of Supply | 6.68 | 17.81 | 12.70 | 6.19 | 3.38 | 6.85 | 3.87 | 3.39 |
| | 4 | Lightning | 4.62 | 5.16 | 1.70 | 2.10 | 4.26 | 3.14 | 0.55 | 4.87 |
| | 6 | Adverse Weather | 7.59 | 7.08 | 14.81 | 0.52 | 11.26 | 10.22 | 5.75 | 2.43 |
| | 7 | Adverse Environment | 0.13 | 1.24 | 0.41 | 0.83 | 0.28 | 1.19 | 0.25 | 9.66 |
| | 9 | Foreign Inteference | 9.76 | 8.81 | 3.01 | 6.97 | 7.07 | 7.76 | 9.70 | 10.23 |
| | Uncontrollable Total | | 35.42 | 46.72 | 36.23 | 17.29 | 26.97 | 30.77 | 20.79 | 32.40 |
| Total | | | 75.26 | 84.45 | 73.02 | 38.19 | 63.71 | 69.28 | 73.05 | 73.71 |

**Total SAIFI 2007-2014 (Excl: MED)**

| Cause | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Cause Code | Description | 2007 (300455) | 2008 (309325) | 2009 (317145) | 2010 (325233) | 2011 (332232) | 2012 (340154) | 2013 (346722) | 2014 (353954) |
| Controllable | 1 | Scheduled Outage | 0.02 | 0.06 | 0.03 | 0.03 | 0.04 | 0.04 | 0.04 | 0.05 |
| | 3 | Tree Contact | 0.12 | 0.15 | 0.05 | 0.03 | 0.03 | 0.05 | 0.08 | 0.08 |
| | 5 | Defective Equipment | 0.48 | 0.34 | 0.39 | 0.32 | 0.47 | 0.51 | 0.63 | 0.51 |
| | 8 | Human Element | 0.20 | 0.10 | 0.01 | 0.10 | 0.03 | 0.07 | 0.07 | 0.06 |
| | Controllable Total | | 0.83 | 0.64 | 0.48 | 0.47 | 0.57 | 0.67 | 0.82 | 0.69 |
| Uncontrollable | 0 | Unknown | 0.21 | 0.11 | 0.15 | 0.08 | 0.13 | 0.18 | 0.10 | 0.12 |
| | 2 | Loss of Supply | 0.12 | 0.31 | 0.14 | 0.11 | 0.17 | 0.17 | 0.10 | 0.05 |
| | 4 | Lightning | 0.15 | 0.07 | 0.03 | 0.06 | 0.04 | 0.24 | 0.06 | 0.15 |
| | 6 | Adverse Weather | 0.09 | 0.19 | 0.17 | 0.05 | 0.11 | 0.26 | 0.11 | 0.09 |
| | 7 | Adverse Environment | 0.00 | 0.01 | 0.00 | 0.01 | 0.01 | 0.02 | 0.01 | 0.12 |
| | 9 | Foreign Inteference | 0.21 | 0.14 | 0.06 | 0.13 | 0.11 | 0.17 | 0.21 | 0.25 |
| | Uncontrollable Total | | 0.78 | 0.82 | 0.55 | 0.44 | 0.56 | 1.04 | 0.59 | 0.79 |
| Total | | | 1.61 | 1.46 | 1.04 | 0.91 | 1.13 | 1.71 | 1.41 | 1.48 |

## Table SIA-11.2

**Total SAIDI 2007-2014 (Incl: MED)**

| Cause | Cause Code | Description | 2007 (300455) | 2008 (309325) | 2009 (317145) | 2010 (325233) | 2011 (332232) | 2012 (340154) | 2013 (346722) | 2014 (353954) |
|---|---|---|---|---|---|---|---|---|---|---|
| Controllable | 1 | Scheduled Outage | 2.53 | 8.96 | 6.47 | 3.27 | 4.08 | 4.32 | 7.55 | 8.40 |
| | 3 | Tree Contact | 14.50 | 7.22 | 15.02 | 2.64 | 1.82 | 3.05 | 12.81 | 6.09 |
| | 5 | Defective Equipment | 31.08 | 20.06 | 29.16 | 14.38 | 30.64 | 30.48 | 56.28 | 31.81 |
| | 8 | Human Element | 2.16 | 1.49 | 0.50 | 0.72 | 0.22 | 0.66 | 2.38 | 0.58 |
| | Controllable Total | | 50.27 | 37.73 | 51.15 | 21.01 | 36.77 | 38.51 | 79.01 | 46.88 |
| Uncontrollable | 0 | Unknown | 8.91 | 6.61 | 3.61 | 0.69 | 0.72 | 1.61 | 0.76 | 1.82 |
| | 2 | Loss of Supply | 6.68 | 17.81 | 23.36 | 16.60 | 9.31 | 6.85 | 54.50 | 3.52 |
| | 4 | Lightning | 11.36 | 5.16 | 6.30 | 2.10 | 4.28 | 3.14 | 1.00 | 4.87 |
| | 6 | Adverse Weather | 45.84 | 7.08 | 30.29 | 0.52 | 13.50 | 10.22 | 495.34 | 10.02 |
| | 7 | Adverse Environment | 0.13 | 1.24 | 0.41 | 0.83 | 0.28 | 1.19 | 0.25 | 9.66 |
| | 9 | Foreign Inteference | 9.76 | 8.81 | 3.01 | 6.97 | 7.07 | 7.76 | 9.87 | 10.33 |
| | Uncontrollable Total | | 82.68 | 46.71 | 66.97 | 27.70 | 35.17 | 30.77 | 561.72 | 40.23 |
| Total | | | 132.95 | 84.44 | 118.13 | 48.71 | 71.93 | 69.28 | 640.73 | 87.11 |

**Total SAIFI 2007-2014 (Incl: MED)**

| Cause | Cause Code | Description | 2007 (300455) | 2008 (309325) | 2009 (317145) | 2010 (325233) | 2011 (332232) | 2012 (340154) | 2013 (346722) | 2014 (353954) |
|---|---|---|---|---|---|---|---|---|---|---|
| Controllable | 1 | Scheduled Outage | 0.02 | 0.06 | 0.03 | 0.03 | 0.04 | 0.04 | 0.04 | 0.05 |
| | 3 | Tree Contact | 0.15 | 0.15 | 0.09 | 0.03 | 0.03 | 0.05 | 0.18 | 0.11 |
| | 5 | Defective Equipment | 0.49 | 0.34 | 0.41 | 0.32 | 0.47 | 0.51 | 0.66 | 0.56 |
| | 8 | Human Element | 0.22 | 0.10 | 0.01 | 0.10 | 0.03 | 0.07 | 0.07 | 0.06 |
| | Controllable Total | | 0.88 | 0.65 | 0.54 | 0.47 | 0.57 | 0.67 | 0.95 | 0.78 |
| Uncontrollable | 0 | Unknown | 0.22 | 0.11 | 0.15 | 0.08 | 0.13 | 0.18 | 0.16 | 0.12 |
| | 2 | Loss of Supply | 0.12 | 0.31 | 0.16 | 0.12 | 0.23 | 0.17 | 0.30 | 0.07 |
| | 4 | Lightning | 0.25 | 0.07 | 0.07 | 0.06 | 0.04 | 0.24 | 0.07 | 0.15 |
| | 6 | Adverse Weather | 0.23 | 0.19 | 0.24 | 0.05 | 0.15 | 0.26 | 0.84 | 0.22 |
| | 7 | Adverse Environment | 0.00 | 0.01 | 0.00 | 0.01 | 0.01 | 0.02 | 0.01 | 0.12 |
| | 9 | Foreign Inteference | 0.21 | 0.14 | 0.06 | 0.13 | 0.11 | 0.17 | 0.21 | 0.25 |
| | Uncontrollable Total | | 1.03 | 0.83 | 0.69 | 0.45 | 0.66 | 1.04 | 1.59 | 0.93 |
| Total | | | 1.91 | 1.48 | 1.23 | 0.92 | 1.23 | 1.71 | 2.54 | 1.71 |

**II-SIA-12**

**Ref: Exhibit G, Tab 2, Appendix F, page 50**

PowerStream states that "While most customers feel that PowerStream's rate increase is necessary, many want to be reassured that rates do not continue to increase indefinitely at such a significant level."

What reassurance has PowerStream put forward, or what long term rate trends has PowerStream forecast, that address this condition of its customers' acceptance of the proposed rate increases over the 2016-2020 timeframe of this application.

**RESPONSE:**

PowerStream explained the reason for the increase in the first year of the rate plan which is due to the revenue shortfall between the actual revenue requirements for 2014 and 2015 compared to the revenue provided under Price Cap rate increases. PowerStream explained that by filing a Custom IR plan, this source of "pent-up" rate increase would be eliminated in the future.

PowerStream provided information on rate impacts over the 2016 to 2020 timeframe, separated into the drivers of capital and operating costs. This information shows that the rate impacts decline significantly in the later years of the plan. PowerStream did not provide any rate projections beyond 2020.

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**II-VECC-1**

**Ref: E-A/T1, pg. 3-5**

a) Please indicate precisely what elements of the cost of power will be updated annually. For example, will just the rates (e.g. commodity, transmission, etc.) used in the calculation be updated or will any of the following also be updated:
i) the RPP/non-RPP split,
ii) the ratio of IESO or HON transmission demand to system demand or
iii) the ratio of LV usage to peak usage?

**RESPONSE:**

All elements of the cost of power, except the load forecast, are proposed for annual update. These elements including:

- Commodity costs:
    - Energy and Global Adjustment rate for RPP and non-RPP customers per the semi-annual RPP Price Reports and Ontario Wholesale Electricity Market Price Forecast issued by the Board;
    - The RPP/non-RPP kWh split based on the latest historical actual consumption;
- IESO related charges:
    - Uniform Transmission Rates, Wholesale Market Service rate, Rural or Remote Electricity Rate Protection, and Smart Meter Entity Charge;
    - Latest 3-year historical average ratios: Transmission Total System Demand to Total Energy Purchase, Transmission Line Connection Demand to Total System Demand, and Transmission Transformation Connection Demand to Total System Demand.
- Hydro One related charges:
    - Hydro One Distribution's Sub-transmission rates;
    - Latest 3-year historical average ratios: Transmission Total System Demand to Total Energy Purchase, Transmission Line Connection Demand to Total

System Demand, and Transmission Transformation Connection Demand to Total System Demand;

- Hydro One Low Voltage rate and the latest 3-year historical average ratio calculated between the Low Voltage demand and system demand.

**II-VECC-2**

**Ref: Exhibit J/Tab 1/pg.3 / Section I/T1/S1/pg.4**

a) Please provide the updated capital costs of the CIS system.

b) Are all capital costs of this project now completed and in-service?

c) What was the capital and maintenance cost of the CIS system when this project was originally budgeted?

d) Please detail the $1,392,000 in training costs including the period over which this spending is to take place.

e) Is the new billing system shared for the use of water billing or used by any other party?

f) If yes please provide a description of the billing functions that were purchased or developed for the purpose of shared billing.

g) If water billing undertaken by PowerStream is not renewed what is the Utility's proposal for recouping its investments for shared billing.

**RESPONSE:**

a) The updated capital cost of the CIS system is $42.8M.

b) All capital costs are not yet in-service. The $42.8M noted above includes $39.7M that was capitalized in July 2015, and an estimated $3.1M of remaining project costs relating to costs incurred but not yet billed by vendors which will also be capitalized in 2015; when paid, these costs will be added to the in-service capital cost of the project for an overall total project capital cost of $42.8M.

c) When the project was originally budgeted in 2011, the capital budget was $34.5M and the OM&A budget was $1.2M (see Section III, Tab 2, B-CCC-15, Appendix A, pg.3).

d) The $1,392K in CIS training relates to training the customer service staff within the Customer Service Department on the new CC&B system. The training includes consultant costs to prepare and set up training tools, develop training material, train the trainer sessions, and delivery of comprehensive training. The training took place primarily in 2014 ($1,350K) and the remaining expenditures will take place over the 2015-2017 period (see Section III, Tab 1, Schedule 1, pg 36 B-CCC-15 Table B-CCC-15-2).

e) The new customer care and billing system also provides water billing for legacy agreements with the City of Markham and the City of Vaughan.

f) The need for the new customer care and billing system was driven by the requirement for updated electricity billing functionality. There was no additional functionality purchased for water billing and water billing leverages off the core electricity billing functionality. As such, there are no incremental costs related solely to water billing.

g) If water billing is not renewed, PowerStream does not intend to seek recovery of the lost revenue.

**II-VECC-3**

**Ref: Exhibit J/T2/pg.2**

a) What are the current FTEs of PowerStream?

**RESPONSE:**

a) Table II-VECC-3 below shows the current FTEs.

| | As of June 30, 2015<br><br>FTE |
|---|---|
| Management (including executive) | 102.8 |
| Non-Management (union and non-union) | 434.6 |
| Total | 537.4 |

**II–VECC-4**

**Ref: E-H/Appendix H-1-3, pg. 13-14, E-H/T1, pg. 7**

a) Please reconcile the forecast negative growth for PowerStream's Large Use class with the Conference Board forecast for "moderate economic growth for the Toronto CMA over the next five years".

**RESPONSE:**

a) During the course of developing Large Use class load forecast, PowerStream discussed with the two large use customers individually regarding to their respective future energy demand outlook. Both had indicated that, the future energy demand will be decreased by approximately 1% annually over the rate period, due to decreasing sales demand and/or operational efficiency which is expected in the next 5 years.

Based on our discussion with the two Large Use customers, PowerStream believes that the Large Use load forecast, derived from historical average consumption, is reasonably accurate and has confirmed by the discussion with customers.

**II–VECC-5**

**Ref: E-H/T1, pg.6-7**

a) Please provide a schedule that for the years 2102, 2013 and 2014 and for each of the Residential, GS<50 and GS>50 classes compares: i) actual class sales (kWh); ii) predicted class sales (kWh) based on the actual values for the independent variables used in the model for each class and iii) the predicted class sales (kWh) based on the actual values for all independent variables except HDD and CDD, where the weather normal values should be used.

b) Please provide a schedule that sets out the forecast energy sales by customer class (2015-2020) prior to any manual CDM adjustments that reconciles with the total values in Table 1.

c) Please provide a schedule that sets out the forecast energy sales by customer class (2015-2020) after the manual CDM adjustments that reconciles with the total values in Table 1.

d) Please provide the total sales forecasts for 2015-2020 (prior to any CDM adjustment) using a 20-year trend for HDD and CDD as the definition for weather normal, per the Board's July 2014 Chapter 2 Filing Guidelines (pg. 28).

**RESPONSE:**

a) Please see the schedule below which provides the requested schedule for 2012-2014 in kWh.

| | Residential | | | GS<50 | | | GS>50 | | |
|---|---|---|---|---|---|---|---|---|---|
| Year | Actual | Predicted Actual | Weather Normal Actual | Actual | Predicted Actual | Weather Normal Actual | Actual | Predicted Actual | Weather Normal Actual |
| 2012 | 2,765,593,702 | 2,808,772,106 | 2,765,141,840 | 1,019,490,761 | 1,027,797,450 | 1,030,076,810 | 4,527,700,596 | 4,542,274,876 | 4,525,858,110 |
| 2013 | 2,691,200,335 | 2,739,212,609 | 2,788,567,100 | 1,023,964,950 | 1,027,456,894 | 1,032,827,510 | 4,567,298,357 | 4,517,004,280 | 4,529,954,170 |
| 2014 | 2,678,319,642 | 2,644,727,555 | 2,755,882,380 | 1,035,615,591 | 1,038,655,870 | 1,038,922,170 | 4,516,967,995 | 4,530,232,638 | 4,551,229,470 |

b) Please see the schedule below which sets out the forecast energy sales (kWh) by customer class (2015-2020) prior to any manual CDM adjustments.

| | 2015 Bridge | 2016 Test Year | 2017 Test Year | 2018 Test Year | 2019 Test Year | 2020 Test Year |
|---|---|---|---|---|---|---|
| Residential | 2,751,917,992 | 2,762,436,973 | 2,771,454,995 | 2,795,225,056 | 2,825,613,348 | 2,851,778,510 |
| GS<50kw | 1,046,020,760 | 1,055,538,560 | 1,061,218,790 | 1,068,522,570 | 1,076,785,010 | 1,087,583,630 |
| USL | 13,806,616 | 14,169,725 | 14,542,385 | 14,924,845 | 15,317,364 | 15,720,206 |
| GS>50kw | 4,569,914,578 | 4,631,624,127 | 4,673,754,125 | 4,717,848,974 | 4,759,854,442 | 4,808,773,270 |
| Large Use | 77,114,535 | 76,536,992 | 75,964,677 | 75,397,535 | 74,835,513 | 74,278,555 |
| Street Lighting | 60,109,272 | 53,007,707 | 45,961,281 | 38,502,066 | 38,115,123 | 37,566,265 |
| Sentinel | 378,810 | 378,100 | 377,900 | 377,850 | 377,830 | 377,830 |
| **Total** | **8,519,262,563** | **8,593,692,185** | **8,643,274,153** | **8,710,798,896** | **8,790,898,630** | **8,876,078,266** |

c) Please see the schedule below which sets out the forecast energy sales (kWh) by customer class (2015-2020) after the manual CDM adjustments.

| | 2015 Bridge | 2016 Test Year | 2017 Test Year | 2018 Test Year | 2019 Test Year | 2020 Test Year |
|---|---|---|---|---|---|---|
| Residential | 2,749,691,613 | 2,750,618,680 | 2,739,228,627 | 2,734,798,535 | 2,726,183,581 | 2,713,502,642 |
| GS<50kw | 1,041,113,015 | 1,040,222,617 | 1,034,670,636 | 1,029,394,734 | 1,023,938,194 | 1,020,971,574 |
| USL | 13,806,616 | 14,169,725 | 14,542,385 | 14,924,845 | 15,317,364 | 15,720,206 |
| GS>50kw | 4,551,009,658 | 4,574,077,601 | 4,574,818,691 | 4,569,273,134 | 4,555,886,909 | 4,549,129,870 |
| Large Use | 77,114,535 | 76,536,992 | 75,964,677 | 75,397,535 | 74,835,513 | 74,278,555 |
| Street Lighting | 60,109,272 | 53,007,707 | 45,961,281 | 38,502,066 | 38,115,123 | 37,566,265 |
| Sentinel | 378,810 | 378,100 | 377,900 | 377,850 | 377,830 | 377,830 |
| **Total** | **8,493,223,520** | **8,509,011,422** | **8,485,564,197** | **8,462,668,700** | **8,434,654,514** | **8,411,546,941** |

d) Please see the schedule below which sets out the forecast energy sales in GWh by customer class (prior to any CDM adjustment) using a 20-year trend for HDD and CDD as the definition for weather normal.

| GWh | Assuming 10 - Years Average HDD10/CDD18 | Assuming 20 - Years Average HDD10/CDD18 | 10 Years vs. 20 Years Variance |
|---|---|---|---|
| **2015 Bridge Year** | 8,519.26 | 8,490.74 | 28.52 |
| **2016 Test Year** | 8,593.69 | 8,565.10 | 28.59 |
| **2017 Test Year** | 8,643.27 | 8,614.61 | 28.66 |
| **2018 Test Year** | 8,710.80 | 8,682.06 | 28.74 |
| **2019 Test Year** | 8,790.90 | 8,762.07 | 28.83 |
| **2020 Test Year** | 8,876.08 | 8,847.17 | 28.91 |

**II–VECC-6**

**Ref: E-I, Tab 1, page 4**

a) Please provide a schedule using the same format as Table 2 that sets out the Other Operating Revenues for the first six months of 2014 and 2015.

