# PowerStream Inc.

# EB-2015-0003

# Panel 2

# OEB Staff Compendium

# November 23, 2015

## 5.4.3 SYSTEM CAPABILITY ASSESSMENT FOR RENEWABLE ENERGY GENERATION

*This section provides information on the capability of a distributor's distribution system to accommodate REG, including a summary of the distributor's load and renewable energy generation connection forecast by feeder/substation (where applicable); and information identifying specific network locations where constraints are expected to emerge due to forecast changes in load and/or connected renewable generation capacity.*

*In relation to renewable or other distributed energy generation connections, the information that must be considered by a distributor and documented in an application (where applicable) includes:*

*a) applications from renewable generators over 10kW for connection in the distributor's service area;*

*b) the number and the capacity (in MW) of renewable generation connections anticipated over the forecast period based on existing connection applications, information available from the IESO and any other information the distributor has about the potential for renewable generation in its service area (where a distributor has a large service area, or two or more non-contiguous regions included in its service area, a regional breakdown should be provided);*

*c) the capacity (MW) of the distributor's distribution system to connect renewable energy generation located within the distributor's service area;*

*d) constraints related to the connection of renewable generation, either within the distributor's system or upstream system (host distributor and/or transmitter); and*

*e) constraints for an embedded distributor that may result from the connections*

### Applications from Renewable Generators over 10kW

As of August 1st 2014, PowerStream has connected eighty four Feed-In Tariff (FIT) applications for a total of 16,016 kW of generation (item F3 from Table 1). In addition, there are 203 projects, totaling 36,448 kW (item F4 from Table 1), that have been approved by PowerStream for connection and are currently being constructed. PowerStream's FIT breakdown is seen in Table 1.

| Item | Process Description | Project Count | Capacity (kW) |
|---|---|---|---|
| F1 | Total FIT applications *received* by IESO | 314 | 56,326 |
| F2 | Total FIT applications *approved* by IESO | 204 | 36,583 |
| F3 | Total FIT applications *approved* by PowerStream | 203 | 36,448 |
| F4 | Total FIT projects *connected* by PowerStream | 84 | 16,016 |

Table 1: FIT Projects

The 203 connected, or about to be connected FIT generators, are dispersed throughout PowerStream's territory. Projects are located predominately in Markham, Richmond Hill, Barrie and Vaughan however, there are also scattered projects located in the smaller communities of Aurora, Alliston, and Bradford. Table 2 details the FIT Generators by geographic region (as of Aug.1 2014):

| | | FIT | |
|---|---|---|---|
| | | Projects | Generation (kW) |
| Northern Region | Alliston | 2 | 135 |
| | Barrie | 23 | 2,892 |
| | Beeton | | |
| | Bradford | 4 | 590 |
| | Penetang | 2 | 325 |
| | Thornton | | |
| | Tottenham | 2 | 350 |
| | Northern Sub Total | 33 | 4,292 |
| Southern Region | Aurora | 6 | 831.8 |
| | Markham | 59 | 9,353 |
| | Richmond Hill | 17 | 3,743 |
| | Vaughan | 88 | 18,229 |
| | Southern Sub Total | 170 | 32,156 |
| **Total Projects** | | **203** | **36,448** |

Table 2: FIT Generators by Geographic Region

**Number and Capacity (MW) of Renewable Connections Anticipated**

Planned Development

PowerStream has projected Renewable Generation growth for 2015-2020 based on existing FIT data and industry expectations.

Renewable Generation growth for 2015-2020 has been estimated based on PowerStream's existing FIT/MicroFIT data from 2009-2014 and the expected evolution of the IESO's FIT program.

As of August 1st 2014, PowerStream customer FIT and microFIT submissions to the IESO have totaled 3,031 applications, grossing over 76MW of potential generation. The 2012-2014 application data, illustrated in Figure 1, indicates a strong average monthly growth rate to date.

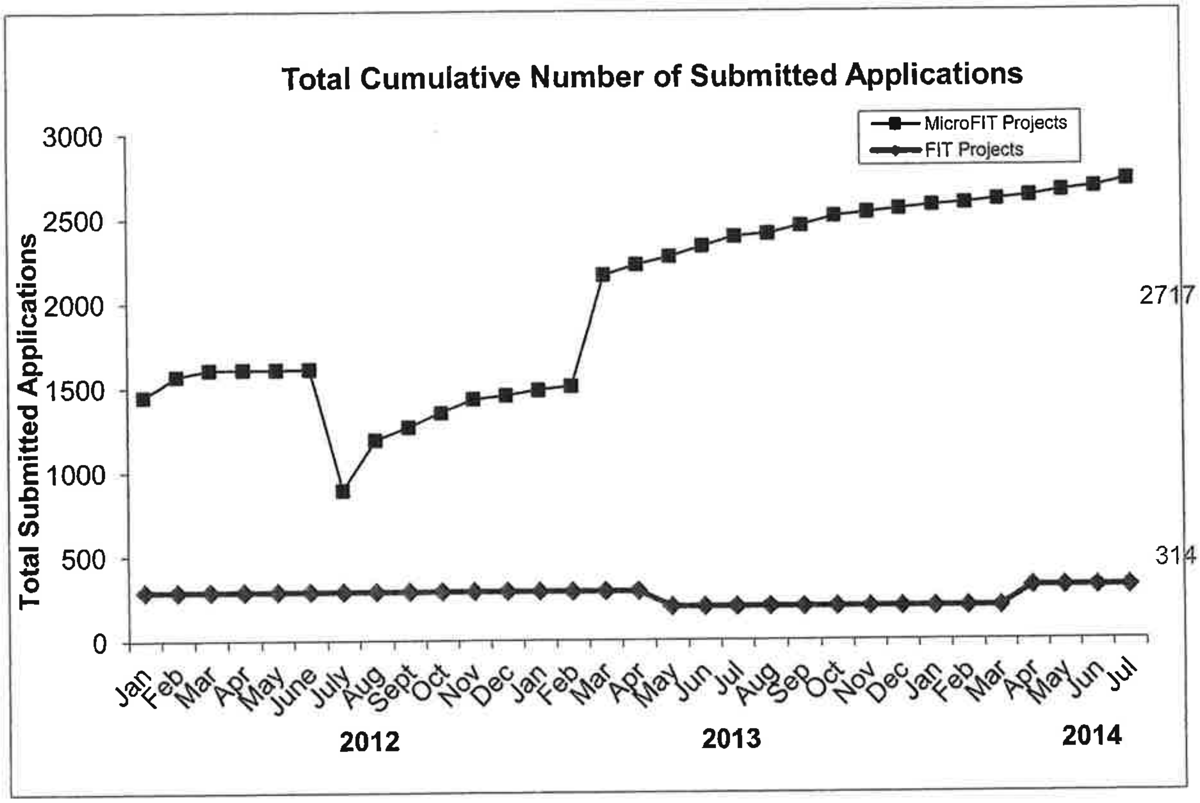



Figure 1: Cumulative Submitted Application by Month

Source: IESO LDC Portal

Although Renewable Generation installations in PowerStream's service area have been increasing, they are mainly focused on roof top solar applications. Renewable Generation by source is broken down as shown in Table 3:

| Fuel Type | FIT | MicroFIT |
|---|---|---|
| Solar photovoltaic - Roof Top | 314 | 2,717 |

Table 3: Fit/MicroFIT Volumes

The project size distribution is seen in Figure 2, which illustrates limited interest in projects over 250kW and no interest in projects greater than 500kW.

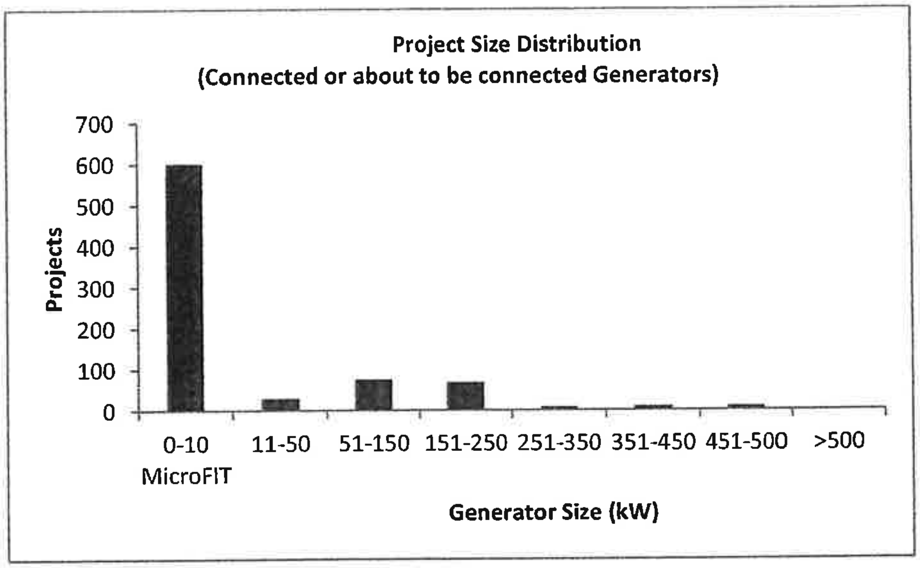



Figure 2: Project Size Distribution

PowerStream's regions are predominantly made up of urban areas which are ideal for roof top solar, but less attractive for larger ground mount solar or wind installations. Therefore, because there is limited potential for major wind or other ground mount projects, and economically viable roof tops are finite, installations are expected to slow down over the next six years. This assumes that FIT program pricing continues to provide less than ten year payback for commercial rooftop installations.