**RESPONSE:**

a) Please refer to the response to I-SEC-23 which shows table 2-H (Other Revenue) comparing 2014 to 2015 YTD actuals.

**II–VECC-7**

**Ref: Cost Allocation Models (2016-2020)**

a) With respect to Tab I6.2, please explain why there are no “Secondary Customer Base” customers shown for the GS<50, Street Lighting or USL classes. Don’t any of the customers in these classes take service off of PowerStream’s secondary system?

b) Do any GS>50 customers take service off of PowerStream’s secondary system?

**RESPONSE:**

a) Upon further checking with PowerStream technical staff, it was discovered that there are some circumstances where GS<50, Street Lighting and USL customers take service from PowerStream’s secondary system. The revised Secondary Customer Base is provided in Table II-VECC-7 below.

**Table II- VECC-7: Revised I6.2 Secondary Customer Base**

| Billing Data | Residential | GS<50 | GS>50 | Large User | Streetlight | Sentinel | Unmetered Scattered Load |
|---|---|---|---|---|---|---|---|
| Secondary Customer Base - Submitted | 331,676 | 0 | 0 | 0 | 0 | 101 | 0 |
| Secondary Customer Base - Revised | 331,676 | 14,760 | 0 | 0 | 24 | 101 | 1,370 |

b) All GS>50 customers supply and own their own secondary conductor. There is no PowerStream owned secondary that supplies GS>50 customers.

**II–VECC-8**

**Ref: Cost Allocation Models (2016-2020) EB-2012-0383 – Cost Allocation Policy for Unmetered Loads**

a) On June 12, 2015 the Board issued a new cost allocation policy with respect to Street Lighting. When a new Cost Allocation model, consistent with this policy is posted by the Board, please re-run the 2016-2020 models and file updated versions of Appendix 2-P for 2016-2020.

**RESPONSE:**

a) Please refer to II-1-Staff-27.

**II-VECC-9**

**Ref: E-G/T2/ Work Order Variance Reporting**

a) What is the variance within which completed orders are not required to be reported?

b) Please provide the gross Work Order Closing Variances for each of the category of projects (System Access/Renewal/Service and General Plant) for the years 2012 through 2014.

c) Please provide the target for this metric for each year of the plan.

**RESPONSE:**

a) All completed and closed work orders are reviewed and analyzed for variances, no matter how large or small, and recorded and reported in a tracking spreadsheet for monthly reporting. This monthly reporting is shown in Figure 2 of page 5 of 19, Section 5.2.3 of the DS Plan.

b) Refer to Tables VECC 9b.1 and Table VECC 9b.2 below for gross variances for 2013 and 2014. As mentioned in IR response to G-SEC-16d found in Section III, Tab 1, Schedule 1, page 192 of 363, "The Work Order Review and Closing Process, in its current form, did not exist in 2012."

**Table VECC 9b.1 – Paper Trail Variances**

| Paper Trail WO OEB Category | Year | Variance Total |
|---|---|---|
| System Access | 2013 Total | - 256,036 |
| | 2014 Total | -3,051,022 |
| | | |
| System Renewal | 2013 Total | -1,553,678 |
| | 2014 Total | -4,204,903 |
| | | |
| System Service | 2013 Total | - 168,433 |
| | 2014 Total | - 192,968 |
| | | |

**Table VECC 9b.2 – Non-Paper Trail Variances**

| Non-Paper Trail WO OEB Category | Year | Variance Total |
|---|---|---|
| System Access | 2013 Total | N/A |
| | 2014 Total | - 23,125 |
| | | |
| System Renewal | 2013 Total | N/A |
| | 2014 Total | 84,253 |
| | | |
| System Service | 2013 Total | N/A |
| | 2014 Total | 1,087,841 |
| | | |
| General Plant | 2013 Total | N/A |
| | 2014 Total | - 467,487 |
| | | |

*Caution* These tables cannot be tied back to original budget estimates in a meaningful manner as the variance analysis is based at a specific work order level which does not tie back to the budget level.

c) As mentioned in the interrogatory response to G-AMPCO-6h found on Section III, Tab 1, Schedule 1, page 127 of 363, the target for this metric is 50% or higher. Please also refer to the interrogatory response to G-SEC-16a found in Section III, Tab 1, Schedule 1, page 191 of 363.

**II-VECC-10**

**Ref: E-G/T2**

a) Please show the proportion of administrative and capital planning and engineering costs to total capital costs for each of the capital plan categories (i.e. System Access/Renewal/ Service & General Plant) and for the years 2012 through 2014.

**RESPONSE:**

a) Refer to Table VECC-10a.1 and Table VECC 10a.2 below.

**Table VECC-10a.1**

**Costs**

| Admin/Cap Plan | 2012 Actual $ '000 | 2013 Actual $ '000 | 2014 Actual $ '000 | 2015 Plan $ '000 | 2016 Plan $ '000 | 2017 Plan $ '000 | 2018 Plan $ '000 | 2019 Plan $ '000 | 2020 Plan $ '000 |
|---|---|---|---|---|---|---|---|---|---|
| System Access | 3,653 | 2,506 | 2,840 | 2,778 | 3,287 | 3,362 | 3,493 | 3,436 | 3,741 |
| System Renewal | 984 | 1,766 | 2,188 | 2,773 | 3,187 | 3,369 | 3,405 | 3,465 | 3,428 |
| System Service | 188 | 575 | 765 | 1,754 | 2,507 | 2,098 | 1,957 | 1,764 | 1,506 |
| General Plant | 614 | 957 | 1,108 | 848 | 1,056 | 1,178 | 809 | 993 | 1,078 |
| Total | 5,438 | 5,805 | 6,901 | 8,153 | 10,037 | 10,008 | 9,665 | 9,659 | 9,754 |

| Engineering | 2012 Actual $ '000 | 2013 Actual $ '000 | 2014 Actual $ '000 | 2015 Plan $ '000 | 2016 Plan $ '000 | 2017 Plan $ '000 | 2018 Plan $ '000 | 2019 Plan $ '000 | 2020 Plan $ '000 |
|---|---|---|---|---|---|---|---|---|---|
| System Access | 1,954 | 2,134 | 2,240 | 2,281 | 2,603 | 2,587 | 2,711 | 2,634 | 2,768 |
| System Renewal | 262 | 403 | 359 | 1,113 | 1,161 | 1,259 | 1,223 | 1,273 | 1,261 |
| System Service | 224 | 224 | 218 | 465 | 584 | 762 | 587 | 572 | 748 |
| General Plant | 12 | 3 | 57 | - | 2 | - | 3 | 3 | 3 |
| Total | 2,452 | 2,764 | 2,874 | 3,859 | 4,350 | 4,607 | 4,523 | 4,482 | 4,781 |

| All | 2012 Actual $ '000 | 2013 Actual $ '000 | 2014 Actual $ '000 | 2015 Plan $ '000 | 2016 Plan $ '000 | 2017 Plan $ '000 | 2018 Plan $ '000 | 2019 Plan $ '000 | 2020 Plan $ '000 |
|---|---|---|---|---|---|---|---|---|---|
| System Access | 19,888 | 17,030 | 26,229 | 24,145 | 28,232 | 28,470 | 29,561 | 28,726 | 31,867 |
| System Renewal | 16,974 | 22,254 | 39,186 | 42,388 | 48,715 | 51,500 | 52,052 | 52,971 | 52,406 |
| System Service | 13,770 | 34,780 | 17,946 | 27,322 | 38,322 | 32,072 | 29,920 | 26,963 | 23,022 |
| General Plant | 24,200 | 19,593 | 26,148 | 24,545 | 17,631 | 19,558 | 13,967 | 16,841 | 18,206 |
| Total | 74,832 | 93,657 | 109,509 | 118,400 | 132,900 | 131,600 | 125,500 | 125,501 | 125,500 |

**Table VECC 10a.2**

**Proportion**

| Admin/Cap Plan | 2012 Actual % | 2013 Actual % | 2014 Actual % | 2015 Plan % | 2016 Plan % | 2017 Plan % | 2018 Plan % | 2019 Plan % | 2020 Plan % |
|---|---|---|---|---|---|---|---|---|---|
| System Access | 4.9% | 2.7% | 2.6% | 2.3% | 2.5% | 2.6% | 2.8% | 2.7% | 3.0% |
| System Renewal | 1.3% | 1.9% | 2.0% | 2.3% | 2.4% | 2.6% | 2.7% | 2.8% | 2.7% |
| System Service | 0.3% | 0.6% | 0.7% | 1.5% | 1.9% | 1.6% | 1.6% | 1.4% | 1.2% |
| General Plant | 0.8% | 1.0% | 1.0% | 0.7% | 0.8% | 0.9% | 0.6% | 0.8% | 0.9% |
| Total | 7.3% | 6.2% | 6.3% | 6.9% | 7.6% | 7.6% | 7.7% | 7.7% | 7.8% |

| Engineering | 2012 Actual % | 2013 Actual % | 2014 Actual % | 2015 Plan % | 2016 Plan % | 2017 Plan % | 2018 Plan % | 2019 Plan % | 2020 Plan % |
|---|---|---|---|---|---|---|---|---|---|
| System Access | 2.6% | 2.3% | 2.0% | 1.9% | 2.0% | 2.0% | 2.2% | 2.1% | 2.2% |
| System Renewal | 0.3% | 0.4% | 0.3% | 0.9% | 0.9% | 1.0% | 1.0% | 1.0% | 1.0% |
| System Service | 0.3% | 0.2% | 0.2% | 0.4% | 0.4% | 0.6% | 0.5% | 0.5% | 0.6% |
| General Plant | 0.0% | 0.0% | 0.1% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| Total | 3.3% | 3.0% | 2.6% | 3.3% | 3.3% | 3.5% | 3.6% | 3.6% | 3.8% |

*Caution* Please note that the actuals for engineering do not include costs for consultants performing design work whereas the future estimates contain all design costs.

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# **Section III**

**III-Staff-91**

**Ref: T1/S1/p. 185, pp.270 – p. 271 and p. 186**

In the first reference above, PowerStream states that it bills its residential customers on a bi-monthly basis and the rest of the customers on a monthly basis and provides relevant customer numbers. In the second reference, PowerStream states that it intends to move to monthly billing as directed by the OEB and in the third reference provides estimated benefits and costs. On page 271 of the second reference, PowerStream provides information on its e-billing practices.

a) Please describe the Applicant's efforts to promote e-billing to its customers.

b) Please describe other initiatives that the Applicant has undertaken, or intends to undertake, to manage the costs of monthly billing for all customers.

**RESPONSE:**

a) PowerStream has undertaken a number of activities to promote e-billing to its customers:

- Online promotion via the PowerStream website
- Online promotion via Social Media
- Published promotion via the PowerStream Customer newsletter
- Agent promotion on each inbound call as part of our (internal) Call Quality requirements
- Offered to our customers via IVR 'hold' messaging
- Contests

b) In addition to processing a much larger number of bills, monthly billing will also require processing of many more payments. PowerStream plans to undertake a review of payment types to determine the most cost effective method for internal processing and the least costly to customers from both a cost and convenience aspect. From these findings we will promote this method to customers.

**III-Staff-92**

**Ref: /T1/S1/p.206 G-SEC-28 and *Filing Requirements for Electricity Distribution Rate Applications -2015 Edition for 2016 Rates Applications* Chapter 2 Cost of Service July 16, 2015,p.12.**

At the first reference, PowerStream was asked to explain how it modified, if at all, its proposed DS Plan after reviewing the Customer Consultation Report. PowerStream's response was that the plan was not modified after reviewing the Customer Consultation Report.

At the second reference, it is stated that: "The OEB expects distributors to provide an overview of customer engagement activities that the distributor has undertaken with respect to its plans and how customer needs, preferences and expectations have been reflected in the distributor's application."

Given that PowerStream did not modify its DS Plan after reviewing the Customer Consultation Report, please explain why PowerStream believes that this requirement has been met.

**RESPONSE:**

PowerStream determined that customers' preferences were generally in line with the utility's spending priorities and that participants were generally satisfied with the services provided by PowerStream.

For example, most customers were satisfied with the level of reliability they receive from PowerStream. PowerStream's capital expenditure plan is designed to maintain current reliability levels (no degradation). This benefits PowerStream customers by ensuring that the level of reliability with which they are currently satisfied, is maintained. Customers were also satisfied with PowerStream's current practices as they pertain to aging infrastructure and restoration times during outages. In addition, communication enhancements requested by customers had already been implemented by the utility. Therefore, PowerStream did not find it necessary to amend the DS Plan.

**III-Staff-93**

**Ref: T1/S1/p.304, J-SEC-33**

At the above reference PowerStream is asked to state for the purposes of the 2016 to 2020 plan, what assumptions it is making regarding the outcome of the next collective agreement with the PWU.

PowerStream responded that there are no additional assumptions regarding the outcome of the next Collective Agreement in the 2016 to 2020 plan, except the annual inflation assumptions.

Please state in the event that the outcome of the next collective bargaining process was to be significantly different from what is assumed in the Application, whether such an outcome could be expected to have any impacts on the extent of PowerStream's annual rate adjustment filings in the 2016 and subsequent period and, if so, what those impacts might be.

**RESPONSE:**

PowerStream is not proposing any mechanism for true up specific to labour cost increases in connection with employees in the collective bargaining group or any other employee group.

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**III-AMPCO-17**

**Ref: G-AMPCO-5(b)**

Please provide the Kinetrics reports that underlie each presentation provided as Appendix A, B and C.

**RESPONSE:**

The presentations, provided previously, did not have individual reports that supported them, rather one final report was provided by Kinectrics to PowerStream. Refer to AMPCO-8f.

**III-AMPCO-18**

**Ref: G-AMPCO-11(a)**

a) Please explain why the cost to replace a mini-rupter switch in 2015 is significantly greater than in 2014.

b) Please explain how PowerStream determined that 15 mini-rupter switches per year need to be replaced between 2015 and 2020 for a total of 90 replacements.

c) Please confirm the escalator used to calculate the proposed budget for the years 2016 to 2020.

**RESPONSE:**

a) The actual unit cost at each location is affected by the complexity required at a given location, such as the amount of primary cable work, the type of switch being installed (SF6 or Solid Dielectric), the size of the vault room, any requirement to relocate the existing splice to outside of the vault room, switching logistics etc.

b) Currently, there are 123 units that are in Fair condition. It is expected that during the 2015-2020 period, several of these 123 Fair units will move into the Poor and Very Poor condition group and they will be prioritized for replacement in those years.

c) An inflation rate of 2% is used to calculate the proposed budget for the years 2016 to 2020.

**III-AMPCO-19**

**Ref: G-AMPCO-11(b)**

Please explain why the cost to replace an automated switch in 2015 is greater than 2014.

**RESPONSE:**

The actual unit cost at each location is affected by the complexity required at a given location, such as the type of automated device being installed (Recloser or SCADA Mate on 27.6 kV and Motor Operated on 44 kV), the pole condition, existing standards, field installation issues, switching logistics etc.

**III-AMPCO-20**

**Ref: G-AMPCO-11(g)**

a) Please explain the increase in O&M costs in 2014 compared to 2015 for pole testing.

b) Please explain the increase in O&M costs in 2015 compared to 2016 for underground cable testing, dry ice cleaning, infrared scanning and overhead switch maintenance.

**RESPONSE:**

a) The reason for the increase in pole testing from 2014 to 2015 is described below:

| OM&A COSTS | 2014 | 2015 | Increase | | Explanation of increase |
|---|---|---|---|---|---|
| Pole testing | $ 176,290 | $ 185,000 | $ 8,710 | 4.9% | Increase related to inflation and growth in asset base. |

b) The reasons for the increases in 2015 to 2016 is described below:

| OM&A COSTS | 2015 | 2016 | Increase | | Explanation of Increase |
|---|---|---|---|---|---|
| Underground cable testing | $ 51,945 | $ 53,177 | $ 1,232 | 2.4% | Increase driven by the rate per hour escalation above inflation of 1%. |
| Dry ice cleaning | $ 353,295 | $ 356,829 | $ 3,534 | 1.0% | Increase related to inflation. |
| Infrared scanning | $ 146,856 | $ 148,516 | $ 1,660 | 1.1% | Increase related to inflation. |
| Overhead switch maintenance | $ 353,329 | $ 357,419 | $ 4,090 | 1.2% | Increase related to inflation. |

**III-AMPCO-21**

**Ref: G-AMPCO-11(j)**

Please provide a schedule that shows vegetation management costs for overhead lines based on $/km for the years 2011 to 2014 and forecast for 2015 to 2020.

**RESPONSE:**

The table below shows the average OM&A vegetation management cost per km of overhead line for historical and forecast years. This data only reflects dollars spent per linear kilometre of overhead lines and does not take into account the density or type of vegetation, nor the type or extent of tree pruning undertaken.

| | Actual | | | | Forecast Period | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| OM&A - Vegetation Management | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
| Vegetation Management - Annual OM&A Costs (C$) | $1,052,449 | $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 |
| Estimated Overhead (O/H) Lines maintained - Kms | 500 | 500 | 650 | 840 | 840 | 875 | 900 | 900 | 900 | 900 |
| $/Km | $ 2,104.90 | $ 2,455.62 | $ 2,247.74 | $ 2,094.84 | $ 2,452.38 | $ 2,949.26 | $ 3,451.56 | $ 4,041.63 | $ 4,637.60 | $ 5,239.55 |

**III-AMPCO-22**

**Ref: G-AMPCO-19 (d) Appendix D**

The response provides the abstract of the ACA Technical Report on Distribution Switchgear at PowerStream. Please provide the full report.