Program Progression

In order to create a six year projection of FIT growth in PowerStream's distribution area, some assumptions were made regarding the program's future direction.

The IESO's FIT Program has been relatively unchanged since its inception in 2009. Following three years of Renewable Generation experience, valuable insight has been gained into the public demand for green energy and potential capacity constraints caused by the distribution grid. Based on these lessons learned, IESO made adjustments to the FIT program in 2012, considering some of the following potential changes:

- Price Point Drop to reflect the current market per unit costs of retail generation equipment;
- New Funding Model to make smaller FIT projects more financially feasible; and
- Generation Caps to slow the FIT program down to manageable levels but still maintain the current job creation model.

The above items were taken into consideration when developing PowerStream's six year Anticipated Generator Connections model.

Anticipated Generator Connection Applications

Based on PowerStream's 2009-2014 FIT/microFIT data and future assumptions regarding the IESO's FIT program, it is expected that application submissions will remain steady through 2015, begin to decline in 2016, and continue to descend through 2018. Table 4 outlines the expected decline:

| | Applications/year | Cumulative Applications |
|---|---|---|
| 2010 | 666 | 666 |
| 2011 | 1038 | 1704 |
| 2012 | 36 | 1740 |
| 2013 | 1005 | 2745 |
| 2014 | 286 | 3031 |
| 2015 | 215 | 3245 |
| 2016 | 161 | 3467 |
| 2017 | 121 | 3527 |
| 2018 | 60 | 3587 |
| 2019 | 0 | 3587 |
| 2020 | 0 | 3587 |

Table 4: Actual and Projected Application Volumes

The IESO currently has Renewable Generation applications totaling 76MW for PowerStream's service territory. Based on PowerStream's anticipated FIT connection model, projected growth for Renewable Generation in PowerStream's territory will pursue the trend depicted in Figure 3.

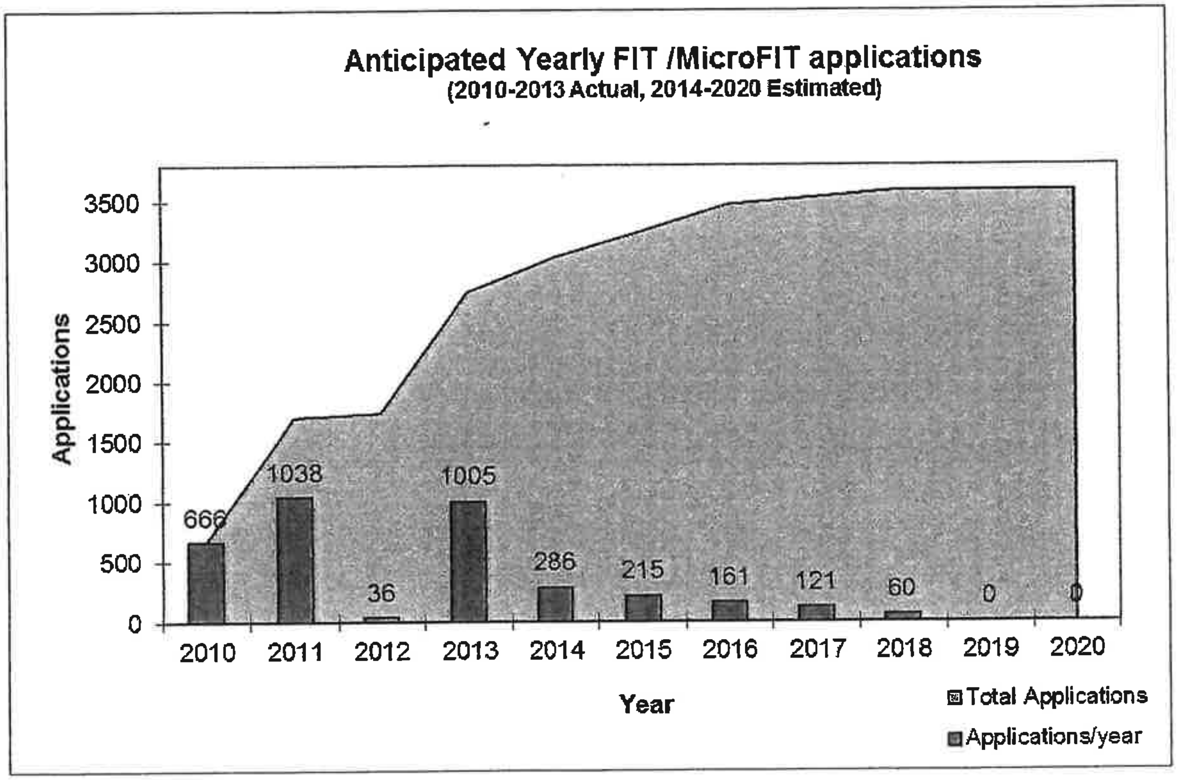



Figure 3: Annual FIT Applications

PowerStream Renewable Generation Growth

Following steady growth through 2014, the Renewable Generation growth rate is expected to peak and begin to decline in 2016 through 2018. PowerStream's Renewable Generation load is expected to reach 107.7MW by 2020. Refer to Figure 4.

**Projected Renewable Generation Cumulative Growth**

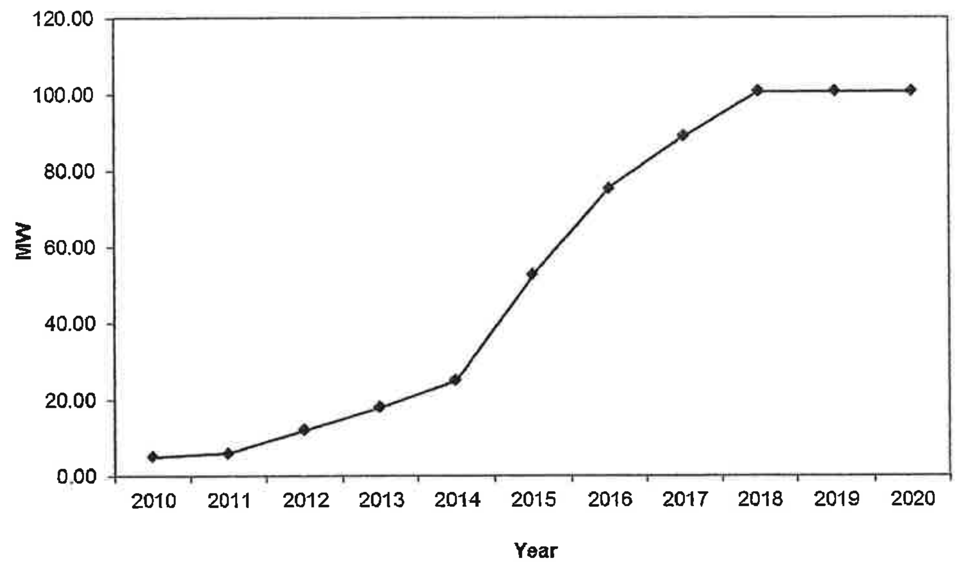



Figure 4: Projected Connected Growth

PowerStream North Renewable Generation Growth

The IESO currently has Renewable Generation applications totaling 11.044MW for PowerStream North. Based on projected growth PowerStream expects this number to reach 16.11 MW by 2018. Figure 5 illustrates Renewable Generation growth in the North between 2009 and 2020.

**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-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.

**JTC 1.12: To try and break out the material and external purchase costs for each of the years 2012 through 2020 for work completed by internal resources, and this is with respect to the answer given to 2-Staff-59.**

**RESPONSE:**

Refer to Table JTC-1.12.