**RESPONSE:**

Refer to Appendix Staff 71 - ACA Technical Report 2014 (Dec 31 2014).

**III-AMPCO-23**

**Ref: G-AMPCO-28**

Please provide the rationale for increasing the number of projects and spending for Conversion of Rear Lot Overhead from $3.5 million in 2015 to $6 million per year for the years 2016 to 2020.

**RESPONSE:**

As stated in the DS Plan, the ice storm of 2013 produced significant damage to the tree canopy in PowerStream's service territory. It was this damage to the tree canopy that then caused significant damage to the overhead primary and secondary distribution system. The failed trees came down on the power lines causing outages. There were limited pole or transformer failures and those that occurred were generally the result of the weight of the failed tree canopy and not the ice itself.

PowerStream sought to consider ways to effectively "harden" the distribution system against ice storms of this nature and storms in general. These included changes considered to the distribution design standards, upgrade of old systems to present day standards (i.e. rear lot services) and vegetation management practices. A consultant (CIMA) was retained.

One of the major recommendations of the CIMA report is to convert the rear lot overhead supply system to front lot underground supply system. If the electrical components are installed at front lot instead at rear lot, the electrical components would be subject to less risk for tree damage and trouble crews could restore power to the affected customers faster.

Subsequently, PowerStream staff and management discussions confirmed the need for rear lot remediation. It was recommended that the remediation program be implemented over a period of 15 years and hence the funds were increased to cover the program cost.

Refer to response to OEB Staff Question 45 for additional details and the reference to PowerStream's reports.

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**III-CCC-5**

**Ref: Ex. III/T1/S1/p. 12-13/p 23 – A-CCC-10/A-SEC-4**

Please clarify the position of PowerStream regarding what might constitute a re-opening or a termination of the rate plan.

**RESPONSE:**

PowerStream wishes to clarify that its proposal for a trigger amount is the amount shown in the response to A-CCC-10 and not the amount shown in the response to A-SEC-4. PowerStream has nothing further to add to the information it has already provided in the references mentioned above and at Section II, Tab 1, Exhibit A, Tab 1, page 6 ff.

**III-CCC-6**

Please provide a complete description of the billing services that PowerStream provides to Vaughan and Markham, and any other entities. Do the revenues received for these services cover the costs? Did any of these entities contribute to the cost of the new system? If not, why not? What has been assumed with respect to billing revenues beyond 2015? Are there other entities that may be interested in using PowerStream's billing services?

**RESPONSE:**

The billing services that PowerStream provides to Vaughan and Markham include: meter reading, preparation and review of bills, distribution of bills to customers, payment processing, collection activities, customer inquiry activities, reporting and service order processing.

The revenues received reflect the effort involved in the delivery of the services and the related mark-up is included in revenue offsets.

Please refer to the response to IV-VECC-30 in regards to whether Vaughan and Markham contributed to the new system.

A 3% increase in revenues and costs was estimated with respect to these billing revenues beyond 2015.

At this time, we do not know of any other entities that are interested in using PowerStream's billing services.

**III-CCC-7**

**Ref: Ex. III/T1/S1/p. 265 – J-CCC-54**

Please provide the detailed policies regarding PowerStream's executive compensation. Please describe the Performance Incentive Program prove any scorecards that are used for executive compensation.

**RESPONSE:**

PowerStream's Senior Executives are paid a base salary, incentive pay and benefits which all form 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. There are no formal incentive policies.

The Balanced scorecards 2013-2015 used for the Executive incentive plan are included in our application at Section III, Tab 2, A-CCC-12, Appendix A.

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**III-Energy Probe-24**

**Ref: J-Energy Probe-42**

a) The response to part (c) indicates that PowerStream intends to utilize the taxable loses arising in 2015 in that year. Please explain what this means and what the impact on taxes paid in 2015 and previous years is.

b) Is PowerStream entitled to carry the 2015 loss back to previous years in order to receive a refund of previous PILs paid? Please explain fully.

c) Please confirm that the negative taxable income forecast for 2015 includes the impact of the full CCA deduction available for 2015.

d) Please confirm that PowerStream is not required to deduct the full amount of CCA in 2015.

e) Please confirm that if PowerStream reduced the CCA deduction used in 2015 to reduce the taxable income loss to $0, there would be more CCA available to be carried forward into 2016 and subsequent years.

**RESPONSE:**

a) PowerStream will utilize the taxable loss of 2015 by carrying the loss back to prior years as explained in part (b) below. PowerStream will pay no taxes with respect to 2015 but will in effect obtain a refund of the taxes recoverable on the 2015 tax loss by applying the 2015 loss to prior year tax returns to obtain a refund of taxes previously paid.

b) PowerStream is able to carry the 2015 tax loss back up to the three previous tax years to reduce taxable income and taxes payable for those years.

c) Confirmed. This is in accordance with Chapter 2 of the Filing Requirements, Section 2.4.5.2, page 43, which states: “CCA is maximized even if there are tax loss carryforwards.”

d) Not confirmed. Please see the response to part (c).

e) Confirmed.

**III-Energy Probe-25**

**Ref: K-SEC-40**

Please provide the most recent BMO indicative pricing updates for PowerStream for the all in cost of a 10, 20 and 30 year bond.

**RESPONSE:**

Please refer to response II-EP-21 (a).

**III-SEC-10**

**Ref: III/1/1/J-CCC-60**

Please provide an estimate annual OM&A cost savings per year for each 1% increase in e-billing.

**RESPONSE:**

As noted in the response to J-CCC-60 PowerStream estimates a 1% increase in customers being added to e-billing per year. Therefore based on the 1% increase in customers being added to e-billing the 2016-2020 projected OM&A cost savings built into the budget are $20,000 per year.

**III-SEC-11**

**Ref: III/2/G-AMPCO-5b/Appendix A**

Please provide the full report provided by Kinetrics to PowerStream.

**RESPONSE:**

Refer to Appendix AMPCO-8f – PowerStream Asset Condition Assessment Technical Report Phases 1, 2, and 3.

**III-SEC-12**

**Ref: II/F/1/p.7, III/1/1/J-CCC-30**

Please provide an update on the implementation of new CIS system. Please detail any implementation issues that have arisen.

**RESPONSE:**

The new CIS went into service on May 25, 2015. The system is fully operational, performing well and creating accurate customer bills. All necessary system interfaces and meter to cash functionalities are working consistent with the project objectives.

We did not experience any major technical issues during project implementation. The system and the interfaces were thoroughly tested in the development phase prior to implementation. This testing and validation of critical functionality helped to ensure a smooth implementation. As with any major IT project, there were some non-impactive implementation issues. They were identified and resolved in a timely manner. For example, an issue relating to converted meter reading data from the legacy CIS system was identified and resolved during project implementation.

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**III-VECC-11**

**Ref: Section III/G-AMPCO-6/E-G/T2/5.2.3**

a) Section 5.2.3 of the Distribution System Plan lists various performance measurements. In other places in the application other metrics are provided. Please provide a comprehensive table listing all metrics which PowerStream intends to report on annually as part of this rate plan.

b) For each metric listed above, please add a column which shows the annual target or objective for the noted metric.

c) For each annual target/objective please add a column which describes the consequence (e.g. on future rates or employee compensation), of failing to meet, meeting, or exceeding the metric target. .

**RESPONSE:**

a) The measures referred to in this interrogatory are the internal processes that underpin achieving the desired outcomes and the reporting described in the response to II-1-Staff-8.

b) Please see the response to part (a) of this interrogatory.

c) Please see the response to III-VECC-13.

**III-VECC-12**

**Ref: Section III/T4/Schedule 1/BOMA-11**

The following table is found at page 5 of 43 of the above noted reference

| Year | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|
| SAIDI Upper Limit (Minutes) | (84.10) | (82.87) | (82.67) | (82.64) | (81.07) | (81.07) |
| SAIDI target | 69.26 | 68.02 | 64.69 | 61.54 | 59.97 | 59.97 |

2: Five year Reliability Targets

a) Please confirm that these targets are used for the purpose of the proposed rate plan.

b) Please indicate what, if any consequence there is of failing to meet these targets.

**RESPONSE:**

a) These targets are derived based on the capital and the system renewal plan submitted. These targets are used for the purposes of the proposed rate plan.

b) Reliability is one of the metrics on the corporate balanced score card. Failure to meet the targets affects the end of year corporate scoring.

**III-VECC-13**

**Ref: Section III/A-CCC-3**

a) In response to A-CCC-3 PowerStream states that it proposes to use the Board's scorecard as its outcome measures. Please explain how the outcomes of the Scorecard will impact rate setting or employee compensation, or describe what other consequences arise during the plan based on the Scorecard results.

**RESPONSE:**

a) PowerStream's understanding is that the Board will use the scorecard to monitor PowerStream's performance and determine if it is delivering on its plan. If the Board feels that PowerStream is not delivering on its plan, it may ask for explanations and for the corrective actions being undertaken.

Incentive pay is part of management employees' compensation packages. Many of the goals under the incentive performance plans for these employees are directly or indirectly related to achievement of results that are reflected in the Board's scorecard.

**III-VECC-14**

**Ref: Section III/G-VECC-15 / Section VI/T4/S1/pg.3**

a) At Section VI PowerStream states that it "*proposes capital and OM&A spending to improve system reliability and make its system more resistant to outages caused by storms*". Please explain what metrics are being tracked and reported on which will demonstrate whether this objective is met during the course of the proposed rate plan. Please be specific.

**RESPONSE:**

a) Metrics 1, 2, 3 and 7, as stated under 5.2.3. Performance Measurement for Continuous Improvement, Exhibit G Tab 2 Page 2, will be reported and tracked to demonstrate that the objective is met during the course of the proposed rate plan. Specifically, the CEA cause codes for adverse weather, adverse environment and tree contact can be measured, with and without MEDs to gain further insight.

**III-VECC-15**

**Ref: Section III/T4/Schedule 1/BOMA-11/Appendix A**

a) PowerStream has completed a 5 Year Work Reliability Work Plan. Please explain how this plan is monitored for effectiveness.

b) The Reliability Work Plan contains detailed metrics and with specific objectives. Are these metrics and target outcomes part of PowerStream's rate plan proposal? If yes, please explain how the rate plan is impacted by these metrics.

**RESPONSE:**

a) PowerStream's Reliability Committee monitors the execution of the projects and tracks the performance of the system, the system reliability and effectiveness of the programs.

b) The reliability work plan is developed based on the capital and the OM&A submitted and the related CMI avoidance and reliability improvements. Metric 1, 2, 3 and 7 as listed under 5.2.3. Performance Measurement for continuous reporting Exhibit G Tab 2 Page 2 will be reported and tracked to demonstrate that the objective is met during the course of the proposed rate plan.

These metrics will be impacted if the rate plan/DS Plan is not executed.

**III-VECC-16**

**Ref: Section III/T4/S1/BOMA-11/pg.10**

a) PowerStream has identified five cause codes as being controllable (1,3,5 & 8). For the years 2011 through 2014 please provide the percentage of SAIDI and SAIFI (excluding MEDs and Loss of Supply). Please provide the results in both tabular and graph form.

**RESPONSE:**

a) Refer to Table VECC 16.1 and Table VECC 16.2 below, as well as Figure VECC 16.2 and VECC 16.2 below.

**Table VECC 16.1, Figure VECC 16.1**

| Controllable SAIDI 2011-2014 (Excl: LOS & MED) | | | | | | | |
|---|---|---|---|---|---|---|---|
| Cause | | | Percentage of Total SAIDI | | | | |
| | Cause Code | Description | 2011 | 2012 | 2013 | 2014 | 2011-2014 Avg. |
| Controllable | 1 | Scheduled Outage | 7% | 7% | 11% | 12% | 9% |
| | 3 | Tree Contact | 3% | 5% | 10% | 5% | 6% |
| | 5 | Defective Equipment | 51% | 49% | 52% | 41% | 48% |
| | 8 | Human Element | 0% | 1% | 3% | 1% | 1% |
| | Controllable Total | | 61% | 62% | 76% | 59% | 64% |

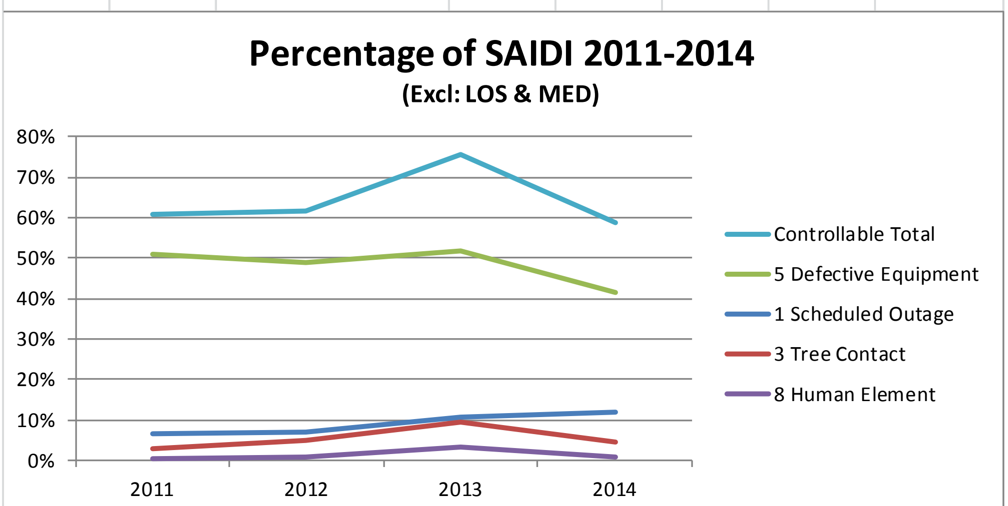
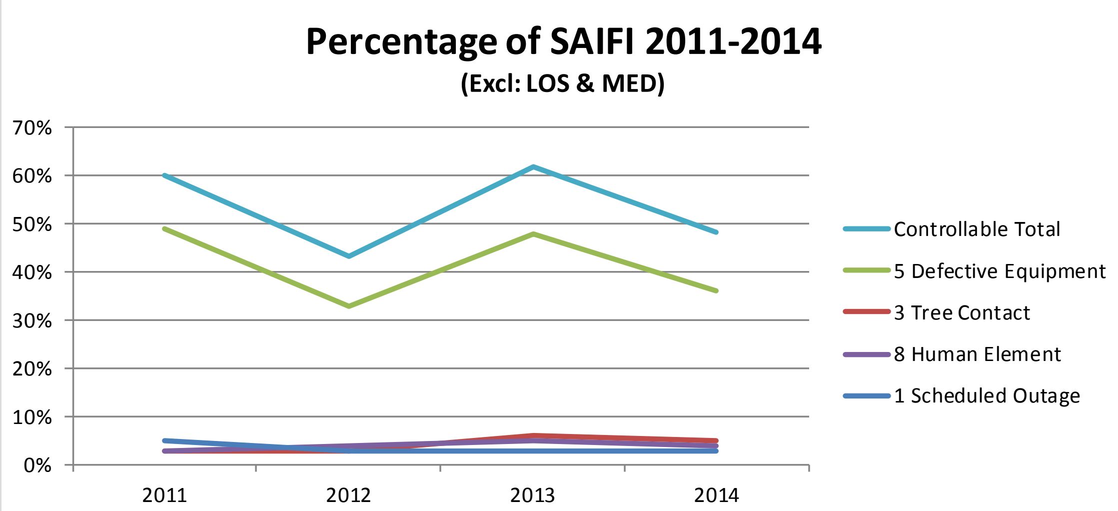


**Table VECC 16.2, Figure VECC 16.2**

| Controllable SAIFI 2011-2014 (Excl: LOS & MED) | | | | | | | |
|---|---|---|---|---|---|---|---|
| Cause | | | Percentage of Total SAIFI | | | | |
| | Cause Code | Description | 2011 | 2012 | 2013 | 2014 | 2011-2014 Avg. |
| Controllable | 1 | Scheduled Outage | 5% | 3% | 3% | 3% | 4% |
| | 3 | Tree Contact | 3% | 3% | 6% | 5% | 4% |
| | 5 | Defective Equipment | 49% | 33% | 48% | 36% | 42% |
| | 8 | Human Element | 3% | 4% | 5% | 4% | 4% |
| | | Controllable Total | 60% | 43% | 62% | 48% | 53% |



**III-VECC-17**

**Ref: Section III/T4/S1/BOMA-11/pg.18/Appendix A**

a) Please reconcile the projects listed in Appendix A (1-13) with the proposed capital budget for the period 2016-2012. If the amounts proposed to be spent on these projects is different, please revise Table to show the costs, CMI and SAIDI Savings and cost per CMI for the proposed rate plan

**RESPONSE:**

a) PowerStream assumes this question is meant to cover the years 2016-2020. Refer to Appendix VECC-17. A new table has been provided.

**III–VECC-18**

**Ref: SECTION III/TAB 1/SCHEDULE 1, H-EP #21 a), c) and d); H-EP #22 a); H-EP #25 a), b) and c); H-EP #26 a); and H-VECC #22 a)**

a) For purposes of the current proceeding's record, please provide the Excel spreadsheets associated with the responses to each of the pre-application interrogatories referenced above as provided with the original responses.

b) Please provide a "live" version of the Excel spreadsheet for EP #21 d) where the predicted values from each class' equation are not shown as set values but shown as being calculated using the proposed regression model for each class and the independent variables.

c) Please provide a "live" version of the Excel spreadsheet for EP #25 c) where the calculation of predicted 2015-2020 counts for each class are shown (using the class' equation and the forecast values for the independent variables) rather than as just a set value.

**RESPONSE:**

a) To clarify, we believe some of the reference in this IR was incorrect, for example, H-EP#22 a) should read H-EP#22 b); and H-VECC#22 a) should read H-VECC#22 c).

Please refer to III-VECC-18 appendices for the original live Excel spreadsheets related to the above noted pre-application interrogatories.

b) Please refer to III-VECC-18-Appendix A (Load Forecast) Live Excel for the above request.

c) Please refer to III-VECC-18-Appendix B (Customer Counts Forecast) Live Excel for the above request.

**III–VECC-19**

**Ref: SECTION III/TAB 1/SCHEDULE 1, H-VECC #21**

a) When was the economic forecast provided by the Conference Board of Canada (per VECC d)) prepared?

b) Is a more recent forecast available? If so, please provide the updated forecast in the same format as Appendix H-1-1.

c) If the response to part (b) is affirmative, please provide an updated forecast, including an updated version of H-EP #21 d).

d) As part of its recent long-term forecast for Ontario, did the OPA produce regional long-term energy forecasts (i.e. for total load)? If so, please provide the OPA's long term (2014-2020) energy forecast for the region encompassing PowerStream's service area and provide the supporting reference(s).