**Table JTC-1.12.**

| Undertaking 1.12<br>Based on IR Staff-59 referring to previous IR SEC-27 | Actual $ 2012 | Actual $ 2013 | Actual $ 2014 | Budget $ 2015 | Budget $ 2016 | Budget $ 2017 | Budget $ 2018 | Budget $ 2019 | Budget $ 2020 |
|---|---|---|---|---|---|---|---|---|---|
| Contract / Consulting / Prof Serv | 46,409,337 | 56,519,306 | 70,507,262 | 57,216,885 | 60,709,568 | 65,721,892 | 64,740,797 | 70,610,138 | 69,022,129 |
| Material, including Burdens | 16,401,266 | 19,641,433 | 21,898,049 | 22,836,704 | 32,223,635 | 31,359,084 | 29,489,255 | 26,277,768 | 28,637,491 |
| External Purchases | 18,386,681 | 10,161,295 | 10,439,174 | 21,296,147 | 19,267,701 | 14,724,179 | 14,688,031 | 12,830,074 | 14,138,506 |
| Total Capital Spend - Net Rate Base | 74,915,000 | 93,500,000 | 109,488,127 | 118,399,999 | 132,800,017 | 131,499,752 | 125,399,834 | 125,400,540 | 125,400,071 |
| Total Capital Spend - Gross Rate Base | 105,841,860 | 114,852,271 | 132,435,515 | 136,722,738 | 154,813,872 | 154,422,481 | 149,232,485 | 149,202,833 | 150,722,676 |
| Capital Contribution | - 30,926,860 | - 21,352,271 | - 22,947,387 | - 18,322,740 | - 22,013,855 | - 22,922,729 | - 23,832,651 | - 23,802,293 | - 25,322,604 |
| | | | | | | | | | |

Note: The above figures for Total Capital Spend (Gross) - Contract/Material/External Purchase cannot be broken down further into Dollars for Management Staff vs Dollars for Non-Management Staff within the time frame required.

**JTC 1.9: To provide the labour and equipment and material costs for the unit costs reflected in the table that is marked as KTC1.1. Also, to do an estimate about what the blended rates would be.**

**RESPONSE:**

a) Refer to Table JTC-1.9a for the breakdown of the asset classes marked as KTC1.1.

**Table JTC-1.9a**

| | | Planned | | | | | |
|---|---|---|---|---|---|---|---|
| **Assets** | **Cost Type** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
| **Automated Switches** | Labour | 126,228 | 129,293 | 132,358 | 135,422 | 138,487 | 141,552 |
| | Material | 247,199 | 254,617 | 262,267 | 270,143 | 278,300 | 286,749 |
| | Vehicle | 33,968 | 33,968 | 33,968 | 33,968 | 33,968 | 33,968 |
| | Admin | 28,518 | 29,251 | 30,002 | 30,767 | 31,553 | 32,359 |
| **Automated Switches Total** | | **435,912** | **447,130** | **458,595** | **470,301** | **482,308** | **494,628** |
| **Distribution Transformer** | Labour | 84,480 | 86,520 | 88,560 | 90,600 | 92,640 | 94,680 |
| | Contract | 93,500 | 96,305 | 99,194 | 102,169 | 105,234 | 108,391 |
| | Material | 264,000 | 271,920 | 280,078 | 288,479 | 297,133 | 306,046 |
| | Vehicle | 19,800 | 19,800 | 19,800 | 19,800 | 19,800 | 19,800 |
| | Admin | 32,325 | 33,218 | 34,134 | 35,073 | 36,036 | 37,024 |
| **Distribution Transformer Total** | | **494,105** | **507,763** | **521,766** | **536,122** | **550,844** | **565,941** |
| **Mini Rupter Switches** | Labour | 183,140 | 187,600 | 192,060 | 196,520 | 200,980 | 205,440 |
| | Contract | 40,000 | 41,200 | 42,436 | 43,709 | 45,020 | 46,371 |
| | Material | 264,000 | 271,920 | 280,078 | 288,479 | 297,134 | 306,049 |
| | Vehicle | 52,800 | 52,800 | 52,800 | 52,800 | 52,800 | 52,800 |
| | Admin | 37,796 | 38,747 | 39,716 | 40,706 | 41,715 | 42,746 |
| **Mini Rupter Switches Total** | | **577,736** | **592,267** | **607,090** | **622,214** | **637,649** | **653,406** |
| **Switchgear Replacement Program** | Labour | 142,989 | 165,318 | 174,006 | 178,024 | 182,042 | 186,060 |
| | Contract | 341,642 | 397,289 | 420,700 | 433,321 | 446,321 | 459,711 |
| | Material | 1,351,925 | 1,572,127 | 1,664,770 | 1,714,713 | 1,766,155 | 1,819,139 |
| | Vehicle | 35,823 | 40,410 | 41,580 | 41,580 | 41,580 | 41,580 |
| | Admin | 131,067 | 152,260 | 161,074 | 165,735 | 170,527 | 175,454 |
| **Switchgear Replacement Program Total** | | **2,003,445** | **2,327,404** | **2,462,129** | **2,533,373** | **2,606,624** | **2,681,945** |
| **Transformer and Municipal Station Circuit Breaker** | Labour | 100,972 | 146,339 | 152,179 | 134,644 | 141,068 | 107,650 |
| | Contract | 329,088 | 632,957 | 630,945 | 1,293,929 | 1,131,800 | 491,531 |
| | Purchases | 688,606 | 1,265,190 | 1,252,414 | 987,758 | 944,242 | 655,065 |
| | Vehicle | 20,768 | 33,264 | 35,376 | 28,858 | 29,062 | 23,619 |
| | Admin | 79,760 | 145,443 | 144,964 | 171,163 | 157,232 | 89,451 |
| **Transformer and Municipal Station Circuit Breaker Total** | | **1,219,194** | **2,223,193** | **2,215,878** | **2,616,351** | **2,403,405** | **1,367,316** |
| **Underground Cable Replacement** | Labour | 689,801 | 734,163 | 792,523 | 827,404 | 868,461 | 876,836 |
| | Contract | 9,795,118 | 10,489,433 | 11,392,453 | 11,972,330 | 12,650,440 | 12,875,332 |
| | Material | 301,444 | 322,812 | 350,602 | 368,448 | 389,318 | 396,239 |
| | Vehicle | 165,843 | 171,989 | 181,500 | 185,366 | 190,717 | 188,211 |
| | Admin | 766,654 | 820,288 | 890,195 | 934,749 | 986,926 | 1,003,563 |
| **Underground Cable Replacement Total** | | **11,718,862** | **12,538,684** | **13,607,273** | **14,288,297** | **15,085,861** | **15,340,181** |
| **Grand Total** | | **17,981,240** | **19,777,241** | **20,923,486** | **22,148,233** | **22,879,979** | **22,249,331** |

b) The blended rate was calculated as shown in Table JTC-1.9b below. The dollar figures can be referenced in Appendix Staff-69. It should be noted that the DS Plan states 30km, while the Cable Report states 25km. The estimates were based on 30km, with an allocation of 20km mainstream, and 10km left behind. These figures are required to be updated in the Cable Report.

As indicated at the technical conference, the optimized values shown in the DS Plan reflect the dollar amounts proposed, and the unit lengths were not updated (hence the variation yearly) after optimization.

**Table JTC-1.9b**

**CABLE REPLACEMENT BLENDED RATE SUMMARY**

| Cable Category | | Planned | | | | |
|---|---|---|---|---|---|---|
| | | 2016 | 2017 | 2018 | 2019 | 2020 |
| Main Stream | Estimated length (m) | 20,000 | 20,000 | 20,000 | 20,000 | 20,000 |
| | $/m | $421 | $434 | $447 | $460 | $474 |
| | $ | $8,420,000 | $8,672,600 | $8,932,778 | $9,200,761 | $9,476,784 |
| Left Behind | Estimated length (m) | 10,000 | 10,000 | 10,000 | 10,000 | 10,000 |
| | $/m | $515 | $530 | $546 | $563 | $580 |
| | $ | $5,150,000 | $5,304,500 | $5,463,635 | $5,627,544 | $5,796,370 |
| Total pre-optimized | $ | $13,570,000 | $13,977,100 | $14,396,413 | $14,828,305 | $15,273,155 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Total | Estimated length (m) | 30,000 | 30,000 | 30,000 | 30,000 | 30,000 |
| DSP Submission | $ | 12,538,684 | 13,607,273 | 14,288,297 | 15,085,861 | 15,340,181 |