**RESPONSE:**

a) The economic forecast provided by the Conference Board of Canada was prepared in December 2014.

b) Yes. PowerStream obtained the latest economic forecast from the Conference Board of Canada which was prepared in early August this year. Please see III-VECC-19-Appendix A for the updated economic forecast.

c) Please see III-VECC-19-Appendix B for the updated load forecast in a live Excel workbook.

d) Having consulted with the IESO (OPA) with respect to this matter, they advised that the IESO produced zonal forecasts for the 10 IESO zones as part of the LTEP2013 process. The IESO did not produce forecasts specifically for the areas serviced by PowerStream. PowerStream's customers are located in more than one zone. The only readily available documentation is the Provincial level discussion for LTEP2013.

**III–VECC-20**

**Ref: E-H/T1, pg. 1 & 3**
**SECTION III/TAB 1/SCHEDULE 1, H-VECC #21**
**EB-2015-0004 (Ottawa Hydro), Exhibit C/Itron Report, pg. 4 & 13-14**

a) It is noted that Itron supported the preparation of the load forecasts for both PowerStream's and Ottawa Hydro's 2016 Customer IR Applications. Are the historical and forecast values for the Residential Energy Intensity variable used in both applications the same? If not, why not?

**RESPONSE:**

a) Yes. The historical and forecasted residential end-use energy intensities used in the PowerStream and Hydro Ottawa forecasts are the same. The residential end-use intensities are derived from end-use saturation and annual end-use energy estimates (UEC) provided by the OPA. This data was generated as part of OPA's long-term energy forecast for Ontario (*2013 Long-Term Energy Plan, Achieving Balance: Ontario's Long-Term Energy Plan).*

**III–VECC–21**

**Ref: E-H/T2, pg. 3 and Appendix H-3-1, pg. 2**
**SECTION IV/TAB 1/UNDERTAKING #27 & #28-1**
**SECTION III/TAB 1/SCHEDULE 1, H-EP-25 c)**

a) Please explain how the historical values for the AR(1) variable, as used in the Residential customer count equation estimation, are determined and provide a schedule setting out the monthly values for 2008-2014.

b) Please provide a live Excel Spreadsheet that sets out the calculation of predicted monthly Residential customer count values for 2008-2014 based on the proposed equation and the values for the independent variables.

c) Please confirm that the forecast values for AR(1) are set out in the EP 25 c) Excel Spreadsheet, Residential Equation Tab, Column E. If not, please indicate where the values can be found and/or provide.

d) Please explain how the forecast values for AR(1) as used in the Residential equation were determined.

e) Please explain how the historical values for the AR(1) variable, as used in the GS<50 customer count equation estimation, are determined and provide a schedule setting out the monthly values for 2008-2014.

f) Please provide a live Excel Spreadsheet that sets out the calculation of predicted monthly GS<50 customer count values for 2008-2014 based on the proposed equation and the values for the independent variables.

g) Please confirm that the forecast values for AR(1) are set out in the EP 25 c) Excel Spreadsheet, GS<50 Equation Tab, Column E. If not, please indicate where the value can be found and/or provide.

h) Please explain how the forecast values for AR(1) as used in the GS<50 equation were determined.

**RESPONSE:**

a) The AR(1) term is not a model input. It is calculated as part of the model estimation process that relates monthly customer counts to the monthly population series. The auto-regressive correction term is an option in the regression modeling object.

Actual customer counts are strongly correlated with population. The correlation coefficient between the population and number of customers is 0.999. This indicates that population is a strong variable for explaining customer growth. While the population variable is highly significant in the residential customer forecast model, the forecast model has strong first order serial correlation with a DW Statistic of 0.20. The AR(1) term corrects for serial correlation.

While there are no AR(1) input values, the model does generate contribution of the AR(1) term to predicted residential customers. III-VECC-21-Appendix A shows the predicted residential customer, and the contribution to the predicted values by population and the AR(1) term for the estimation period (2008 to 2014).

b) The only independent value is population. The Excel Spreadsheet III-VECC-21-Appendix B shows the model calculations. For comparison, both the predicted before and after the AR(1) correction are included. The first model shows the results before correcting for serial correlation. The predicted value (column E) is derived by multiplying the population estimate by the model coefficient without AR(1) correction (cell S6). The residual is calculated by subtracting the predicted value from the actual value (column F); the error is shown on a percent basis in column G. The mean absolute percent error (the average of the absolute errors) is 1.25%.

The AR(1) model is shown in columns J through O. Column J shows the predicted value before the AR(1) adjustment; this is calculated by multiplying the population coefficient from the AR model (cell S7) by the population estimate. Column K shows the initial model residual. Column L shows the AR(1) correction; this is derived by multiplying AR(1) coefficient (cell S8) times the residual in the prior month. The adjusted predicted customers are shown in column M and the new residual and percent residuals are shown in columns N and O. The mean absolute percent error with the AR(1) correction is 0.06%.

The AR(1) correction results in a slightly higher coefficient on the population variable and a stronger in-sample model fit with the MAPE improving from 1.25% to 0.06%.

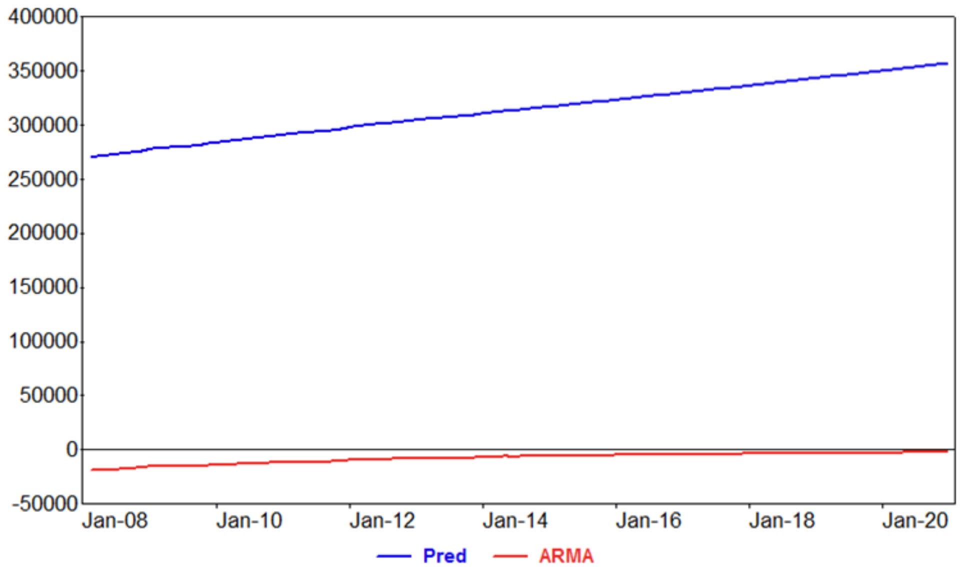
c) Yes. The Excel tab “residential equation” Column E shows the contribution of the AR(1) term to the predicted customer value. The AR(1) term is not an exogenous model variable, but is calculated as part of the model estimation and forecast generation process.

d) The impact of the AR(1) term is determined by the estimated model coefficients on population and the specified AR(1) term – it is not a forecasted exogenous variable. MetrixND shows the contribution of the AR(1) term to the forecasted values. The calculation starts by applying the AR(1) coefficient to the last residual of the actual data series (before

AR1 adjustment). The adjustment is then carried forward into the forecast period by applying the AR(1) coefficient to remaining residual in the prior period:

AR(1)t = AR1 Coef * AR1t-1

As the AR(1) coefficient is less than 1, the impact declines over the forecast period. The figure below shows the contribution of the AR(1) term over time.




e) The AR(1) variable is derived by specifying the model with an AR(1) correction term. The values shown for the AR(1) term represent the contribution of the AR term to the monthly predicted value.

While there are no AR(1) input values, the model does generate contribution of the AR(1) term to predicted residential customers. The Excel file III-VECC-21-Appendix E shows the predicted GS<50 customers, and the contribution to the predicted values by the number of residential customers and the AR(1) term for the estimation period (2008 to 2014).

f) Please see III-VECC-21-Appendix F for the model calculations. The only model input (exogenous variable) are the number of residential customers. There is a strong correlation between the number of small commercial customers (GS<50) and the number of residential customers; the correlation coefficient between the number of residential customers and small commercial customers is 0.984 (1.00 is perfect correlation). The AR(1) term and its contribution to the predicted value is derived from the model specification; the model includes an AR(1) term to correct for serial correlation. The first model shows the calculations before correcting for serial correlation. The predicted value (column E) is derived by multiplying the residential customer count by the model coefficient without AR(1) correction (cell S7). The residual is calculated by subtracting the predicted value from the actual value (column F); the error is shown on a percent basis in column G. The mean absolute percent error (the average of the absolute errors) is 0.56%.

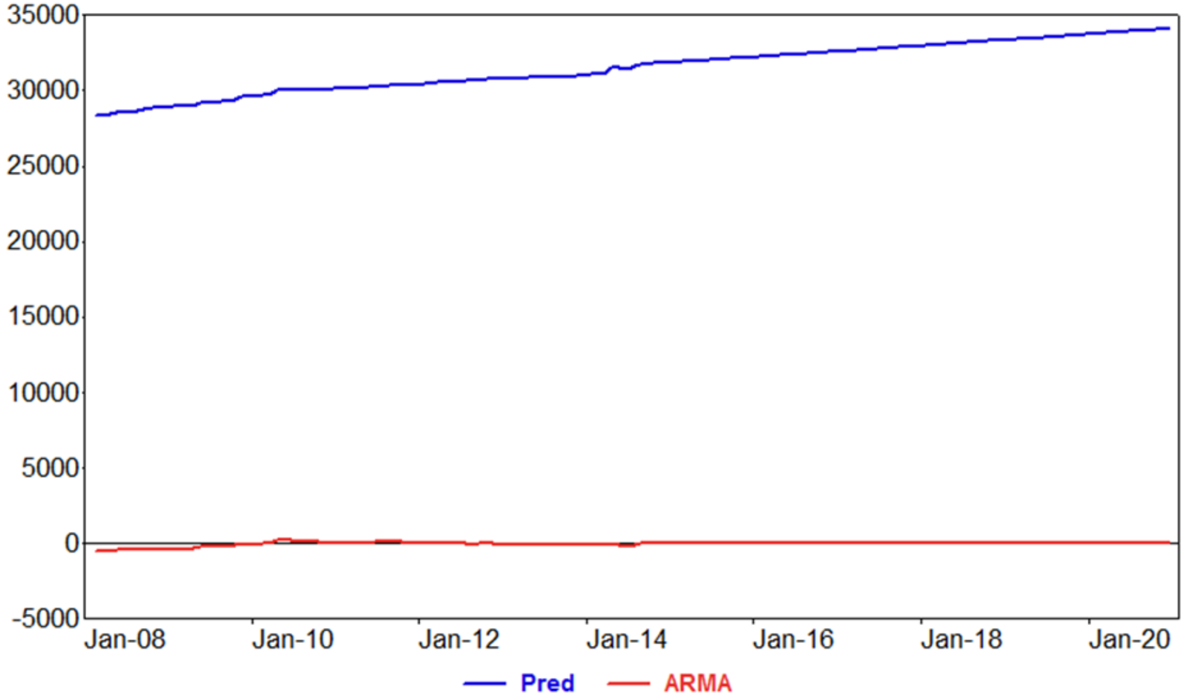
The AR(1) model is shown in columns  Column J shows the predicted value before the AR(1) adjustment; this is calculated by multiplying the population coefficient from the AR model (cell T7) by the population estimate. Column K shows the initial model residual. Column L shows the AR(1) correction; this is derived by multiplying AR(1) coefficient (cell T8) times the residual in the prior month. The adjusted predicted small commercial customers are shown in column M and the new residual and percent residuals are shown in columns N and O. The mean absolute percent error (MAPE) with the AR(1) correction is 0.12%. The estimates derived from the software are slightly different than the calculations shown in the spreadsheet largely a result of rounding the coefficients and the iterative AR(1) calculation method illustrated in the spreadsheet. The model MAPE derived in the software is 0.10% compared with 0.12% calculated in the spreadsheet.

g) Yes. The Excel tab “GS<50_Equation” Column G shows the contribution of the AR(1) term to the predicted customer value. The AR(1) term is not an exogenous model variable, but is calculated as part of the model estimation and forecast generation process.

h) The impact of the AR(1) term is determined by the estimated model coefficients and the specified AR(1) term; the AR(1) term is not a forecasted exogenous variable. MetrixND shows the contribution of the AR(1) term to the forecasted values. The calculation starts by applying the AR(1) coefficient to the last residual of the actual data series (before AR1 adjustment). The adjustment is then carried forward into the forecast period by applying the AR(1) coefficient to remaining residual in the prior period:

$AR(1)_t = AR1\ Coef * AR1_{t-1}$

As the AR(1) coefficient is less than 1, the impact declines over the forecast period. The figure below shows the contribution of the AR(1) term over time.


35000
30000
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Jan-20
Pred
ARMA

**III–VECC-22**

**Ref: SECTION III/TAB 1/SCHEDULE 1, H-EP #21 and #25**

a) It is noted that for purposes of the load forecast a portion of the forecast residential customer count and load was transferred to the GS>50 class on the basis that these customers would be "suite metered" by 3rd party suite metering providers. Please outline how the number of customers to be transferred in each year was determined and how the kWh to transferred were subsequently established.

**RESPONSE:**

a) The average annual addition in residential suite-metered customers is about 1,436, calculated based on the latest 3 year average (2012-2014). Given the trend of new condominiums in PowerStream's service area opting for submetering, the assumption was that the addition for suite-metered customers for PowerStream will be reduced to 500 each year starting in 2015. Assuming approximately 250 units for one bulk meter, the lost addition in residential suite-metered customers, in 2015 for instance, will add an additional four GS>50 customers in our total customer counts.

The subsequent kWh transfer is calculated by using the number of residential suite-metered customers (lost to submetering providers) multiplied by their average annual consumption (3,391kWh) in the last 3 years (2012-2014).

**III–VECC-23**

**Ref: E-H/T2, pg. 1-3**
**SECTION III/TAB 1/SCHEDULE 1, H-VECC #26**
**E-H/Appendix H-2-1**

a) Please provide a copy of the PowerStream's most recent plan, as submitted to the OPA/IESO, for meeting its 2015-2020 CDM targets.

b) Please confirm that the 2015-2020 annualized CDM savings, as set out in VECC #26 d), are consistent with PowerStream's most recent plan. If not, please update VECC #26 c) and d).

c) Please explain how the total CDM savings by year (per E-H/T2, Table 2) were assigned to customer classes and provide a schedule that sets out class specific values for each year 2015-2019.

d) Please reconcile the 2011-2014 CDM savings set out in Appendix H-2-1 with the OPA Reported results (Table 5) per VECC #26.

**RESPONSE:**

a) Please see III-VECC-23 Appendix A for PowerStream's CDM plan as submitted to the OPA/IESO, for meeting its 2015-2020 CDM targets.

b) PowerStream confirms that the 2015-2020 annualized CDM savings, as set out in VECC#26 d), are consistent with PowerStream's most recent plan.

c) The CDM program/initiative was assigned to customer classes based on percent allocation as seen in the past. For example, in retrofit, we historically have 14% of the participants are GS<50 customers. Therefore, the same allocation has been applied in the forecast. Please see II-1-Staff-21-Appendix A for the schedule sets out class specific values for each year (2015-2020).

d) Please see III-VECC-23 Appendix B for the reconciliation regarding to 2011-2014 CDM savings set out in Appendix H-2-1 with the OPA Reported results (Table 5) per VECC#26.

**III–VECC-24**

**Ref: E-H/T4, pg. 1**
**SECTION III/TAB 1/SCHEDULE 1, H-VECC #27**

a) Were the historic kW/kWh ratio applied to the GWh forecasts after the CDM adjustment?

b) If not, how were the impact of CDM on the billing determinants for the GS>50, Large Use, Street Lighting and Sentinel Lighting determined?

**RESPONSE:**

a) Yes. The historic kW/kWh ratio was applied to the GWh forecasts after the CDM adjustment.

b) Please see the response to part a), above.

**III–VECC–25**

**Ref: E-H/T2, pg. 3 and Appendix H-2-1**
**SECTION III/TAB 1/SCHEDULE 1, H-VECC #26**

a) Please provide a schedule setting out PowerStream's proposed 2016-2019 LRAMVA kWh by customer class consistent with its proposed load forecast.

b) Please explain why the manual adjustment for LED Street Lighting is not included in the proposed LRAMVA kWh.

c) Please provide a revised response to part (a) which includes the adjustments for LED Street Lighting as part of the LRAMVA kWh values.

**RESPONSE:**

a) Please see the table below for PowerStream's proposed 2015-2020 CDM kWh reduction by customer class as per the proposed load forecast. This represents the forecast savings for comparison to the achieved savings in the future LRAMVA true-up calculations.

| | Residential | GS<50 | GS>50 | Total |
|---|---|---|---|---|
| **2015** | 2,226,378 | 4,907,745 | 18,904,920 | 26,039,043 |
| **2016** | 11,818,293 | 15,315,943 | 57,546,526 | 84,680,763 |
| **2017** | 32,226,368 | 26,548,154 | 98,935,434 | 157,709,956 |
| **2018** | 60,426,521 | 39,127,836 | 148,575,840 | 248,130,197 |
| **2019** | 99,429,767 | 52,846,816 | 203,967,533 | 356,244,116 |
| **2020** | 138,275,868 | 66,612,056 | 259,643,400 | 464,531,325 |
| **Total** | **344,403,196** | **205,358,549** | **787,573,654** | **1,337,335,399** |

b) Please see H-Energy Probe–23 (Section III, Tab1, Schedule 1, page 222)

c) Please see the table below which was inserted with the manual adjustment for LED Street Lighting, as requested.

However, PowerStream doesn't believe this is an appropriate approach. The CDM plan was submitted and approved by the IESO/OPA in December 2014. The LED conversion is not part of the approved CDM plan, for the reason explained in H-Energy Probe-23. As such, the LED Street Lighting adjustment should not be blended and mixed into the 2015-2020 CDM forecast savings which are the basis for comparison to the actual achieved savings in future LRAMVA true-up calculations.

Any true-up to the manual adjustment for Street Lighting must be compared to actual LED savings regardless of whether they are part of the OPA program or not.

| kWh | Residential | GS<50 | GS>50 | Street lighting | Total |
|---|---|---|---|---|---|
| **2015** | 2,226,378 | 4,907,745 | 18,904,920 | | 26,039,043 |
| **2016** | 11,818,293 | 15,315,943 | 57,546,526 | 12,289,507 | 96,970,269 |
| **2017** | 32,226,368 | 26,548,154 | 98,935,434 | 14,506,119 | 172,216,075 |
| **2018** | 60,426,521 | 39,127,836 | 148,575,840 | 16,694,164 | 264,824,361 |
| **2019** | 99,429,767 | 52,846,816 | 203,967,533 | 16,694,455 | 372,938,571 |
| **2020** | 138,275,868 | 66,612,056 | 259,643,400 | 16,651,174 | 481,182,499 |
| **Total** | **344,403,196** | **205,358,549** | **787,573,654** | **76,835,419** | **1,414,170,817** |

**III–VECC–26**

**Ref: SECTION III/TAB 1/SCHEDULE 1, I-EP #28 d) and G-VECC #19 c)**

a) Do Revenue Offsets as currently proposed by PowerStream include either the correction noted in EP #28 d) or the additional potential revenue identified in VECC #19 c)?

**RESPONSE:**

a) In relation to the correction noted in Energy Probe - 8, yes the Revenue Offsets as currently proposed by PowerStream in the May rate application include the correction noted, which is the inclusion of account "4355 Gain on Disposition of Utility and Other Property" in revenue offsets.

The additional potential revenue identified in VECC #19 c) regarding the potential leasing options at the Barrie location has not been incorporated as a revenue offset. The Barrie office renovation is still ongoing. No firm plans have been made to lease out this facility. The response to VECC #19c) was based on preliminary advice from an external consultant as to the average lease rates in this area. Once the renovation is complete and PowerStream has determined that the space is not required to support its business operations, the matter will be reassessed at this time. It is not expected that lease options, if applicable, would be acted upon prior to 2017.

**III–VECC-27**

**Ref: SECTION III/TAB 1/SCHEDULE 1, H-VECC 26 a) & e) and N-VECC #40**

a) With respect to Table N-VECC-40-10, is the 6.5 conversion factor used for converting peak demand savings to billing kW meant to capture the impact of the ½ year rule?

b) For the 2013 non-DR programs, what would the billing kW be if calculated using the kWh savings attributed to the GS>50 class (including reductions for the ½ year adjustment) and the kW/kWh ratio used in the Exhibit H to convert the forecast GS>50 kWh to kW?

c) With respect to Table N-VECC-40-10, please explain why the 2013 persisting saving for the Residential 2012 CDM programs is the same as the initial 2012 reported savings reported by the OPA (VECC #26 a)) when Table 5 of the OPA Report shows a decline in persistence in 2013 for the 2012 CDM programs.

**RESPONSE:**

a) PowerStream confirms that the 6.5 conversion factor is used to capture the impact of the ½ year rule. This is illustrated in Tables III-VECC-27-1 and III-VECC-27-2 below.

**Table III-VECC-27-1: Conversion Summary**

| | GS>50 Rate Classification | | |
|---|---|---|---|
| | 2013 kW | 2013 kW (net of DR3) | 2013 Converted to Billable kW Net kW Savings X 6.5 |
| ERIP: Retrofit | 4,744 | 4,744 | 30,838 |
| New Construction and Major Renovation | 778 | 778 | 5,057 |
| Energy Audit | 79 | 79 | 514 |
| Energy Manager | 421 | 421 | 2,737 |
| Program Enabled Savings | 5 | 5 | 33 |
| Business Refrigeration | 2 | 2 | 10 |
| ERIP: pre-2011 | 0 | 0 | 0 |
| High Performance New Construction: pre-2011 | 14 | 14 | 92 |
| DR3 | 8,327 | | 0 |
| GS>50 Total | 14,370 | 6,043 | 39,279 |

The annual reduction of 6,043 kW demand is added at an average rate of 504 kW demand reduction per month. Table III-VECC-27-2 shows how this affects the monthly kW amounts billed.

### Table III-VECC-27-2: Application of ½ Year Rule

| | 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 | 3,021 |
| 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 |
| Total | 504 | 1,007 | 1,511 | 2,014 | 2,518 | 3,021 | 3,525 | 4,029 | 4,532 | 5,036 | 5,539 | 6,043 | 39,279 |

b) Table III-VECC-27-3 shows the result of converting the OPA kWh savings to kWs billed reduction by using the ratio of kWhs to billable kWs used in Exhibit H.

### Table III-VECC-27-3: Details by CDM Initiative, 2013 (kWh)

| | GS>50 Rate Classification | | | | | | |
|---|---|---|---|---|---|---|---|
| | 2011 kWh | 2012 kWh | 2013 kWh | 2011-2012 Persistence 2011 - 95%, 2012 - 100% | 2013 kWh Half-Year-Rule | 2011-2013 Total kWh | |
| ERIP: Retrofit | 10,324,148 | 25,550,321 | 27,131,061 | 35,358,261 | 13,565,531 | 48,923,792 | |
| New Construction and Major Renovation | 39,886 | 0 | 1,579,613 | 37,892 | 789,807 | 827,698 | |
| Energy Audit | 25,176 | 276,939 | 436,057 | 300,856 | 218,029 | 518,885 | |
| Energy Manager | 0 | 36,000 | 3,717,682 | 36,000 | 1,858,841 | 1,894,841 | |
| Program Enabled Savings | 5,574 | 1,234,217 | 7,515 | 1,239,512 | 3,758 | 1,243,270 | |
| Business Refrigeration | 0 | 0 | 14,994 | 0 | 7,497 | 7,497 | |
| ERIP: pre-2011 | 2,016,889 | 0 | 0 | 1,916,045 | 0 | 1,916,045 | |
| High Performance New Construction: pre-2011 | 308,772 | 466,781 | 37,726 | 760,114 | 18,863 | 778,977 | |
| DR3 | | | 185,992 | 0 | 92,996 | 92,996 | |
| GS>50 Total | 12,720,445 | 27,564,258 | 33,110,640 | 39,648,681 | 16,555,320 | 56,204,001 | |
| GS>50 (without DR3) | 12,720,445 | 27,564,258 | 32,924,648 | 39,648,681 | 16,462,324 | 56,111,005 | A |
| | | | | | Apply kW/kWH Ratio (Exhibit H) | 0.27% | B |
| | | | | | Converted kW Demand (non-Demand programs) | 151,500 | A x B |

c) PowerStream's modelling assumption is that the previous year savings will persist in the current year at 100%. There is a decline in persistence starting the following year. For example, 2012 reported savings are going to persist at a 100% in 2013, while 2011 reported savings will be realized at 95% of the originally reported value.

**III-VECC-28**

**Ref: Section III/N-VECC-40**

a) Please confirm that the kW savings values reported for the Demand Response 3 program are contracted values and not actual demand reductions in each year.

b) Does PowerStream have any record as to how much actual demand reduction was achieved in each year due to the Demand Response 3 program? If so, how much was the actual demand reduction in each year and was the demand reduction coincident with the peak interval used to establish the customers' billing demands?

**RESPONSE:**

a) PowerStream confirms that the kW savings values reported in N-VECC-40-1 for the Demand Response 3 ("DR3") program are contracted values. According to the OPA methodology of calculating resource savings, they represent "ex ante" estimates based on the load reduction capability that can be expected for the purposes of planning.

b) PowerStream does not have any records as to how much actual demand reduction was achieved in each year due to the DR3 program. PowerStream uses the peak demand reductions listed in the OPA report as the basis for calculating its lost revenue adjustment variance.

In order to calculate the demand reduction that was achieved in each year due to the DR3 program for the purposes of LRAMVA, PowerStream assumed that the billed demand was reduced by the OPA-reported peak demand savings in each of the three months from June through August. OPA defines hours of DR3 availability as 12:00 PM to 9:00 PM on weekdays during all summer months and the OPA-reported amount is the average reduction in peak demand at this time. Most customers' peak demand is likely to occur within this time interval thus creating the overall system peak the OPA is seeking to reduce. Accordingly PowerStream has assumed that the demand reduction is coincident with the peak interval used to establish the customer's billing demand.

Under the DR3 program, program participants agree to make a firm commitment to reduce energy use during periods of peak demand and they are expected to fulfill their contractual obligations for energy savings under the program. Financial set-offs are applied for failure to perform during an activation.

The DR3 program issues activation notices when there is the need to reduce the system demand for power. Such events are typically due to a majority of customers demanding more electricity than they normally do, such as significant increases in the demand for energy due to air-conditioning load. Table III-VEC-28-1 below summarizes the 2011-2012 DR3 activation notices issued by the OPA.

**Table III-VECC-28-1: 2011-2012 DR3 Activation Notices**

| Event Date | Event Start | Event End |
|---|---|---|
| 5/31/2011 | 3:45 PM | 7:45 PM |
| 6/6/2011 | 2:45 PM | 6:45 PM |
| 6/7/2011 | 2:45 PM | 6:45 PM |
| 6/8/2011 | 2:45 PM | 6:45 PM |
| 7/11/2011 | 1:45 PM | 5:45 PM |
| 7/21/2011 | 2:45 PM | 6:45 PM |
| 7/22/2011 | 2:45 PM | 6:45 PM |
| 8/2/2011 | 1:45 PM | 5:45 PM |
| 8/4/2011 | 3:45 PM | 7:45 PM |
| 11/21/2011 | 3:45 PM | 7:45 PM |
| 11/22/2011 | 3:45 PM | 7:45 PM |
| Total DR3 Activation Instances in 2011 | 11 | |
| 6/20/2012 | 1:45 PM | 5:45 PM |
| 6/21/2012 | 1:45 PM | 5:45 PM |
| 7/17/2012 | 2:45 PM | 6:45 PM |
| 9/5/2012 | 2:45 PM | 6:45 PM |
| 9/6/2012 | 2:45 PM | 6:45 PM |
| Total DR3 Activation Instances in 2012 | 5 | |

There were 11 activation notices in 2011, which occurred in May, June, July, August and November, affecting a total of 5 months. There were 5 activation notices in 2012, which occurred in June, July and September, affecting a total of 3 months.

The actual performance during DR3 activation notices for DR3 Program participants is confidential information and is not publically available. Participants will normally reduce their energy use during the activation because of the contractual obligation to curtail and the financial consequences of not performing. Note that the OPA adjusts its estimate of the actual demand reductions based on past history to reflect that some participants may not be able to deliver the full contracted reduction all of the time.

The OPA-reported Net Peak Demand Savings (kW) are counted as progress towards 2011-2014 OPA Contracted Province-Wide CDM Programs. The reductions reported by the OPA are the best available data for use in calculating the lost revenue.

On the days where most of the DR3 activation hours occur, for many customers it is likely that the peak demand without reduction, driven by the high air-conditioning load, would be significantly higher than the peak demand on days where there are no activations. It is reasonable to assume that under these circumstances the peak reductions will coincide with what would have been the customer's monthly peak demand, thereby reducing the billed demand for the month. In the case of several activations within the same month (e.g. July 2011 – 3 activations) it is very likely that not only the peak (highest) monthly demand has been reduced but even the second and third highest demands. The difference between the peak demand before reduction and the $4^{th}$ highest peak demand would be an even greater differential than the peak demand before reduction and the $2^{nd}$ highest demand in the month. The reduction in billed demand may be less than 100% of the OPA reported demand reduction but it is very unlikely that it is 0%.

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# Section IV

**IV-AMPCO-24**

**Ref: Technical Conference Undertaking (TCQ) #1**

a) Please provide the 2015 year to date OM&A and Capital Actuals and the forecast to year end.

**RESPONSE:**

a) Please refer to the response to I-SEC-23 which shows table's 2-JA and 2-JB (OM&A and OM&A cost drivers) comparing 2014 to 2015 YTD actuals. The forecast for 2015 is that we will meet our budget.

Please refer to the response to I-Staff-4c for capital actuals and forecast to the year end.

**IV-AMPCO-25**

**Ref: Technical Conference Undertaking (TCQ) #17**

a) Please complete a similar table that shows the population and condition of each asset in 2011 and the number of units replaced for each of the years 2011 to 2014.

b) Please discuss the asset condition trend for each asset type from 2011 to 2015.

**RESPONSE:**

a) The population and condition of each asset in 2011 and the number of units replaced for each of the years 2011 to 2014 are shown in the Table AMPCO-25a below.

In 2011, ACA analyses were not conducted for TS Station Service Transformers, 230kV Primary Metering Units, TS P&C Relays, Mini-Rupter Switches, Automated Switches and Wood Poles.

**Table AMPCO-25a**

| Asset | Population | Condition | | | | Number of Units Replaced (Planned Replacement) | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Good | Fair | Poor | N/A | 2011 | 2012 | 2013 | 2014 | Total |
| TS Power Transformers | 22 | 22 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| MS Power Transformers | 65 | 63 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 |
| TS and MS Station Circuit Breakers | 399 | 337 | 0 | 49 | 13 | 10 | 7 | 5 | 4 | 26 |
| TS 230kV Primary Switches | 22 | 22 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| MS Primary Switches | 66 | 66 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TS Capacitor Banks | 5 | 4 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TS Reactors | 34 | 34 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TS Station Service | Note 1 | Note 1 | Note 1 | Note 1 | Note 1 | 0 | 0 | 0 | 0 | 0 |
| 230kV Primary Metering Units | Note 1 | Note 1 | Note 1 | Note 1 | Note 1 | 0 | 0 | 0 | 0 | 0 |
| TS P&C Relays(2) | Note 1 | Note 1 | Note 1 | Note 1 | Note 1 | 23 | 2 | 2 | 6 | 33 |
| Underground Cable | 7,836 (km) | 5,226 | 1,198 | 1,412 | 0 | 9.6<br>10.3 | 25.1<br>9.1 | 85.4<br>49.5 | 107<br>54.5 | 227(3)<br>123(4) |
| Distribution Transformers | 43,535 | 10,294 | 6,789 | 3,858 | 22,594 | 20 | 32 | 78 | 77 | 207 |
| Switchgear | 1,739 | 631 | 209 | 69 | 830 | 12 | 7 | 20 | 50 | 89 |
| Mini-Rupter Switches | Note 1 | Note 1 | Note 1 | Note 1 | Note 1 | 0 | 0 | 0 | 21 | 21 |
| Automated Switches | Note 1 | Note 1 | Note 1 | Note 1 | Note 1 | 0 | 0 | 5 | 5 | 10 |
| Wood Poles | 46,414 | Note 1 | Note 1 | Note 1 | Note 1 | 117 | 315 | 368 | 453 | 1,253 |

Notes:

(1) Not available for year 2011.

(2) Feeder Relay replacements have not been included since they were not included in the reported inventory as of December 31, 2014. Included are Relays associated with line, bus, transformer and capacitor bank protections.

(3) 227 km of Cable injection.

(4) 123 km of Cable Replacement.

b) There has been a slight worsening in numeric Health Index scores for all station asset categories since 2011, however, no material change has been seen in the TS and MS transformers. Missing Asset Health Index information has been gathered for station and distribution assets since 2011. ACA models have been created for TS Station Service Transformers, 230kV Primary Metering Unit, TS P&C Relays, Mini-Rupter Switches, Automated Switches since 2011.

The amount of underground cable population within the poor category (based on age) has increased over 67% from 2011.

For Distribution Transformers and Switchgear, the numbers of units rated in “Poor” condition has increased.

**IV-AMPCO-26**

**Ref: Technical Conference Undertaking (TCQ) #32**

a) Please add a line to the table to show actual overtime costs for the years 2011 to 2014 and provide 2015 year to date actuals.

b) Please explain any variances greater than 10%.

c) Please provide PowerStream's overtime hours as a percent of regular hours for the years 2011 to 2014.

d) Please discuss if PowerStream has an annual target for overtime hours as a percent of regular hours.

e) Please confirm overtime is typically paid at double time.

**RESPONSE:**

a) Please see the table IV-AMPCO-26-1 below.

**Table IV-AMPCO-26-1: Actual vs. Budgeted Overtime Costs**

| | 2011 | 2012 | 2013 | 2014 | Jan - Jun 2015 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Budget** | 2,239,426 | 2,542,844 | 2,870,725 | 2,620,264 | 1,298,359 | 2,596,718 | 2,704,847 | 2,734,972 | 2,785,969 | 2,842,366 | 2,896,170 |
| **Actual** | 4,175,761 | 3,501,559 | 3,326,569 | 4,456,709 | 1,879,287 | | | | | | |
| **Variance** | 86% | 38% | 16% | 70% | 45% | | | | | | |

b) The variances between actual and forecast are mainly due to higher than budgeted reactive activity resulting from the need to restore or replace failed distribution equipment due to uncontrollable events such as storm and accident damage.

c) Please see the Table IV-AMPCO-26-2 below.

**Table IV-AMPCO-26-2: Overtime Hours as Percent of Regular Hours**

| 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|
| 6% | 5% | 4% | 6% |

d) PowerStream does not have an annual target for overtime hours as a percentage of regular hours.

Confirmed that PowerStream staff is typically paid two times their base rate for overtime.

**IV-SEC-13**

**Ref: IV/1/p.24/Undertaking 24**

With respect to the use of external contractors for capital projects:

a. For the purpose of determining the forecast capital expenditures, what assumptions did PowerStream make regarding use of internal versus external contractors?

b. Please provide a summary of the structure of PowerStream's arrangements with external contractors for capital projects.

**RESPONSE:**

a. Depending on the department and type of work required, a mix of internal and external consulting and or contractors are used.

b. Refer to G-SEC-27, found on Sec 3, Tab 1, Schedule 1, Pg 204 of 363, lines 15-38.

**IV-SEC-14**

**Ref: IV/1/p.24/Undertaking 24**

PowerStream states "the hours estimated for PowerStream's crews and the actual hours completed using the external contractor's crew were very close". Please provide the numerical basis for the conclusion that numbers were "very close".

**RESPONSE:**

The 3 projects compared are detailed in Table SEC-14 below.