**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**

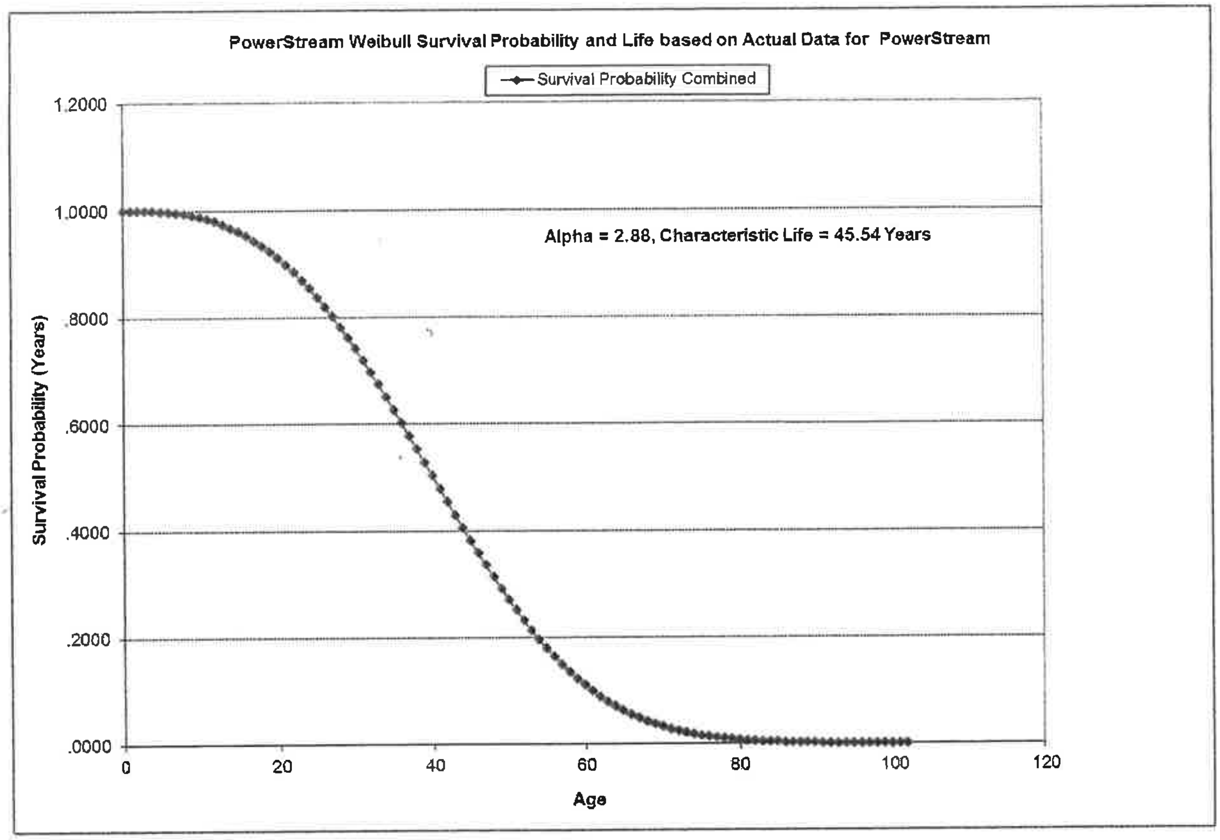
SUMMARY OUTPUT

| *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 |

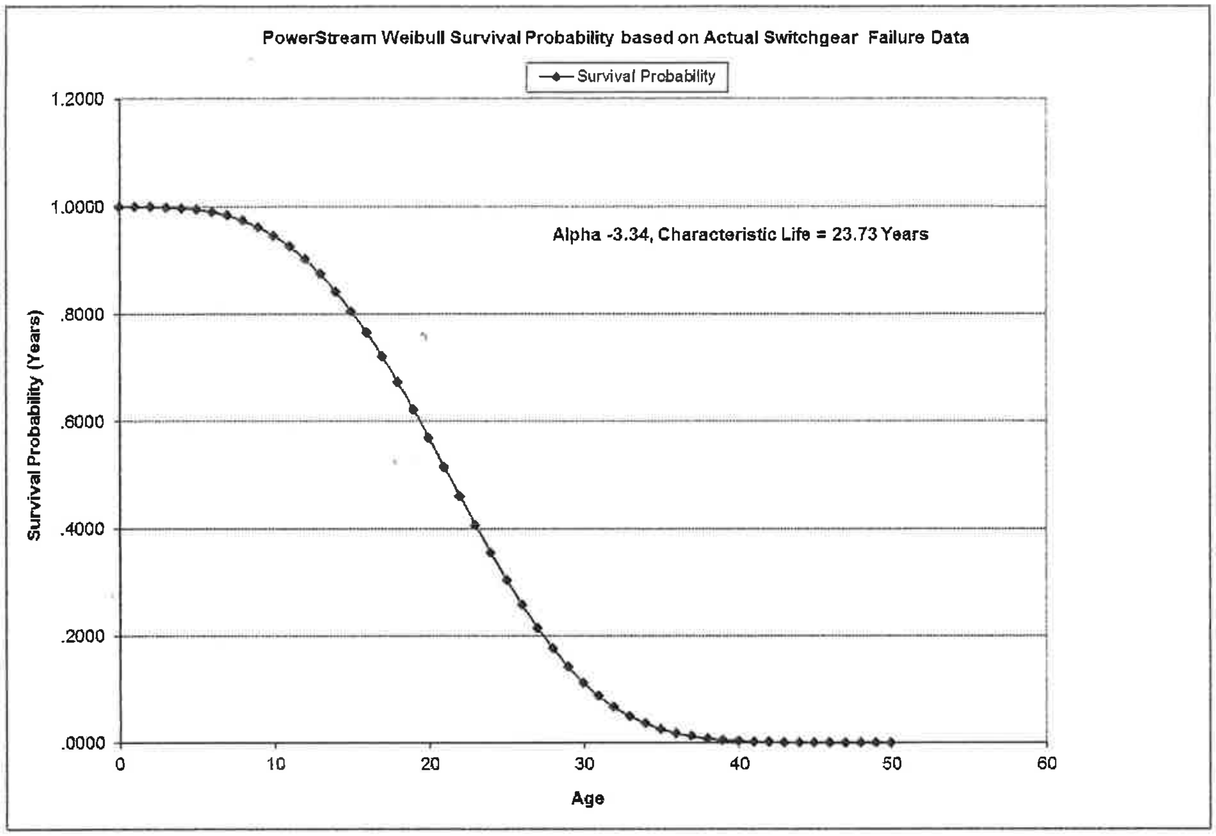
**Distribution Characteristics:**

| | 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-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) US - 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-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.

For Cable Injection: 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.

# 5.3.3 ASSET LIFECYCLE OPTIMIZATION POLICIES AND PROCEDURES

*An understanding of a distributor's asset lifecycle optimization policies and practices will support the regulatory assessment of system renewal investments and decisions to refurbish rather than replace system assets. Information provided should be sufficient to show the trade-off between spending on new capital (i.e. replacement) and life-extending refurbishment, and should include but need not be limited to:*

*a) A description of asset lifecycle optimization policies and practices, including but not necessarily limited to:*

- *a description of asset replacement and refurbishment policies, including an explanation of how (e.g. processes; tools) system renewal program spending is optimized, prioritized and scheduled to align with budget envelopes; and how the impact of system renewal investments on routine system O&M is assessed;*
- *a description of maintenance planning criteria and assumptions; and*
- *a description of routine and preventative inspection and maintenance policies, practices and programmes (can include references to the DSC).*

*b) A description of asset life cycle risk management policies and practices, assessment methods and approaches to mitigation, including but not necessarily limited to the methods used; types of information inputs and outputs; and how conclusions of risk analyses are used to select and prioritize capital expenditures.*

## Asset Replacement and Refurbishment (Remediation) Program and Policies

PowerStream has several asset remediation programs for maintaining distribution system and general plant integrity.

PowerStream makes assessments on whether an aged asset is suited for refurbishment or replacement based on criteria that are pertinent to a given asset class.

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 interrupter 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 B or Code C:

- Code A: Corrective measures/follow-up are required at the earliest possible opportunity (address immediately);
- Code B: Assessment required for corrective action for the next budget cycle; and
- Code C: No corrective measures are required. Follow the regular maintenance cycle.

Additionally, testing is performed on cables to determine the health of the cable, and testing is performed on wood poles to determine remaining strength.

These designations are applied to the distribution system assets as seen in Figure 1. This table depicts, by asset, what the health index scores mean, what the inspection results mean, and how the scores are prioritized