**Table SEC-14**

| | Hours | |
|---|---|---|
| Project # | Contractor Actual | PowerStream Estimate |
| 1 | 148 | 146 |
| 2 | 180 | 185 |
| 3 | 972 | 996 |

**IV–VECC–29**

**Ref: E-H/Appendix H-1-3, pg. 11-13**
**SECTION III/TAB 1/SCHEDULE 1, H-VECC #25 c)**
**SECTION IV/TAB 1/UNDERTAKING #28-2**

a) The response to Undertaking 28-2 states that 65% of the streetlights in PowerStream's service territories are owned by the City of Vaughan, Markham and Barrie. However, the response to VECC #25 c) indicates that the % of HPS lights owned by these three municipalities is 53%. Please reconcile.

b) Based on the municipalities' current plans is it still appropriate to assume that the conversion to LED will be completed over the 2016-2019 period? If not, what are the appropriate revised assumptions?

c) Please provide a schedule that sets out (based on the pre-CDM adjustment load forecast for Street Lighting) the total kWh in each year (2015-2019), the number of connections and the resulting usage per connection.

d) Please reconcile the pre-CDM per connection forecast from part c) with the assumed pre-CDM use of 727 kWh per Undertaking 28-2 used to calculate the impact of conversion to LED.

e) Based on the foregoing responses please revise the estimated impact of the LED Street Light conversion (Appendix H-1-3, page 13) as required.

**RESPONSE:**

a) 65% of the streetlights in PowerStream's service territories are owned by the Cities of Vaughan, Markham and Barrie, of which, 12% were already LED as of December 2014. These 12% LED streetlights are owned by the City of Markham.

The 53% is referring to HPS lights that are owned by the Cities of Vaughan (22%), Markham (18%) and Barrie (13%).

b) No. Based on the current plans, Markham, Barrie and New Tecumseth will complete their LED Street Lighting upgrades by December 2015. The assumption on the LED conversion plan for the City of Vaughan remains unchanged.

c) Please see table below for the schedule requested:

| Year | SL Load Fcst kWh | SL Connections Fcst | Usage per Connection |
|---|---|---|---|
| 2015 | 60,109 | 87,377 | 688 |
| 2016 | 59,956 | 88,954 | 674 |
| 2017 | 60,109 | 90,576 | 664 |
| 2018 | 60,109 | 92,207 | 652 |
| 2019 | 60,109 | 93,857 | 640 |
| 2020 | 59,956 | 95,547 | 628 |

d) The 727 kWh per Undertaking 28-2 was derived from average annual usage per connection over the period from 2012 to 2014. The Usage per Connection in the table above in c) is based on the load and connection forecast for 2015-2020.

e) Please see table below for revised LED Street Lighting conversion impact (Appendix H-1-3, page 13) as required.

| Year | Actual/Forecast Before LED Adjustment | LED Adjustment | Actual/Forecast after LED Adjustment | % Change |
|---|---|---|---|---|
| **2008** | 55,677 | **0** | 55,677 | |
| **2009** | 56,744 | **0** | 56,744 | 1.9% |
| **2010** | 58,367 | 0 | 58,367 | 2.9% |
| **2011** | 59,196 | 0 | 59,196 | 1.4% |
| **2012** | 60,735 | 0 | 60,735 | 2.6% |
| **2013** | 61,302 | 0 | 61,302 | 0.9% |
| **2014** | 60,168 | 0 | 60,168 | -1.8% |
| **2015 Bridge Year** | 60,109 | 0 | 60,109 | -0.1% |
| **2016 Test Year** | 59,956 | - 12,290 | 47,666 | -20.7% |
| **2017 Test Year** | 60,109 | - 14,506 | 45,603 | -4.3% |
| **2018 Test Year** | 60,109 | - 16,694 | 43,415 | -4.8% |
| **2019 Test Year** | 60,109 | - 16,694 | 43,415 | 0.0% |
| **2020 Test Year** | 59,956 | - 16,651 | 43,305 | -0.3% |

**IV–VECC -30**

**Ref: SECTION IV/TAB 1/UNDERTAKING #29 & #41**
**SECTION III/TAB 1/SCHEDULE 1, B-CCC 14 & 15**

a) It is noted that the water billing contracts with both Vaughan and Markham expire December 31, 2015 (UNDERTAKING #29). What assumptions were made regarding the future pricing of water billing services in forecasting water billing revenues (UNDERTAKING #41)?

b) Did these assumptions include an increase in water billing service charges to help cover the incremental costs associated with the 2014& 2015 CIS investments? If not, why not?

**RESPONSE:**

a) A 3% year-over-year increase in revenues and costs were assumed when determining the future pricing of water billing services in forecasting water billing revenues.

b) No, these assumptions did not include an increase in water billing service charges to help cover the incremental costs associated with 2014 & 2015 investments. The need for the new customer care and billing system was driven by the requirement for updated electricity billing functionality. There was no additional functionality purchased for water billing and water billing leverages the core electricity billing functionality. As such, there are no incremental costs related solely to water billing.

**IV–VECC-31**

**Ref: Cost Allocation Models (2016-2020)**
**E-H/Appendix H-4-1**
**SECTION IV/TAB 1/UNDERTAKING #28-2**

a) The Cost Allocation model reports (Tab I6.2) the number of Street Light connections for 2016 as 30,634 and the number of devices as 88,226. However, UNDERTAKING #28-2 reports the number of connections for 2016 as 88,226. Please reconcile.

**RESPONSE:**

In the cost allocation model, Tab I6.2, 30,634 is the number of physical connections in PowerStream's system. In undertaking #28-2, 88,226 represents the number of street lights which is the basis for billing.

## Section V

**V-Staff-94**

**Ref: T3**

At the above reference PowerStream provides bill impacts for various rate classes and consumption levels.

a) Please explain why the Ontario Clean Energy Benefit is not included as part of the 2015 bill even though it remains in effect in 2015.

b) Please recalculate bill impacts for the residential class at 800 kWh consumption and GS< 50, 2,000 kWh class for 2016 incorporating the OCEB in 2015.

**RESPONSE:**

a) This was a clerical error on PowerStream's behalf.

b) PowerStream has recalculated the Residential bill impacts to include OCEB for 2015 in the updated bill impacts are presented in Section A, Application Update, Tab 2, Schedule 2.

**V-Staff-95**

**Ref: T3/S1**

Upon completing all interrogatories from OEB staff and intervenors, please provide an updated Appendix 2-W for all classes at the typical consumption / demand levels (e.g. 800 kWh for residential, 2,000 kWh for GS<50, etc.).

**RESPONSE:**

An updated Appendix 2-W for all classes at the typical consumption/demand levels is presented in Section C, Tab 1, V-Staff-95 Appendix A.

**V–VECC-32**

**Ref: E-M/T1, pg. 1-3**
**SECTION V/TAB 1/SCHEDULE 1, PG. 8-9**

a) Please update Tables 1 to 7 from Exhibit M, Tab 1 of the February materials be reflect the updated revenue requirements and cost allocations.

b) Please indicate what the 2016 monthly fixed charge would be if the Residential revenue requirement was recovered entirely through a fixed monthly service charge.

c) Please indicate what the 2016 Residential monthly service charge would be, assuming the current (2015) fixed charge was increased ¼ of the way to this value.

d) Please provide the resulting Residential 2016 total bill impacts (i.e. the Residential tables in Appendix 2-W) if this service charge (per part (c)) was adopted and the variable charge decreased accordingly for the following monthly kWh usage levels: 250; 500; 800; 1,000; 1,500 and 2,000.

e) Based on the most recent 12 months of billing data please indicate how many Residential customers fall into each of the following average monthly use categories:
   - 0-100 kWh
   - >100-250 kWh
   - >250-500 kWh
   - >500-800 kWh
   - >800-1,000 kWh
   - >1,000-1,500 kWh
   - >1,500-2,000 kWh
   - >2,000 kWh

**RESPONSE:**

a) Please refer to Section A, Tab 1, Schedule 1, Application Update item number 8. This section contains the requested tables.

As part of this application, PowerStream applied the fixed-variable rate design for

Residential rate classification in accordance with the Board's letter from July 16, 2015 on *"Implementing a New Rate Design for Electricity Distributors (OEB File No. EB-2012-0410)".*

b) For the purpose of responding to this interrogatory, PowerStream calculated the 2016 monthly fixed charge under the scenario when the Residential revenue requirement is recovered entirely through a fixed monthly service charge.

| | | |
|---|---|---|
| | Total Revenue Requirement | $187,023,489 |
| | Resdential Share (Cost allocation) | 54.1% |
| A | Residential Revenue Requirement | $101,115,222 |
| B | Forecasted Customers | 325,345 |
| A/B/12 | Fixed MSC | **$25.90** |

c) For the purpose of responding to this interrogatory, PowerStream calculated the 2016 monthly fixed charge under the scenario when the current (2015) fixed charge is increased ¼ of the way to this value.

| | | |
|---|---|---|
| A | Current (2015) MSC | $12.67 |
| B | Full Fixed MSC | $25.90 |
| C = (B - A) / 4 | 1/4 increase | $3.31 |
| A + C | 2016 MSC | **$15.98** |

d) For the purpose of responding to this interrogatory, PowerStream calculated the resulting Residential 2016 total bill impacts. Variable rate calculations are presented in the Exhibit below.

| | | |
|---|---|---|
| A | Residential RR | $101,115,222 |
| | # of Customers | 325,345 |
| | Fixed MSC | **$15.98** |
| B | Fixed Revenue | $62,377,867 |
| C = A - B | Variable Revenue | $38,737,355 |
| D | Consumption (kWh) | 2,714,896,670 |
| C / D | Variable Rate | **$0.0143** |

The 2016 bill impacts are presented below.

# Table V-VECC-32-1: 2016 Bill Impacts – 100 kWh Consumption

| | | | 2015 Current Board-Approved | | | 2016 TEST YEAR 1 Proposed | | Impact 2016 TEST vs. 2015 Bridge | |
|---|---|---|---|---|---|---|---|---|---|
| | Charge Unit | Volume | Rate ($) | Charge ($) | | Rate ($) | Charge ($) | $ Change | % Change |
| Monthly Service Charge | Monthly | 1 | $ 12.67 | $ 12.67 | | $ 15.98 | $ 15.98 | $ 3.31 | 26.1% |
| Smart Meter Rate Adder | Monthly | 1 | $ - | $ - | | $ - | $ - | $ - | |
| Recovery of CGAAP/CWIP Differential | Monthly | 1 | $ 0.20 | $ 0.20 | | $ 0.20 | $ 0.20 | $ - | 0.0% |
| ICM Rate Rider (2014) | Monthly | 1 | $ 0.07 | $ 0.07 | | $ - | $ - | $ (0.07) | -100.0% |
| | | 1 | $ - | $ - | | $ - | $ - | $ - | |
| | | 1 | $ - | $ - | | $ - | $ - | $ - | |
| Distribution Volumetric Rate | per kWh | 100 | $ 0.0140 | $ 1.40 | | $ 0.0143 | $ 1.43 | $ 0.03 | 1.9% |
| Smart Meter Disposition Rider | per kWh | 100 | $ - | $ - | | $ - | $ - | $ - | |
| LRAM & SSM Rate Rider | per kWh | 100 | $ - | $ - | | $ - | $ - | $ - | |
| ICM Rate Rider (2014) | per kWh | 100 | $ 0.0001 | $ 0.01 | | $ - | $ - | $ (0.01) | -100.0% |
| Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) | per kWh | 100 | $ 0.0001 | $ 0.01 | | $ - | $ - | $ (0.01) | -100.0% |
| Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2016) | per kWh | 100 | $ - | $ - | | -$ 0.0001 | $ (0.01) | $ (0.01) | |
| Recovery of Stranded Meter Assets (2016) | per kWh | 100 | $ - | $ - | | $ 0.0001 | $ 0.01 | $ 0.01 | |
| Account 1575 | per kWh | 100 | $ - | $ - | | -$ 0.0005 | $ (0.05) | $ (0.05) | |
| | | 100 | $ - | $ - | | $ - | $ - | $ - | |
| | | 100 | $ - | $ - | | $ - | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 14.36 | | | $ 17.55 | $ 3.19 | 22.2% |
| Deferral/Variance Account Disposition Rate Rider (2014) | per kWh | 100 | -$ 0.0006 | $ (0.06) | | $ - | $ - | $ 0.06 | -100.0% |
| Disposition of Deferral/Variance Accounts (2016) | per kWh | 100 | $ - | $ - | | $ 0.0002 | $ 0.02 | $ 0.02 | |
| | | 100 | $ - | $ - | | $ - | $ - | $ - | |
| | | 100 | $ - | $ - | | $ - | $ - | $ - | |
| Low Voltage Service Charge | per kWh | 100 | $ 0.0003 | $ 0.03 | | $ 0.0005 | $ 0.05 | $ 0.02 | 66.7% |
| Line Losses on Cost of Power | | 3.45 | $ 0.1021 | $ 0.35 | 3.69 | $ 0.1021 | $ 0.38 | $ 0.02 | 7.0% |
| Smart Meter Entity Charge | Monthly | 1 | $ 0.7900 | $ 0.79 | | $ 0.7900 | $ 0.79 | $ - | |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 15.47** | | | **$ 18.79** | $ 3.32 | **21.4%** |
| RTSR - Network | per kWh | 103 | $ 0.0080 | $ 0.83 | 104 | $ 0.0080 | $ 0.83 | $ 0.00 | 0.2% |
| RTSR - Line and Transformation Connection | per kWh | 103 | $ 0.0035 | $ 0.36 | 104 | $ 0.0037 | $ 0.38 | $ 0.02 | 6.0% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 16.66** | | | **$ 20.00** | $ 3.34 | **20.1%** |
| Wholesale Market Service Charge (WMSC) | per kWh | 103 | $ 0.0044 | $ 0.46 | 104 | $ 0.0044 | $ 0.46 | $ 0.00 | 0.2% |
| Rural and Remote Rate Protection (RRRP) | per kWh | 103 | $ 0.0013 | $ 0.13 | 104 | $ 0.0013 | $ 0.13 | $ 0.00 | 0.2% |
| Standard Supply Service Charge | Monthly | 1 | $ 0.25 | $ 0.25 | | $ 0.2500 | $ 0.25 | $ - | 0.0% |
| Debt Retirement Charge (DRC) | per kWh | 100 | $ 0.0070 | $ 0.70 | | | $ - | $ (0.70) | -100.0% |
| TOU - Off Peak | per kWh | 64 | $ 0.0800 | $ 5.12 | | $ 0.0800 | $ 5.12 | $ - | 0.0% |
| TOU - Mid Peak | per kWh | 18 | $ 0.1220 | $ 2.20 | | $ 0.1220 | $ 2.20 | $ - | 0.0% |
| TOU - On Peak | per kWh | 18 | $ 0.1610 | $ 2.90 | | $ 0.1610 | $ 2.90 | $ - | 0.0% |
| | | | | | | | | | |
| **Total Bill on TOU (before Taxes)** | | | | **$ 28.42** | | | **$ 31.06** | $ 2.64 | **9.3%** |
| HST | | | 13% | $ 3.69 | | 13% | $ 4.04 | $ 0.34 | 9.3% |
| **Total Bill** (including HST) | | | | $ 32.11 | | | $ 35.10 | $ 2.99 | 9.3% |
| ***Ontario Clean Energy Benefit* [1]** | | | 10% | -$ 3.21 | | | | $ 3.21 | -100.0% |
| **Total Bill on TOU (including OCEB)** | | | | **$ 28.90** | | | **$ 35.10** | $ 6.20 | **21.4%** |

**Loss Factor (%)** 3.45% 3.69%

## Table V-VECC-32-2: 2016 Bill Impacts – 250 kWh Consumption

| | | | 2015 Current Board-Approved | | | 2016 TEST YEAR 1 Proposed | | Impact 2016 TEST vs. 2015 Bridge | |
|---|---|---|---|---|---|---|---|---|---|
| | Charge Unit | Volume | Rate ($) | Charge ($) | | Rate ($) | Charge ($) | $ Change | % Change |
| Monthly Service Charge | Monthly | 1 | $ 12.67 | $ 12.67 | | $ 15.98 | $ 15.98 | $ 3.31 | 26.1% |
| Smart Meter Rate Adder | Monthly | 1 | $ - | $ - | | $ - | $ - | $ - | |
| Recovery of CGAAP/CWIP Differential | Monthly | 1 | $ 0.20 | $ 0.20 | | $ 0.20 | $ 0.20 | $ - | 0.0% |
| ICM Rate Rider (2014) | Monthly | 1 | $ 0.07 | $ 0.07 | | $ - | $ - | $ (0.07) | -100.0% |
| | | 1 | $ - | $ - | | $ - | $ - | $ - | |
| | | 1 | $ - | $ - | | $ - | $ - | $ - | |
| Distribution Volumetric Rate | per kWh | 250 | $ 0.0140 | $ 3.50 | | $ 0.0143 | $ 3.57 | $ 0.07 | 1.9% |
| Smart Meter Disposition Rider | per kWh | 250 | $ - | $ - | | $ - | $ - | $ - | |
| LRAM & SSM Rate Rider | per kWh | 250 | $ - | $ - | | $ - | $ - | $ - | |
| ICM Rate Rider (2014) | per kWh | 250 | $ 0.0001 | $ 0.03 | | $ - | $ - | $ (0.03) | -100.0% |
| Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) | per kWh | 250 | $ 0.0001 | $ 0.03 | | $ - | $ - | $ (0.03) | -100.0% |
| Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2016) | per kWh | 250 | $ - | $ - | | -$ 0.0001 | $ (0.03) | $ (0.03) | |
| Recovery of Stranded Meter Assets (2016) | per kWh | 250 | $ - | $ - | | $ 0.0001 | $ 0.03 | $ 0.03 | |
| Account 1575 | per kWh | 250 | $ - | $ - | | -$ 0.0005 | $ (0.13) | $ (0.13) | |
| | | 250 | $ - | $ - | | $ - | $ - | $ - | |
| | | 250 | $ - | $ - | | $ - | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 16.49 | | | $ 19.62 | $ 3.13 | 19.0% |
| Deferral/Variance Account Disposition Rate Rider (2014) | per kWh | 250 | -$ 0.0006 | $ (0.15) | | $ - | $ - | $ 0.15 | -100.0% |
| Disposition of Deferral/Variance Accounts (2016) | per kWh | 250 | $ - | $ - | | $ 0.0002 | $ 0.05 | $ 0.05 | |
| | | 250 | $ - | $ - | | $ - | $ - | $ - | |
| | | 250 | $ - | $ - | | $ - | $ - | $ - | |
| Low Voltage Service Charge | per kWh | 250 | $ 0.0003 | $ 0.08 | | $ 0.0005 | $ 0.13 | $ 0.05 | 66.7% |
| Line Losses on Cost of Power | | 8.63 | $ 0.1021 | $ 0.88 | 9.22 | $ 0.1021 | $ 0.94 | $ 0.06 | 7.0% |
| Smart Meter Entity Charge | Monthly | 1 | $ 0.7900 | $ 0.79 | | $ 0.7900 | $ 0.79 | $ - | |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 18.09** | | | **$ 21.53** | $ 3.44 | **19.0%** |
| RTSR - Network | per kWh | 259 | $ 0.0080 | $ 2.07 | 259 | $ 0.0080 | $ 2.07 | $ 0.00 | 0.2% |
| RTSR - Line and Transformation Connection | per kWh | 259 | $ 0.0035 | $ 0.91 | 259 | $ 0.0037 | $ 0.96 | $ 0.05 | 6.0% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 21.06** | | | **$ 24.56** | $ 3.50 | **16.6%** |
| Wholesale Market Service Charge (WMSC) | per kWh | 259 | $ 0.0044 | $ 1.14 | 259 | $ 0.0044 | $ 1.14 | $ 0.00 | 0.2% |
| Rural and Remote Rate Protection (RRRP) | per kWh | 259 | $ 0.0013 | $ 0.34 | 259 | $ 0.0013 | $ 0.34 | $ 0.00 | 0.2% |
| Standard Supply Service Charge | Monthly | 1 | $ 0.25 | $ 0.25 | | $ 0.2500 | $ 0.25 | $ - | 0.0% |
| Debt Retirement Charge (DRC) | per kWh | 250 | $ 0.0070 | $ 1.75 | | | $ - | $ (1.75) | -100.0% |
| TOU - Off Peak | per kWh | 160 | $ 0.0800 | $ 12.80 | | $ 0.0800 | $ 12.80 | $ - | 0.0% |
| TOU - Mid Peak | per kWh | 45 | $ 0.1220 | $ 5.49 | | $ 0.1220 | $ 5.49 | $ - | 0.0% |
| TOU - On Peak | per kWh | 45 | $ 0.1610 | $ 7.25 | | $ 0.1610 | $ 7.25 | $ - | 0.0% |
| | | | | | | | | | |
| **Total Bill on TOU (before Taxes)** | | | | **$ 50.07** | | | **$ 51.82** | $ 1.75 | **3.5%** |
| HST | | | 13% | $ 6.51 | | 13% | $ 6.74 | $ 0.23 | 3.5% |
| **Total Bill** (including HST) | | | | $ 56.58 | | | $ 58.56 | $ 1.98 | 3.5% |
| ***Ontario Clean Energy Benefit*** [1] | | | 10% | -$ 5.66 | | | | $ 5.66 | -100.0% |
| **Total Bill on TOU (including OCEB)** | | | | **$ 50.92** | | | **$ 58.56** | $ 7.64 | **15.0%** |

| | | |
|---|---|---|
| **Loss Factor (%)** | 3.45% | 3.69% |

1 **Table V-VECC-32-3: 2016 Bill Impacts – 500 kWh Consumption**

| | Charge Unit | Volume | 2015 Current Board-Approved Rate ($) | 2015 Current Board-Approved Charge ($) | Volume | 2016 TEST YEAR 1 Proposed Rate ($) | 2016 TEST YEAR 1 Proposed Charge ($) | Impact 2016 TEST vs. 2015 Bridge $ Change | Impact 2016 TEST vs. 2015 Bridge % Change |
|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | Monthly | 1 | $ 12.67 | $ 12.67 | | $ 15.98 | $ 15.98 | $ 3.31 | 26.1% |
| Smart Meter Rate Adder | Monthly | 1 | $ - | $ - | | $ - | $ - | $ - | |
| Recovery of CGAAP/CWIP Differential | Monthly | 1 | $ 0.20 | $ 0.20 | | $ 0.20 | $ 0.20 | $ - | 0.0% |
| ICM Rate Rider (2014) | Monthly | 1 | $ 0.07 | $ 0.07 | | $ - | $ - | $ (0.07) | -100.0% |
| | | 1 | $ - | $ - | | $ - | $ - | $ - | |
| | | 1 | $ - | $ - | | $ - | $ - | $ - | |
| Distribution Volumetric Rate | per kWh | 500 | $ 0.0140 | $ 7.00 | | $ 0.0143 | $ 7.13 | $ 0.13 | 1.9% |
| Smart Meter Disposition Rider | per kWh | 500 | $ - | $ - | | $ - | $ - | $ - | |
| LRAM & SSM Rate Rider | per kWh | 500 | $ - | $ - | | $ - | $ - | $ - | |
| ICM Rate Rider (2014) | per kWh | 500 | $ 0.0001 | $ 0.05 | | $ - | $ - | $ (0.05) | -100.0% |
| Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) | per kWh | 500 | $ 0.0001 | $ 0.05 | | $ - | $ - | $ (0.05) | -100.0% |
| Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2016) | per kWh | 500 | $ - | $ - | | -$ 0.0001 | $ (0.05) | $ (0.05) | |
| Recovery of Stranded Meter Assets (2016) | per kWh | 500 | $ - | $ - | | $ 0.0001 | $ 0.05 | $ 0.05 | |
| Account 1575 | per kWh | 500 | $ - | $ - | | -$ 0.0005 | $ (0.25) | $ (0.25) | |
| | | 500 | $ - | $ - | | $ - | $ - | $ - | |
| | | 500 | $ - | $ - | | $ - | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 20.04 | | | $ 23.06 | $ 3.02 | 15.1% |
| Deferral/Variance Account Disposition Rate Rider (2014) | per kWh | 500 | -$ 0.0006 | $ (0.30) | | $ - | $ - | $ 0.30 | -100.0% |
| Disposition of Deferral/Variance Accounts (2016) | per kWh | 500 | $ - | $ - | | $ 0.0002 | $ 0.10 | $ 0.10 | |
| | | 500 | $ - | $ - | | $ - | $ - | $ - | |
| | | 500 | $ - | $ - | | $ - | $ - | $ - | |
| Low Voltage Service Charge | per kWh | 500 | $ 0.0003 | $ 0.15 | | $ 0.0005 | $ 0.25 | $ 0.10 | 66.7% |
| Line Losses on Cost of Power | | 17.25 | $ 0.1021 | $ 1.76 | 18.45 | $ 0.1021 | $ 1.88 | $ 0.12 | 7.0% |
| Smart Meter Entity Charge | Monthly | 1 | $ 0.7900 | $ 0.79 | | $ 0.7900 | $ 0.79 | $ - | |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 22.44** | | | **$ 26.09** | $ 3.64 | **16.2%** |
| RTSR - Network | per kWh | 517 | $ 0.0080 | $ 4.14 | 518 | $ 0.0080 | $ 4.15 | $ 0.01 | 0.2% |
| RTSR - Line and Transformation Connection | per kWh | 517 | $ 0.0035 | $ 1.81 | 518 | $ 0.0037 | $ 1.92 | $ 0.11 | 6.0% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 28.39** | | | **$ 32.15** | $ 3.76 | **13.2%** |
| Wholesale Market Service Charge (WMSC) | per kWh | 517 | $ 0.0044 | $ 2.28 | 518 | $ 0.0044 | $ 2.28 | $ 0.01 | 0.2% |
| Rural and Remote Rate Protection (RRRP) | per kWh | 517 | $ 0.0013 | $ 0.67 | 518 | $ 0.0013 | $ 0.67 | $ 0.00 | 0.2% |
| Standard Supply Service Charge | Monthly | 1 | $ 0.25 | $ 0.25 | | $ 0.2500 | $ 0.25 | $ - | 0.0% |
| Debt Retirement Charge (DRC) | per kWh | 500 | $ 0.0070 | $ 3.50 | | | $ - | $ (3.50) | -100.0% |
| TOU - Off Peak | per kWh | 320 | $ 0.0800 | $ 25.60 | | $ 0.0800 | $ 25.60 | $ - | 0.0% |
| TOU - Mid Peak | per kWh | 90 | $ 0.1220 | $ 10.98 | | $ 0.1220 | $ 10.98 | $ - | 0.0% |
| TOU - On Peak | per kWh | 90 | $ 0.1610 | $ 14.49 | | $ 0.1610 | $ 14.49 | $ - | 0.0% |
| | | | | | | | | | |
| **Total Bill on TOU (before Taxes)** | | | | **$ 86.16** | | | **$ 86.43** | $ 0.27 | **0.3%** |
| HST | | | 13% | $ 11.20 | | 13% | $ 11.24 | $ 0.03 | 0.3% |
| **Total Bill** (including HST) | | | | $ 97.36 | | | $ 97.66 | $ 0.30 | 0.3% |
| ***Ontario Clean Energy Benefit*** [1] | | | 10% | -$ 9.74 | | | | $ 9.74 | -100.0% |
| **Total Bill on TOU (including OCEB)** | | | | **$ 87.62** | | | **$ 97.66** | $ 10.04 | **11.5%** |

2 **Loss Factor (%)** — 2015 Current: 3.45% — 2016 Proposed: 3.69%

# Table V-VECC-32-4: 2016 Bill Impacts – 800 kWh Consumption

| | | | 2015 Current Board-Approved | | | 2016 TEST YEAR 1 Proposed | | Impact 2016 TEST vs. 2015 Bridge | |
|---|---|---|---|---|---|---|---|---|---|
| | Charge Unit | Volume | Rate ($) | Charge ($) | | Rate ($) | Charge ($) | $ Change | % Change |
| Monthly Service Charge | Monthly | 1 | $ 12.67 | $ 12.67 | | $ 15.98 | $ 15.98 | $ 3.31 | 26.1% |
| Smart Meter Rate Adder | Monthly | 1 | $ - | $ - | | $ - | $ - | $ - | |
| Recovery of CGAAP/CWIP Differential | Monthly | 1 | $ 0.20 | $ 0.20 | | $ 0.20 | $ 0.20 | $ - | 0.0% |
| ICM Rate Rider (2014) | Monthly | 1 | $ 0.07 | $ 0.07 | | $ - | $ - | $ (0.07) | -100.0% |
| | | 1 | $ - | $ - | | $ - | $ - | $ - | |
| | | 1 | $ - | $ - | | $ - | $ - | $ - | |
| Distribution Volumetric Rate | per kWh | 800 | $ 0.0140 | $ 11.20 | | $ 0.0143 | $ 11.41 | $ 0.21 | 1.9% |
| Smart Meter Disposition Rider | per kWh | 800 | $ - | $ - | | $ - | $ - | $ - | |
| LRAM & SSM Rate Rider | per kWh | 800 | $ - | $ - | | $ - | $ - | $ - | |
| ICM Rate Rider (2014) | per kWh | 800 | $ 0.0001 | $ 0.08 | | $ - | $ - | $ (0.08) | -100.0% |
| Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) | per kWh | 800 | $ 0.0001 | $ 0.08 | | $ - | $ - | $ (0.08) | -100.0% |
| Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2016) | per kWh | 800 | $ - | $ - | | -$ 0.0001 | $ (0.08) | $ (0.08) | |
| Recovery of Stranded Meter Assets (2016) | per kWh | 800 | $ - | $ - | | $ 0.0001 | $ 0.08 | $ 0.08 | |
| Account 1575 | per kWh | 800 | $ - | $ - | | -$ 0.0005 | $ (0.40) | $ (0.40) | |
| | | 800 | $ - | $ - | | $ - | $ - | $ - | |
| | | 800 | $ - | $ - | | $ - | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 24.30 | | | $ 27.19 | $ 2.89 | 11.9% |
| Deferral/Variance Account Disposition Rate Rider (2014) | per kWh | 800 | -$ 0.0006 | $ (0.48) | | $ - | $ - | $ 0.48 | -100.0% |
| Disposition of Deferral/Variance Accounts (2016) | per kWh | 800 | $ - | $ - | | $ 0.0002 | $ 0.16 | $ 0.16 | |
| | | 800 | $ - | $ - | | $ - | $ - | $ - | |
| | | 800 | $ - | $ - | | $ - | $ - | $ - | |
| Low Voltage Service Charge | per kWh | 800 | $ 0.0003 | $ 0.24 | | $ 0.0005 | $ 0.40 | $ 0.16 | 66.7% |
| Line Losses on Cost of Power | | 27.60 | $ 0.1021 | $ 2.82 | 29.52 | $ 0.1021 | $ 3.02 | $ 0.20 | 7.0% |
| Smart Meter Entity Charge | Monthly | 1 | $ 0.79 | $ 0.79 | | $ 0.79 | $ 0.79 | $ - | |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 27.67** | | | **$ 31.56** | $ 3.89 | **14.1%** |
| RTSR - Network | per kWh | 828 | $ 0.0080 | $ 6.62 | 830 | $ 0.0080 | $ 6.64 | $ 0.02 | 0.2% |
| RTSR - Line and Transformation Connection | per kWh | 828 | $ 0.0035 | $ 2.90 | 830 | $ 0.0037 | $ 3.07 | $ 0.17 | 6.0% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 37.19** | | | **$ 41.26** | $ 4.08 | **11.0%** |
| Wholesale Market Service Charge (WMSC) | per kWh | 828 | $ 0.0044 | $ 3.64 | 830 | $ 0.0044 | $ 3.65 | $ 0.01 | 0.2% |
| Rural and Remote Rate Protection (RRRP) | per kWh | 828 | $ 0.0013 | $ 1.08 | 830 | $ 0.0013 | $ 1.08 | $ 0.00 | 0.2% |
| Standard Supply Service Charge | Monthly | 1 | $ 0.25 | $ 0.25 | | $ 0.2500 | $ 0.25 | $ - | 0.0% |
| Debt Retirement Charge (DRC) | per kWh | 800 | $ 0.0070 | $ 5.60 | | | $ - | $ (5.60) | -100.0% |
| TOU - Off Peak | per kWh | 512 | $ 0.0800 | $ 40.96 | | $ 0.0800 | $ 40.96 | $ - | 0.0% |
| TOU - Mid Peak | per kWh | 144 | $ 0.1220 | $ 17.57 | | $ 0.1220 | $ 17.57 | $ - | 0.0% |
| TOU - On Peak | per kWh | 144 | $ 0.1610 | $ 23.18 | | $ 0.1610 | $ 23.18 | $ - | 0.0% |
| | | | | | | | | | |
| **Total Bill on TOU (before Taxes)** | | | | **$ 129.47** | | | **$ 127.95** | $ (1.51) | **-1.2%** |
| HST | | | 13% | $ 16.83 | | 13% | $ 16.63 | $ (0.20) | -1.2% |
| **Total Bill** (including HST) | | | | $ 146.30 | | | $ 144.59 | $ (1.71) | -1.2% |
| ***Ontario Clean Energy Benefit*** [1] | | | 10% | -$ 14.63 | | | | $ 14.63 | -100.0% |
| **Total Bill on TOU (including OCEB)** | | | | **$ 131.67** | | | **$ 144.59** | $ 12.92 | **9.8%** |

| | 2015 | 2016 |
|---|---|---|
| **Loss Factor (%)** | 3.45% | 3.69% |

# Table V-VECC-32-5: 2016 Bill Impacts – 1000 kWh Consumption

| | | | 2015 Current Board-Approved | | | 2016 TEST YEAR 1 Proposed | | Impact 2016 TEST vs. 2015 Bridge | |
|---|---|---|---|---|---|---|---|---|---|
| | Charge Unit | Volume | Rate ($) | Charge ($) | | Rate ($) | Charge ($) | $ Change | % Change |
| Monthly Service Charge | Monthly | 1 | $ 12.67 | $ 12.67 | | $ 15.98 | $ 15.98 | $ 3.31 | 26.1% |
| Smart Meter Rate Adder | Monthly | 1 | $ - | $ - | | $ - | $ - | $ - | |
| Recovery of CGAAP/CWIP Differential | Monthly | 1 | $ 0.20 | $ 0.20 | | $ 0.20 | $ 0.20 | $ - | 0.0% |
| ICM Rate Rider (2014) | Monthly | 1 | $ 0.07 | $ 0.07 | | $ - | $ - | $ (0.07) | -100.0% |
| | | 1 | $ - | $ - | | $ - | $ - | $ - | |
| | | 1 | $ - | $ - | | $ - | $ - | $ - | |
| Distribution Volumetric Rate | per kWh | 1000 | $ 0.0140 | $ 14.00 | | $ 0.0143 | $ 14.27 | $ 0.27 | 1.9% |
| Smart Meter Disposition Rider | per kWh | 1000 | $ - | $ - | | $ - | $ - | $ - | |
| LRAM & SSM Rate Rider | per kWh | 1000 | $ - | $ - | | $ - | $ - | $ - | |
| ICM Rate Rider (2014) | per kWh | 1000 | $ 0.0001 | $ 0.10 | | $ - | $ - | $ (0.10) | -100.0% |
| Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) | per kWh | 1000 | $ 0.0001 | $ 0.10 | | $ - | $ - | $ (0.10) | -100.0% |
| Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2016) | per kWh | 1000 | $ - | $ - | | -$ 0.0001 | $ (0.10) | $ (0.10) | |
| Recovery of Stranded Meter Assets (2016) | per kWh | 1000 | $ - | $ - | | $ 0.0001 | $ 0.10 | $ 0.10 | |
| Account 1575 | per kWh | 1000 | $ - | $ - | | -$ 0.0005 | $ (0.50) | $ (0.50) | |
| | | 1000 | $ - | $ - | | $ - | $ - | $ - | |
| | | 1000 | $ - | $ - | | $ - | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 27.14 | | | $ 29.95 | $ 2.81 | 10.3% |
| Deferral/Variance Account Disposition Rate Rider (2014) | per kWh | 1000 | -$ 0.0006 | $ (0.60) | | $ - | $ - | $ 0.60 | -100.0% |
| Disposition of Deferral/Variance Accounts (2016) | per kWh | 1000 | $ - | $ - | | $ 0.0002 | $ 0.20 | $ 0.20 | |
| | | 1000 | $ - | $ - | | $ - | $ - | $ - | |
| | | 1000 | $ - | $ - | | $ - | $ - | $ - | |
| Low Voltage Service Charge | per kWh | 1000 | $ 0.0003 | $ 0.30 | | $ 0.0005 | $ 0.50 | $ 0.20 | 66.7% |
| Line Losses on Cost of Power | | 34.50 | $ 0.1021 | $ 3.52 | 36.90 | $ 0.1021 | $ 3.77 | $ 0.25 | 7.0% |
| Smart Meter Entity Charge | Monthly | 1 | $ 0.7900 | $ 0.79 | | $ 0.7900 | $ 0.79 | $ - | |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 31.15** | | | **$ 35.20** | $ 4.05 | **13.0%** |
| RTSR - Network | per kWh | 1035 | $ 0.0080 | $ 8.28 | 1037 | $ 0.0080 | $ 8.30 | $ 0.02 | 0.2% |
| RTSR - Line and Transformation Connection | per kWh | 1035 | $ 0.0035 | $ 3.62 | 1037 | $ 0.0037 | $ 3.84 | $ 0.22 | 6.0% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 43.05** | | | **$ 47.34** | $ 4.29 | **10.0%** |
| Wholesale Market Service Charge (WMSC) | per kWh | 1035 | $ 0.0044 | $ 4.55 | 1037 | $ 0.0044 | $ 4.56 | $ 0.01 | 0.2% |
| Rural and Remote Rate Protection (RRRP) | per kWh | 1035 | $ 0.0013 | $ 1.34 | 1037 | $ 0.0013 | $ 1.35 | $ 0.00 | 0.2% |
| Standard Supply Service Charge | Monthly | 1 | $ 0.25 | $ 0.25 | | $ 0.2500 | $ 0.25 | $ - | 0.0% |
| Debt Retirement Charge (DRC) | per kWh | 1000 | $ 0.0070 | $ 7.00 | | | $ - | $ (7.00) | -100.0% |
| TOU - Off Peak | per kWh | 640 | $ 0.0800 | $ 51.20 | | $ 0.0800 | $ 51.20 | $ - | 0.0% |
| TOU - Mid Peak | per kWh | 180 | $ 0.1220 | $ 21.96 | | $ 0.1220 | $ 21.96 | $ - | 0.0% |
| TOU - On Peak | per kWh | 180 | $ 0.1610 | $ 28.98 | | $ 0.1610 | $ 28.98 | $ - | 0.0% |
| | | | | | | | | | |
| **Total Bill on TOU (before Taxes)** | | | | **$ 158.34** | | | **$ 155.64** | $ (2.70) | **-1.7%** |
| HST | | | 13% | $ 20.58 | | 13% | $ 20.23 | $ (0.35) | -1.7% |
| **Total Bill** (including HST) | | | | $ 178.92 | | | $ 175.87 | $ (3.05) | -1.7% |
| ***Ontario Clean Energy Benefit*** [1] | | | 10% | -$ 17.89 | | | | $ 17.89 | -100.0% |
| **Total Bill on TOU (including OCEB)** | | | | **$ 161.03** | | | **$ 175.87** | $ 14.84 | **9.2%** |
| | | | | | | | | | |