| Program | Health Index (max score = 100) | Inspection Results (Code A, B, C) | Prioritization Score (max score = 100) |
|---|---|---|---|
| Pole Replacement | not applicable | Used field inspection results to select replacement candidates.<br><br>Code A= Very Bad, immediate replacement<br>Code B= Fair, replacement candidate for next budget cycle<br>Code C= Good condition, no replacement needed and maintain inspection | A higher point total yields greater replacement priority. (scored from % Remaining Strength, Condition, # of Transformers, # of Primary Conductors, # of Switches, Criticality of Pole and Age of Pole.)<br>NOTE: Candidates will belong to one of the following groupings:<br>- Remaining strength is less than 60%<br>- Remaining strength is greater than 60%, however other aspects of the pole are bad. (i.e., butt rot, insect infestation, decay, splitting, bending, leaning) |
| Cable Remediation: Cable Replacement | not applicable | TAN DELTA TEST RESULTS<br>Code A = Critically Aged. Intervention Required<br>Code B = Aged. Further study required. (Repeat testing evey 2 years based on test reults)<br>Code C = No Action Required/Repeat after 5 Years | A higher point total yields greater replacement priority. (scored from Age, Cable Condition, Service Quality and Financial Impact) |
| Cable Remediation: Cable Injection | not applicable | TAN DELTA TEST RESULTS<br>Code A = Critically Aged. Intervention Required<br>Code B = Aged. Further study required. (Repeat testing very 2 years based on test results)<br>Code C = No Action Required/Repeat after 5 Years | A higher point total yields greater replacement priority. (scored from Age, Cable Condition, Service Quality and Financial Impact) |
| Switchgear Replacement | Good Condition= high Health Index, >70<br>Fair Condition= middle Health Index, 51-70<br>Poor Condition= low Health Index, <51 | Used field inspection results to select replacement candidates.<br><br>Code A= Very Bad, immediate replacement<br>Code B= Fair, replacement candidate for next budget cycle<br>Code C= Good condition, no replacement needed and maintain inspection | not applicable |
| Mini-Rupter Switch Replacement | Good Condition= high Health Index, >70<br>Fair Condition= middle Health Index, 51-70<br>Poor Condition= low Health Index, <51 | Used field inspection results to select replacement candidates.<br><br>Code A= Very Bad, immediate replacement<br>Code B= Fair, replacement candidate for next budget cycle<br>Code C= Good condition, no replacement needed and maintain inspection | not applicable |
| Automated Switch Replacement | (Good Condition= high Health Index, >70<br>Fair Condition= middle Health Index, 51-70<br>Poor Condition= low Health Index, <51 | Used field inspection results to select replacement candidates.<br><br>Code A= Very Bad, immediate replacement<br>Code B= Fair, replacement candidate for next budget cycle<br>Code C= Good condition, no replacement needed and maintain inspection | not applicable |
| Submersible Transformer Replacement | Good Condition= high Health Index, >70<br>Fair Condition= middle Health Index, 51-70<br>Poor Condition= low Health Index, <51 | Used field inspection results to select replacement candidates.<br><br>Code A= Very Bad, immediate replacement<br>Code B= Fair, replacement candidate for next budget cycle<br>Code C= Good condition, no replacement needed and maintain inspection | not applicable |
| Distribution Transformer Replacement | Good Condition= high Health Index, >70<br>Fair Condition= middle Health Index, 51-70<br>Poor Condition= low Health Index, <51 | Used field inspection results to select replacement candidates.<br><br>Code A= Very Bad, immediate replacement<br>Code B= Fair, replacement candidate for next budget cycle<br>Code C= Good condition, no replacement needed and maintain inspection | not applicable |
| Station Equipment Replacement | Good Condition= high Health Index, >70<br>Fair Condition= middle Health Index, 51-70<br>Poor Condition= low Health Index, <51 | NOTE: Inspection & testing results are used to generate the health index and replacement candidates. | not applicable |

Figure 1: Summary of Health Index Results, Inspection and Testing

**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.

PowerStream anticipates additions from 2015 to 2020 to increase at a similar rate. The result is that the O&M budget requirement is not expected to decrease and in fact increases annually. With the exception of vegetation management, the year-over-year growth in O&M budgets are small, despite the growing asset base (as shown in Table 2, page 26).

Emergency/Reactive Replacements

Although system renewal projects and emergency/reactive replacements are interrelated, a portion of emergency/reactive replacements are directed to activities that are independent of particular capital expenditure levels, including:

- corrective maintenance activities to address deficiencies caused by animal, pest, or tree contacts;
- emergency maintenance resulting from vehicular accidents/vandalism;
- emergency maintenance resulting from severe weather and storms;
- equipment failure due to deteriorated condition; and
- equipment in poor condition as identified during system inspections.

PowerStream's system renewal program has been designed to:

- Hold system failures, and consequently, reliability, at a constant level (not get worse);
- Strike a balance between affordable spending and tolerable risk; and
- Result in the levelling of capital reactive spending (emergency replacements).

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. If proactive replacement of the worst assets can be performed, the level of anticipated failures can be held to a steady state.

**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.

**Optimized, Prioritized Spending Procedures and Risk Management**

PowerStream's Capital Investment Process commences with the annual business planning and budgeting process in the first quarter of each year, as described in Exhibit G, Tab 2, Section 5.3.1, page 25.

The following principles are applied on an annual basis to the process:

- Business Units develop their initial five year capital plans as part of the annual capital planning cycle;
- Business units prepare detailed budgets, justifications and business cases for projects, and enter these into the Optimization tool;
- A Corporate Five Year Plan is compiled based on the submitted business unit five proposed projects/programs as part of the capital planning cycle;
- The five year detailed budgets for all business units are prioritized through the Optimization process; and
- Approved and prioritized projects for years one and two are designed and readied for execution in the next business year(s). Approved and prioritized projects for the remaining three years are identified and design can be commenced only if warranted.

For the five year budget cycle, these principles are applied across ten key steps as shown in Figure 5. The detailed activities in each step are discussed in the following pages.

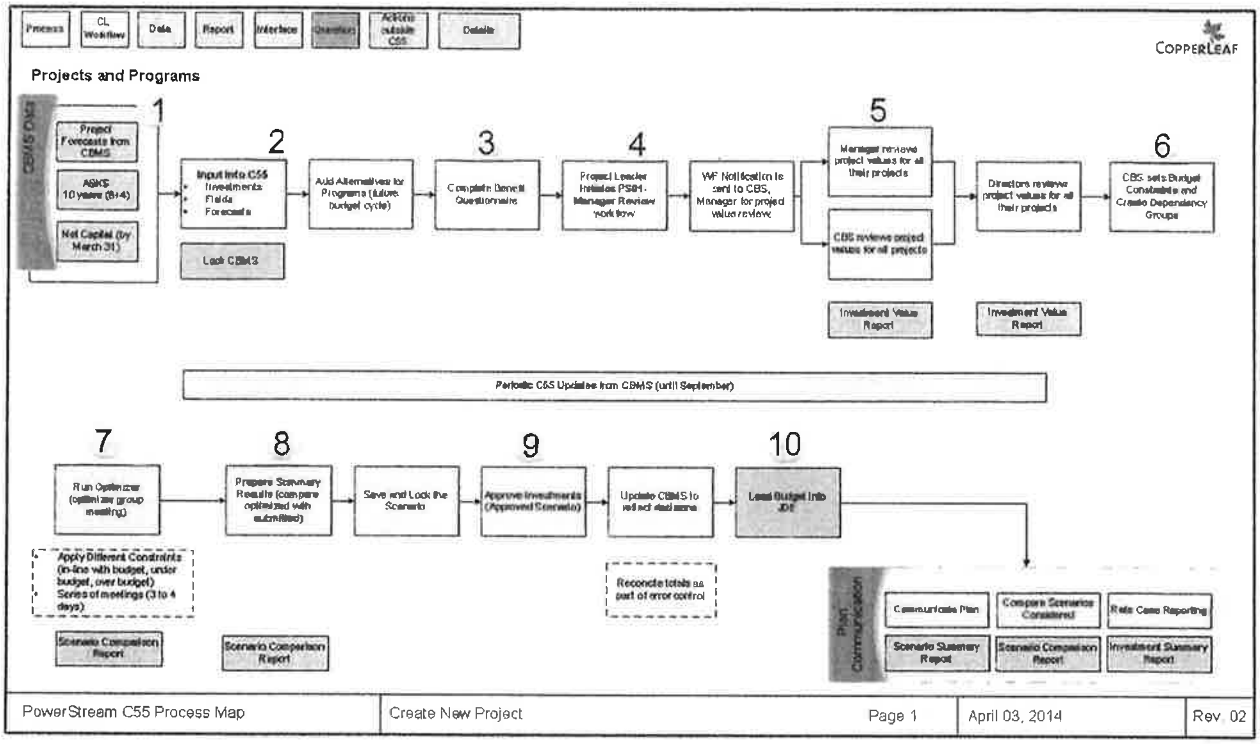



Figure 5: Capital Budget Cycle

Key Step One – Capital Budget Management System (CBMS) Entry

The Capital Budget Management System is one of the first tools applied in the budget cycle. PowerStream's Capital Investment Process incorporates a ten year forward looking plan. Business units that have major capital expenditures put together their own ten year departmental capital expenditure plans and five year budgets.

The business unit ten year capital expenditure plans are summarized into a Corporate Ten Year Capital Expenditure Plan. The information is combined from the following business units:

- Asset Investment Planning;
- Distribution Design;
- Operations;
- Lines;
- Supply Chain Services;

- Smart Grid & Metering; and
- Information Services.

Early in the calendar year a request is sent out by Asset Investment Planning to all business units in PowerStream to prepare ten year capital expenditure plans and five year budgets. These plans are developed over the January to March period. The information in the Corporate Ten Year Capital Expenditure Plan is used by the Finance Department in their financial models to consider affordability. In addition, information in the first five year plan is used in rate planning for the forward looking years.

In 2014, all project leads entered their project information (costs, year of expenditure, rationale etc.) into the Capital Budget Management System (CBMS) tool, which is then loaded into the Optimization tool for review and consolidation. In 2015, for efficiency gains, a project will be proposed to allow direct entry of the budget data into the optimization tool. Refer to Exhibit G, Tab 2, Section 5.2.3 page 7, for additional information.

These five year plans serve as the starting base for the development of the Corporate Capital Expenditure Plan.

The business unit capital plans serve three purposes:

i) assist business units in their future planning and enable the business units to provide solid five year budgets;
ii) forms the basis of the information provided in a rate application for the forward looking years; and
iii) provides the Finance team with information for financial planning.

Business units provide details in their five year budgets on forecast capital spending requirements and describe the process by which they have determined the capital spending requirements. Specific projects/programs and costs identified in the plans are generally preliminary and the projects/programs identified in the plans may or may not be approved for execution at this point.