| | | |
|---|---|---|
| **Loss Factor (%)** | 3.45% | 3.69% |

# Table V-VECC-32-6: 2016 Bill Impacts – 1500 kWh Consumption

| | Charge Unit | Volume | 2015 Current Board-Approved Rate ($) | 2015 Current Board-Approved Charge ($) | 2016 Volume | 2016 TEST YEAR 1 Proposed Rate ($) | 2016 TEST YEAR 1 Proposed Charge ($) | Impact 2016 TEST vs. 2015 Bridge $ Change | Impact 2016 TEST vs. 2015 Bridge % Change |
|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | Monthly | 1 | $ 12.67 | $ 12.67 | | $ 15.98 | $ 15.98 | $ 3.31 | 26.1% |
| Smart Meter Rate Adder | Monthly | 1 | $ - | $ - | | $ - | $ - | $ - | |
| Recovery of CGAAP/CWIP Differential | Monthly | 1 | $ 0.20 | $ 0.20 | | $ 0.20 | $ 0.20 | $ - | 0.0% |
| ICM Rate Rider (2014) | Monthly | 1 | $ 0.07 | $ 0.07 | | $ - | $ - | $ (0.07) | -100.0% |
| | | 1 | $ - | $ - | | $ - | $ - | $ - | |
| | | 1 | $ - | $ - | | $ - | $ - | $ - | |
| Distribution Volumetric Rate | per kWh | 1500 | $ 0.0140 | $ 21.00 | | $ 0.0143 | $ 21.40 | $ 0.40 | 1.9% |
| Smart Meter Disposition Rider | per kWh | 1500 | $ - | $ - | | $ - | $ - | $ - | |
| LRAM & SSM Rate Rider | per kWh | 1500 | $ - | $ - | | $ - | $ - | $ - | |
| ICM Rate Rider (2014) | per kWh | 1500 | $ 0.0001 | $ 0.15 | | $ - | $ - | $ (0.15) | -100.0% |
| Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) | per kWh | 1500 | $ 0.0001 | $ 0.15 | | $ - | $ - | $ (0.15) | -100.0% |
| Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2016) | per kWh | 1500 | $ - | $ - | | -$ 0.0001 | $ (0.15) | $ (0.15) | |
| Recovery of Stranded Meter Assets (2016) | per kWh | 1500 | $ - | $ - | | $ 0.0001 | $ 0.15 | $ 0.15 | |
| Account 1575 | per kWh | 1500 | $ - | $ - | | -$ 0.0005 | $ (0.75) | $ (0.75) | |
| | | 1500 | $ - | $ - | | $ - | $ - | $ - | |
| | | 1500 | $ - | $ - | | $ - | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 34.24 | | | $ 36.83 | $ 2.59 | 7.6% |
| Deferral/Variance Account Disposition Rate Rider (2014) | per kWh | 1500 | -$ 0.0006 | $ (0.90) | | $ - | $ - | $ 0.90 | -100.0% |
| Disposition of Deferral/Variance Accounts (2016) | per kWh | 1500 | $ - | $ - | | $ 0.0002 | $ 0.30 | $ 0.30 | |
| | | 1500 | $ - | $ - | | $ - | $ - | $ - | |
| | | 1500 | $ - | $ - | | $ - | $ - | $ - | |
| Low Voltage Service Charge | per kWh | 1500 | $ 0.0003 | $ 0.45 | | $ 0.0005 | $ 0.75 | $ 0.30 | 66.7% |
| Line Losses on Cost of Power | | 51.75 | $ 0.1021 | $ 5.29 | 55.35 | $ 0.1021 | $ 5.65 | $ 0.37 | 7.0% |
| Smart Meter Entity Charge | Monthly | 1 | $ 0.7900 | $ 0.79 | | $ 0.7900 | $ 0.79 | $ - | |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 39.87** | | | **$ 44.32** | $ 4.46 | **11.2%** |
| RTSR - Network | per kWh | 1552 | $ 0.0080 | $ 12.41 | 1555 | $ 0.0080 | $ 12.44 | $ 0.03 | 0.2% |
| RTSR - Line and Transformation Connection | per kWh | 1552 | $ 0.0035 | $ 5.43 | 1555 | $ 0.0037 | $ 5.75 | $ 0.32 | 6.0% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 57.71** | | | **$ 62.52** | $ 4.81 | **8.3%** |
| Wholesale Market Service Charge (WMSC) | per kWh | 1552 | $ 0.0044 | $ 6.83 | 1555 | $ 0.0044 | $ 6.84 | $ 0.02 | 0.2% |
| Rural and Remote Rate Protection (RRRP) | per kWh | 1552 | $ 0.0013 | $ 2.02 | 1555 | $ 0.0013 | $ 2.02 | $ 0.00 | 0.2% |
| Standard Supply Service Charge | Monthly | 1 | $ 0.25 | $ 0.25 | | $ 0.2500 | $ 0.25 | $ - | 0.0% |
| Debt Retirement Charge (DRC) | per kWh | 1500 | $ 0.0070 | $ 10.50 | | | $ - | $ (10.50) | -100.0% |
| TOU - Off Peak | per kWh | 960 | $ 0.0800 | $ 76.80 | | $ 0.0800 | $ 76.80 | $ - | 0.0% |
| TOU - Mid Peak | per kWh | 270 | $ 0.1220 | $ 32.94 | | $ 0.1220 | $ 32.94 | $ - | 0.0% |
| TOU - On Peak | per kWh | 270 | $ 0.1610 | $ 43.47 | | $ 0.1610 | $ 43.47 | $ - | 0.0% |
| **Total Bill on TOU (before Taxes)** | | | | **$ 230.52** | | | **$ 224.85** | $ (5.67) | **-2.5%** |
| HST | | | 13% | $ 29.97 | | 13% | $ 29.23 | $ (0.74) | -2.5% |
| **Total Bill** (including HST) | | | | $ 260.48 | | | $ 254.08 | $ (6.41) | -2.5% |
| ***Ontario Clean Energy Benefit*** [1] | | | 10% | -$ 26.05 | | | | $ 26.05 | -100.0% |
| **Total Bill on TOU (including OCEB)** | | | | **$ 234.43** | | | **$ 254.08** | $ 19.64 | **8.4%** |

| | | |
|---|---|---|
| **Loss Factor (%)** | 3.45% | 3.69% |

## Table V-VECC-32-7: 2016 Bill Impacts – 2000 kWh Consumption

| | | | 2015 Current Board-Approved | | | 2016 TEST YEAR 1 Proposed | | Impact 2016 TEST vs. 2015 Bridge | |
|---|---|---|---|---|---|---|---|---|---|
| | Charge Unit | Volume | Rate ($) | Charge ($) | | Rate ($) | Charge ($) | $ Change | % Change |
| Monthly Service Charge | Monthly | 1 | $ 12.67 | $ 12.67 | | $ 15.98 | $ 15.98 | $ 3.31 | 26.1% |
| Smart Meter Rate Adder | Monthly | 1 | $ - | $ - | | $ - | $ - | $ - | |
| Recovery of CGAAP/CWIP Differential | Monthly | 1 | $ 0.20 | $ 0.20 | | $ 0.20 | $ 0.20 | $ - | 0.0% |
| ICM Rate Rider (2014) | Monthly | 1 | $ 0.07 | $ 0.07 | | $ - | $ - | $ (0.07) | -100.0% |
| | | 1 | $ - | $ - | | $ - | $ - | $ - | |
| | | 1 | $ - | $ - | | $ - | $ - | $ - | |
| Distribution Volumetric Rate | per kWh | 2000 | $ 0.0140 | $ 28.00 | | $ 0.0143 | $ 28.54 | $ 0.54 | 1.9% |
| Smart Meter Disposition Rider | per kWh | 2000 | $ - | $ - | | $ - | $ - | $ - | |
| LRAM & SSM Rate Rider | per kWh | 2000 | $ - | $ - | | $ - | $ - | $ - | |
| ICM Rate Rider (2014) | per kWh | 2000 | $ 0.0001 | $ 0.20 | | $ - | $ - | $ (0.20) | -100.0% |
| Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) | per kWh | 2000 | $ 0.0001 | $ 0.20 | | $ - | $ - | $ (0.20) | -100.0% |
| Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2016) | per kWh | 2000 | $ - | $ - | | -$ 0.0001 | $ (0.20) | $ (0.20) | |
| Recovery of Stranded Meter Assets (2016) | per kWh | 2000 | $ - | $ - | | $ 0.0001 | $ 0.20 | $ 0.20 | |
| Account 1575 | per kWh | 2000 | $ - | $ - | | -$ 0.0005 | $ (1.00) | $ (1.00) | |
| | | 2000 | $ - | $ - | | $ - | $ - | $ - | |
| | | 2000 | $ - | $ - | | $ - | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 41.34 | | | $ 43.71 | $ 2.37 | 5.7% |
| Deferral/Variance Account Disposition Rate Rider (2014) | per kWh | 2000 | -$ 0.0006 | $ (1.20) | | $ - | $ - | $ 1.20 | -100.0% |
| Disposition of Deferral/Variance Accounts (2016) | per kWh | 2000 | $ - | $ - | | $ 0.0002 | $ 0.40 | $ 0.40 | |
| | | 2000 | $ - | $ - | | $ - | $ - | $ - | |
| | | 2000 | $ - | $ - | | $ - | $ - | $ - | |
| Low Voltage Service Charge | per kWh | 2000 | $ 0.0003 | $ 0.60 | | $ 0.0005 | $ 1.00 | $ 0.40 | 66.7% |
| Line Losses on Cost of Power | | 69.00 | $ 0.1021 | $ 7.05 | 73.80 | $ 0.1021 | $ 7.54 | $ 0.49 | 7.0% |
| Smart Meter Entity Charge | Monthly | 1 | $ 0.7900 | $ 0.79 | | $ 0.7900 | $ 0.79 | $ - | |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 48.58** | | | **$ 53.44** | $ 4.86 | **10.0%** |
| RTSR - Network | per kWh | 2069 | $ 0.0080 | $ 16.55 | 2074 | $ 0.0080 | $ 16.59 | $ 0.04 | 0.2% |
| RTSR - Line and Transformation Connection | per kWh | 2069 | $ 0.0035 | $ 7.24 | 2074 | $ 0.0037 | $ 7.67 | $ 0.43 | 6.0% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 72.37** | | | **$ 77.71** | $ 5.33 | **7.4%** |
| Wholesale Market Service Charge (WMSC) | per kWh | 2069 | $ 0.0044 | $ 9.10 | 2074 | $ 0.0044 | $ 9.12 | $ 0.02 | 0.2% |
| Rural and Remote Rate Protection (RRRP) | per kWh | 2069 | $ 0.0013 | $ 2.69 | 2074 | $ 0.0013 | $ 2.70 | $ 0.01 | 0.2% |
| Standard Supply Service Charge | Monthly | 1 | $ 0.25 | $ 0.25 | | $ 0.2500 | $ 0.25 | $ - | 0.0% |
| Debt Retirement Charge (DRC) | per kWh | 2000 | $ 0.0070 | $ 14.00 | | | $ - | $ (14.00) | -100.0% |
| TOU - Off Peak | per kWh | 1280 | $ 0.0800 | $ 102.40 | | $ 0.0800 | $ 102.40 | $ - | 0.0% |
| TOU - Mid Peak | per kWh | 360 | $ 0.1220 | $ 43.92 | | $ 0.1220 | $ 43.92 | $ - | 0.0% |
| TOU - On Peak | per kWh | 360 | $ 0.1610 | $ 57.96 | | $ 0.1610 | $ 57.96 | $ - | 0.0% |
| | | | | | | | | | |
| **Total Bill on TOU (before Taxes)** | | | | **$ 302.69** | | | **$ 294.06** | $ (8.64) | **-2.9%** |
| HST | | | 13% | $ 39.35 | | 13% | $ 38.23 | $ (1.12) | -2.9% |
| **Total Bill** (including HST) | | | | $ 342.04 | | | $ 332.28 | $ (9.76) | -2.9% |
| ***Ontario Clean Energy Benefit*** [1] | | | 10% | -$ 34.20 | | | | $ 34.20 | -100.0% |
| **Total Bill on TOU (including OCEB)** | | | | **$ 307.84** | | | **$ 332.28** | $ 24.44 | **7.9%** |

e) Please see table below for the number of Residential customers fall into each of the specified average monthly use categories:

| Average Monthly Use | Number of Customers |
|---|---|
| 0-100 kWh | 1,764 |
| >100-250 kWh | 14,595 |
| >250-500 kWh | 84,125 |
| >500-800 kWh | 107,236 |
| >800-1,000 kWh | 38,162 |
| >1,000 - 1,500 kWh | 34,871 |
| >1,500-2,000 kWh | 8,311 |
| >2,000 kWh | 5,733 |

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## Section VI

**VI-Staff-96**

**Ref: T7/S1/p. 2**

At the above reference, PowerStream's Conditions of Service are discussed.

a) Please identify any rates and charges that are included in the Applicant's Conditions of Service, but do not appear on the Board-approved tariff sheet, and provide an explanation for the nature of the costs being recovered through these rates and charges.

b) Please provide a schedule outlining the revenues recovered from these rates and charges from 2012 to 2014 inclusive, and the revenues forecasted for the 2015 bridge and 2016 test years.

c) Please explain whether, in the Applicant's view, these rates and charges should be included on the Applicant's tariff sheet of approved rates and charges.

**RESPONSE:**

a) PowerStream confirms that there are no explicit rates or charges mentioned in the Conditions of Service that do not appear on the Board-approved tariff sheet (Rate Order).

b) As mentioned in VI-Staff-96(a) above, PowerStream does not have explicit rates or charges mentioned in its Conditions of Service document, and as such, the requested revenue recovery schedule cannot be provided.

c) As mentioned in VI-Staff-96(a) above, PowerStream does not have explicit rates or charges mentioned in its Conditions of Service document, and as such, this is not applicable.

**VI-Staff-97**

**Ref: T25/S1/p. 1**

Upon completing all interrogatories from OEB staff and intervenors, please provide an updated RRWF in working Microsoft Excel format with any corrections or adjustments that the Applicant wishes to make to the amounts in the populated version of the RRWF filed in the initial applications. Entries for changes and adjustments should be included in the middle column on sheet 3 Data_Input_Sheet. Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or an explanatory note. Such notes should be documented on Sheet 10 Tracking Sheet, and may also be included on other sheets in the RRWF to assist understanding of changes.

**RESPONSE:**

Please see Section A, Application Update Summary, for the changes adopted as a result of these interrogatories. The updated RRWFs are presented in Section A, Tab 2, Schedule 1.

**VI-Staff-98**

**Ref: T26/S1/p.2**

At the above reference PowerStream discusses its proposals in the application for annual adjustments, adjustments outside the normal course of business and termination of the rate plan.

PowerStream states that it:

> …proposes to file a draft rate order containing evidence supporting the changes from the original revenue requirement and interim rates approved in this Application. PowerStream believes that the time and resources required would be similar to an IRM application of average or medium complexity.

a) Please confirm that in the Application PowerStream is proposing final rates for 2016 and interim rates for the 2017 to 2020 years of the Application. If not, please explain.

b) Assuming part a is confirmed, please state why PowerStream is proposing interim rates for the 2017 to 2020 period and whether there are any precedents for setting rates interim for a four year period.

c) Please discuss the request for interim rates in the context of the RRFE expectation that "a distributor's application under Custom IR to demonstrate its ability to manage within the rates set, given the actual costs and revenues will vary from forecast." (RRFE report, p.19).

**RESPONSE:**

a) PowerStream confirms that it is requesting final rates for 2016 and interim rates for the 2017 to 2020 years.

b) PowerStream's proposal is to set the revenue requirement for each year of the Custom IR plan (2016 through 2020). Subsequent years would start with the revenue requirement approved by the Board in this proceeding and would be subject to the annual adjustments accepted by the Board in this proceeding. It is in this context that PowerStream has asked that the rates for 2017 to 2020 be labelled and approved as interim rates. The Rate Order flowing from this proceeding may not need to include the rates beyond the first year, as the Board has done in the case of Horizon Utilities' Custom IR proceeding.

c) There are items that are difficult to forecast accurately over a five year term and that could have significant impacts on the revenue requirement to be collected through rates. This would include the cost of power, inflation, taxes, interest rates/cost of capital, changes in third party costs passed through to customers and accumulation of deferral and variance account balances. The annual adjustments proposed are needed to support the Board's RRFE policy as stated on page 4 of the RRFE report:

*"The first two objectives, the protection of consumer interests and the promotion of economic efficiency and cost effectiveness within a financially viable industry, are the foundation of the renewed regulatory framework."*