Key Step Two – Input Data into Optimization Tool (Input into C55)

Data is entered into the Copperleaf C55 Optimization tool. Critical fields are entered including details on the proposed investment, forecasts of the expenditures over the five year budget horizon, answers to specific questions asked, based on the investment type, for both benefit and risk.

The value and risk questionnaire was created using vendor expertise, existing practices and the contribution of project leads as experts who request capital projects or programs.

Within Copperleaf's C55 program, all projects are valued (and optimized) based upon a Value Function. The Value Function is a weighting of a number of Value Measures. Value Measures can include risk mitigation, financial benefits, impacts on Key Performance Indicators (KPI), and cost. The Value Function was configured to reflect how projects contribute to PowerStream's strategic objectives as shown below. Questions were designed to provide value and scoring for these strategic elements, as noted in Exhibit G, Tab 2, Section 5.2.1, Figure 1.

**Financial Benefits:**

- Hard Financial Benefits
- Soft Financial Benefits

Productivity

| 4 Pillars | Corporate Strategic Objective |
|---|---|
| Financial | F2 (provide an optimized rate of return) |
| Processes | I1 (focus on continuous improvement) |

**KPI Impacts:**

- Reliability
-
- Reliability for Spares
-
- Customer Communication

- Customer Service
-
- Rate Ready Organization
- Environmental Improvements
- Employee Wellness
- Technological Innovation

| | |
|---|---|
| Customers | C1 (deliver professional services and exceptiopnal customer experience) |
| Customers | C1 (deliver professional services and exceptiopnal customer experience) |
| Customers | C3 (continue developing the PowerStream brand) |
| Customers | C1 (deliver professional services and exceptiopnal customer experience) |
| Processes | I4 (develop a rate submission ready organization) |
| Foundation | E2 (ensure a safe and healthy workplace) |
| Foundation | E1 (be a best in class employer) |
| Foundation | E4 (investigate and apply new and innovative technologies) |

**Risk Mitigation:**

- IT Capacity
- Financial
- Environmental
- Safety
- Distribution
- Compliance

| | |
|---|---|
| Foundation | E3 (build integrated technoogy platforms) |
| Financial | F2 (provide an optimaized rate of return) |
| Foundation | E1 (be a best in class employer) |
| Foundation | E2 (ensure a safe and healthy workplace) |
| Customers | C2 (provide customer swith cost effective, competive distribution rates) |
| Processes | I3 (Shape and Influence positive advocacy) |

**Cost:**

- Project Cost

| | |
|---|---|
| Financials | F1 (increase shareholder value) |

Key Step Three – Complete Benefit Questionnaire

Once project identification is complete, the business units, in conjunction with the Capital Budget Supervisor, answer a series of questions about each project/program. The questions posed are aligned with PowerStream's corporate goals and risk matrix.

The answers to the questions form the basis for scoring both the value of the project to the corporation and its customers if the project is undertaken and the risk to the corporation and its customers if the project is not completed in the planned year. The Capital Budget Supervisor coordinates the business units across the organization to ensure that timelines are met, and consistent interpretations of the answers are applied.

In addition to answering the benefit and risk questions required for scoring the projects/programs, for those projects/programs that exceed the materiality threshold, additional questions with respect to Chapter 5 of this rate filing are posed and business leads are required to provide the requisite information. Business cases, as appropriate, are also created. Once the questions on the projects are all answered, the data on the projects is ready for optimization. PowerStream utilizes Copperleaf's C55 product for optimizing multi-year portfolios.

The current configuration of PowerStream's Value Function and the Value Measures that comprise the Value Function is summarized below:

- Each of the Value Measures is calibrated to the same scale (1 value point approximately equal to $1000). Consequently, within the Value Function, each of the Value Measures (except Project Cost) is weighed with the same value of +1. As Project Cost is a negative contributor to Project Value it is weighted with a cost of -1.
- All Value Measures are computed on an annual basis (e.g. the financial benefits for 2017 can be specified as being different than 2018). The stream of benefits (or costs) is converted to a single value for the Value Measure, by taking the Present Value of the stream, back to the beginning of the current fiscal year. The PV calculation uses the system defined discount rate.

- The Value of Risk Mitigation in all risk categories is computed using the same methodology. The project owner specifies the Baseline Risk and the risk present if the project is not completed.
- Residual Risk: The risk present if the project is completed. The value of Risk Mitigated is computed as: Baseline Risk – Residual Risk.
- For each risk the project owner specifies both the consequence and the probability of Consequence
- Projects in the following categories have been identified as Mandatory or Must Do investments as PowerStream is mandated to complete these investments, specifically:
    - Emergency Restoration;
    - Subdivision Services;
    - Road Authority Projects;
    - Emerging Development Capital;
    - Customer RGEN;
    - ICI projects;
    - Subdivisions;
    - Layouts; and
    - Emerging customers.

These projects are flagged as “must do” and are considered as mandatory as part of the optimization process. These projects have mitigated risk value as they are mitigating a compliance risk. These projects are subtracted, by the system, from the constraint amount, effectively reducing the amount of money available for competing projects and programs.

The value function combines all the value measures to compute the overall value of an investment. The value of an investment reflects the total value that the project is bringing to PowerStream, taking into account all of its financial benefits, impact on KPIs, risk mitigation and costs.

Key Step Four – Initiate Manager Review

Once a project lead has completed a project/program entry into C55, and automatic workflow notification is produced to advise the Manager, Director or VP and the Capital Budget Supervisor that the item is ready for review.

Key Step Five – Manager Review Projects/Program Values

Once a project/program, or series of projects/programs have been entered by project leads, their respective managers, directors or vice-presidents can review, on an individual or comparative basis, projects under their purview. Once reviewed and any follow-up questions answered, the projects/programs are then ready for the optimization process.

Key Step Six – Set Budget Constraint

The Finance department sets several budget funding level constraints to allow for analysis and to establish financial criteria to permit the optimization results to be compared to the optimal funding amount. These levels are available for optimization runs to create varied constraint scenarios.

Key Step Seven – Run the Optimization

The C55 tool is capable of running multiple scenarios with the project/program list being optimized for the greatest annual value. All capital projects/programs in the corporation are run through the Optimizer tool with projects from IT, fleet, planning, station construction and lines construction competing on value through the same tool. The multiple scenarios permit the results to be compared under various constraints and risks. The software tool takes all the projects/programs within the capital portfolio, calculates a numeric dollar value based on the benefit and risk calculations and the initial capital cost, and uses that value in the optimization process.

The C55 optimizer selects the combination of start dates of projects that brings the highest total value to PowerStream while fitting within the specified financial constraints.

Until projects are compared with one or another and the financial constraints are specified it is not known whether a project will be funded or not – so a project lead cannot know for certain whether or not a project will be funded.

Key Step Eight – Prepare the Results of the Various Scenarios

With the constraints set and the "must do" projects/programs accounted for, the results of the various scenarios are presented and reviewed by a multi-departmental senior optimization team, who discuss which projects must be approved as part of the five year capital budget. Members of the senior optimizer team include key leaders from each of the business units who have major capital spend across the corporation, as well as Rates & Regulatory department and Organizational Effectiveness department representatives.

Projects that were scored negative, are generally deferred beyond the six year horizon but are also discussed to ensure that any intangible benefits are considered. Once reviews and dependencies are considered, optimization can be run several times to achieve that optimal balance between the computation (science) and human element (art).

A decision is made on the preferred constraint scenario, and any project/program adjustments and deliberations occur prior to finalizing the preferred listing.

Key Step Nine - Determining and Approving the Portfolio of Projects/Programs

The result from the senior optimization team is a proposed scenario of multi-year projects and programs that will be approved by the PowerStream's Executive Management Team (EMT) and the Audit and Finance Committee for approval prior to approval by the Board of Directors.

The proposed scenario is submitted for approval with the appropriate business case details. For projects less than $500,000 the information is in its "mini-business case" format for each project. For any specific project or program that is greater than $500,000 or for IT related projects greater than $100,000, a full business case is provided and submitted for approval.

In conjunction with this process, for a rate filing year, the DS Plan's Customer Engagement process, as detailed in Exhibit G, Tab 2, Section 5.4.2, considers the responses of PowerStream's customers and a detailed review is held to correlate the proposed plan to the engagement results.

Key Step Ten – Load the Approved Portfolio into JD Edwards

The approved first year portfolio of projects/programs is loaded into the JD Edwards financial system so that it is available for all departments use within the project execution process, enabling project/program implementation.

**Maintenance Planning Criteria and Assumptions**

PowerStream has two main capital activities related to maintenance, which are planned and unplanned maintenance.

Planned (Proactive) Inspection and Maintenance

Activities associated with PowerStream's annual distribution inspection and preventative maintenance program are detailed in Table 2. When an inspection is performed on a given set of assets, a rating code is assigned. If the rating code assigned warrants immediate replacement, the replacement cost will generally be capitalized, while repairs will generally be expensed.

**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.

| | 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 |

1

**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**

| [illegible] | [illegible] | [illegible] | [illegible] |
|---|---|---|---|
| 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**

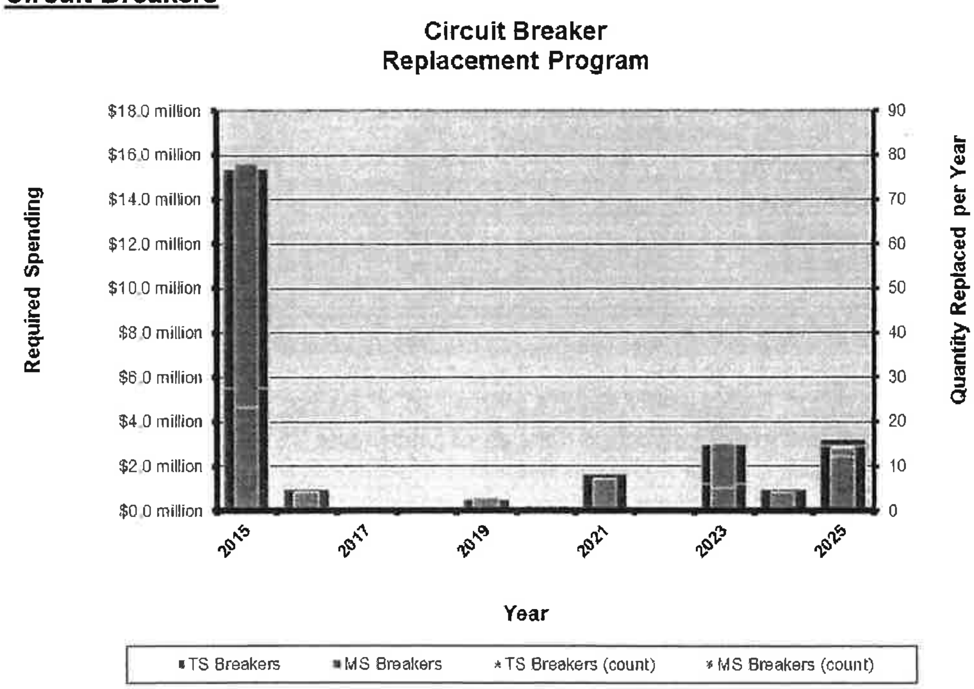
| [illegible] | [illegible] | [illegible] |
|---|---|---|
| Power Transformers (TS & MS) | 2014 | Yearly |
| Circuit Breakers (TS & MS) | 2014 | Yearly |
| Primary Switches (TS & MS) | 2014 | Yearly |
| 230kV Primary Metering Units | 2014 | Yearly |
| Station Reactors (TS) | 2014 | Yearly |
| Capacitor 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 |

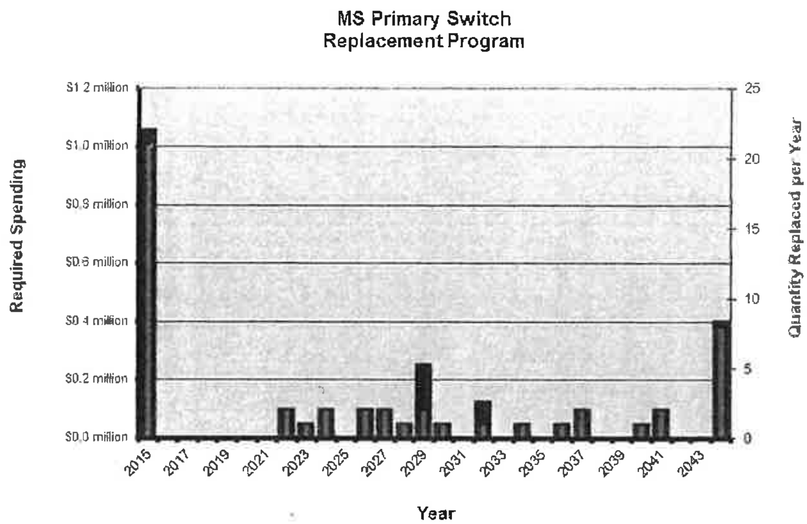
d) The updated Risk-based economic analysis and Econometric replacement results are summarized below.

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

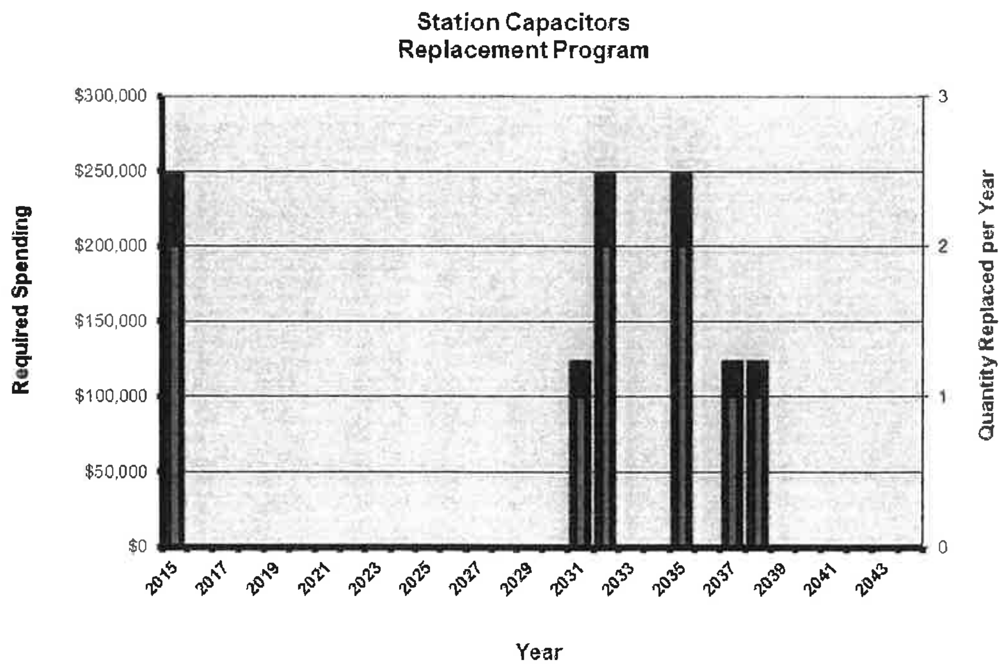
## Circuit Breakers



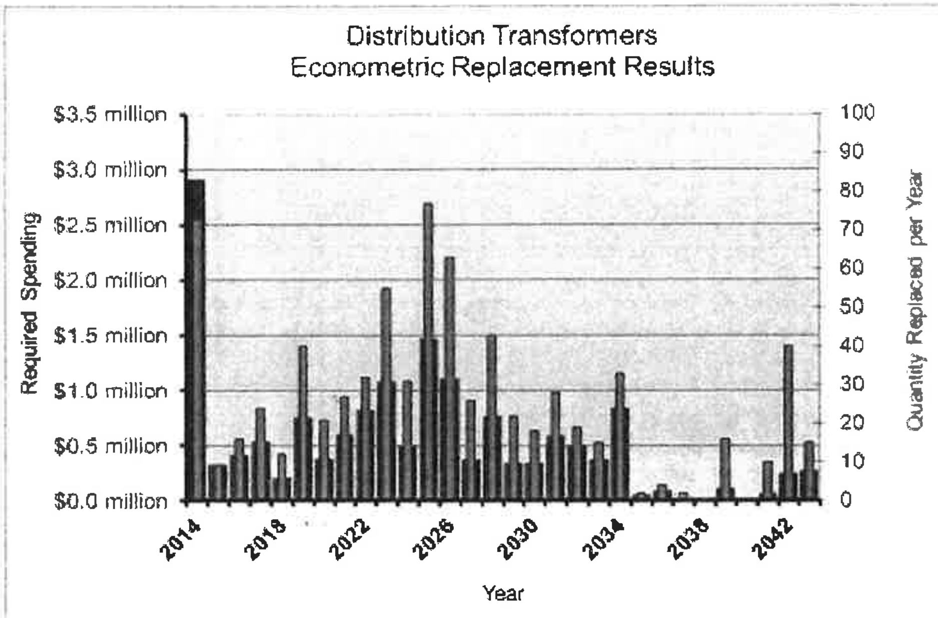

## MS Primary Switches



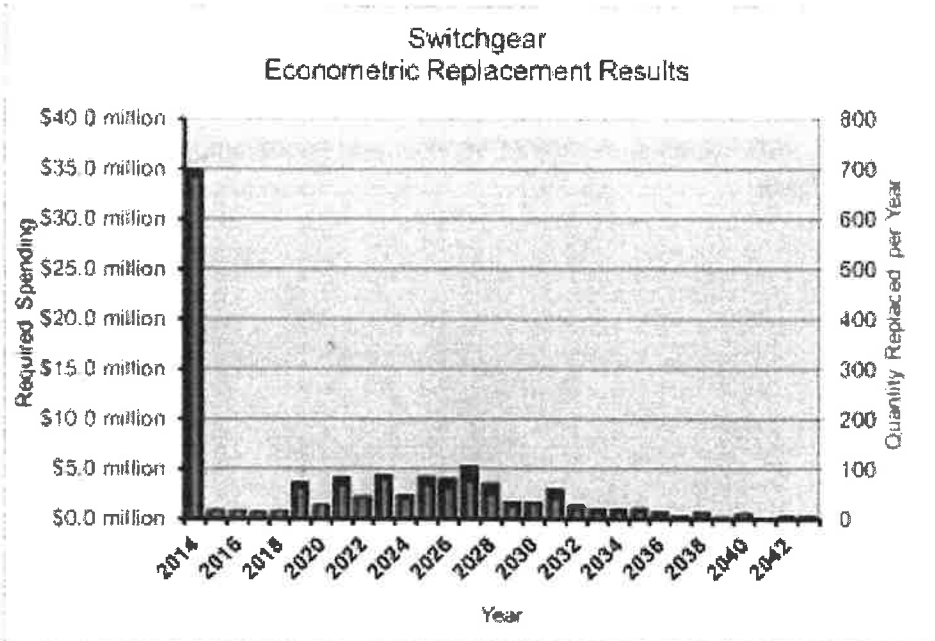

## Capacitor Banks




## Distribution Transformers


Distribution Transformers
Econometric Replacement Results
$3.5 million
$3.0 million
$2.5 million
$2.0 million
$1.5 million
$1.0 million
$0.5 million
$0.0 million
Required Spending
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-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.

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**FILE NO.:** **EB-2015-0003** **PowerStream**

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**VOLUME:** **Technical Conference**

**DATE:** **September 9, 2015**

MR. HJARTARSON: Okay, thank you.

1 Staff 18, and you had provided a number of figures which are econometric replacement results, and we wanted to understand why there were no such figures for wood poles and underground primary cables in the response.

MR. SHAIKH: We don't do econometric analysis for wood pole and cables, we just have the prioritization index as explained in that ESP.

MR. HJARTARSON: Is there a specific reason why you don't do that or...

MR. SHAIKH: Well, the specific reason, I can just say that it would be very cumbersome to do for each cable segment. It wouldn't be physically possible to do it for each cable segment econometric analysis.

MR. HJARTARSON: The second part of that, can you provide the rationale for not including the replacement of MS primary switches and capacitor banks in the renewal program as indicated by the econometric replacement results for these parts in the answer, or are they maybe perhaps hidden somewhere else?

MR. SHAIKH: No, we are [redacted] banks or the MS switches. Especially this econometric analysis is just for the overall picture. We are looking at the condition based - all of our assets are replaced based on condition. The condition of those two assets doesn't warrant replacement right now, so that is why they are not included.

MR. HJARTARSON: Okay, thank you.

Lastly, similar -- the number of distribution transformers planned to be replaced in 2015 to 2020 are 360, which far exceed

**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 2011 | Actual 2012 | Actual 2013 | Actual 2014 | Planned 2015 | Planned 2016 | Planned 2017 | Planned 2018 | Planned 2019 | Planned 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

**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-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).

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**FILE NO.:** EB-2015-0003 PowerStream

**VOLUME:** Technical Conference

**DATE:** September 9, 2015

Thank you. 2 Staff 70; there is a Table 70 A, where PowerStream shows cable injection and replacement projects in 2012 with a number of cable failures for each area in 2011. The total sum of all of the cable failures in mentioned areas is 117 in 2011.

On Figure 2, an updated asset condition report, appendix 69, the total number of cable failures in the system is only 103 in 2011.

Maybe that's something that could be subject to check, which data point is correct.

MR. SHAIKH: I think in this case it might be the cable failures that happened in that areas right up to 2011. So it might be including failures for the previous years as well.

MR. HJARTARSON: Yes, so it's says 117 and 103 was the other number.

MR. SHAIKH: Yes.

MR. HJARTARSON: So it might not be over the same period, you're saying?

MR. SHAIKH: Exactly.

MR. HJARTARSON: Okay, thank you. 2 Staff 74; in its response, PowerStream states that it expects a number of units will transition from fair, good, very good condition to poor and very poor, and therefore required replacement as per the proposed rates in the filing.

Has PowerStream completed any analysis to value asset condition transitions between condition states on which it can base its proposed replacement strategy -- that is how it moves from fair to poor, and so on over time?

MR. SHAIKH: I think we have not done that analysis in terms of when it moves from fair to poor. We just look at -- these are based on the inspection results for that period, for the five-year period.

So every year we do one fifth of the assets, which are inspected each year. So those are a moving target based on the inspection results each year.

MR. HJARTARSON: So the plans you have are not -- they don't include those transitions. You expect from some good assets to go into poor, as such.

MR. SHAIKH: No, they include the transitions, but it is just an [redacted] out -- okay, based on the previous experience, we figure out that maybe two or three percent of the population will move into the poor condition.

MR. HJARTARSON: And would you have those kind of calculations of previous experience, or --

MR. SHAIKH: I would -- that would be difficult for the mini rupter switches, because we didn't have -- we didn’t develop the model for mini-rupter switches up until last -- in 2013, we developed the model.

MR. HJARTARSON: Okay, that's fine.

**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-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-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 | 103026 | 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-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.

**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 |

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

**JTC 1.10: To confirm that PowerStream applied hourly customer interruption cost of $1.20 per kilowatt-hour for duration of the customer minutes interrupted, not customer hour interrupted, because there's a factor of 60 between those two, and that when it comes to benefit calculations this was considered.**

**RESPONSE:**

PowerStream applied $20/kWhr (not $1.20/kWhr) as the duration cost in its calculations. PowerStream does not use the cost per CMI in its calculations.

In order to answer the specific questions (II-2-Staff -58 and II-2-Staff-53 g) in the format as requested by OEB staff - *"Cost ($) / (CMI Savings * Customer Interruption Cost)"*, PowerStream calculated the cost per CMI.

The calculation was completed using the $20/kWhr for the duration cost and $20 per kW for the frequency cost. As such, the number PowerStream used in the formula requested by OEB staff is in customer minutes and not customer hours. The derivation of the total cost per CMI is seen in Table JTC-1.10.

**Table JTC-1.10**

| | Year | Energy (kWhr) | Average Daily Peak (kW) |
|---|---|---|---|
| | 2012 | 8,766,473,303 | 1,199,949 |
| | 2013 | 8,716,825,089 | 1,186,309 |
| | 2014 | 8,670,740,684 | 1,175,979 |
| | Average | 8,718,013,025 | 1,187,412 |
| | No of Customer | 346,943 | |
| | | | |
| | Duration Cost | | |
| A | Average Energy Lost per hour (kWhr)=Energy Delivered /(365*24) | | 995,206.97 |
| B | Duration Cost = $ 20/kWhr | | 20 |
| C | Duration Cost System Wide per hour ($) = A X B | | 19,904,139.33 |
| E | Duration Cost per Customer per hour ($)= C/No of Customer | | $57.37 |
| F | Duration Cost per Customer per Minute($) = E/60 | | $0.96 |
| | | | |
| | Frequency Cost | | |
| G | Average Peak (KW) | | 1,187,412.33 |
| H | Frequency Cost ( $20/kW) | | 20 |
| I | Frequency Cost System Wide ($) =G*H | | 23,748,246.67 |
| J | Frequency Cost System Wide for each Outage ($)= H/No of Customer | | 68.45 |
| | Average System SAIFI Excluding LOS/MED over past three year | | 1.01 |
| | | | |
| | Total Cost per CMI= F+J | | $69.41 |

**JTC 1.13: To ask the consultant to provide the background to the 1.47 factor.**

**RESPONSE:**

The 1.47 factor used by CIMA was derived from the initial report prepared by PowerStream comparing estimates between Option 3 and Option 4 for one typical project.

**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.

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**FILE NO.:** **EB-2015-0003** **PowerStream**

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**VOLUME:** **Technical Conference**

**DATE:** **September 9, 2015**

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MR. HJARTARSON: Okay, that's fine. 2 Staff 86; this is about new subdivisions.

In its response, PowerStream states that there are no reliable leading indicators that could be used to forecast activity with any degree of accuracy for this type of development.

So based on that, we would like to have PowerStream explain how it has forecast a significantly and consistently higher capital based on the above statement.

In other words, if the there are no reliable leading indicators, how can you still significantly forecast higher capi?

MS. CUNNINGHAM: So we know that we will get some [redacted]s over the next period. The problem is we don't know how big it's going to be in a given year, and you can see from the history and the spending that it is all over.

And so all we really have to go on is essentially the intel from some of our developers and discussions with them, and get a bit of an idea what projects might be out there, but we don't know the time frame.

And so it's the combination of listening to that -- those people and the fact that we have had spend in the last number of years, and so we try to take somewhat number that is indicated between those pieces of information and do the estimate that way, since we do know that we are going to have commercial subdivisions.

MR. HJARTARSON: Okay, thank you.

Another part of the answer which actually talk about that it's consistently higher for those residential subdivisions is primarily due to accounting treatments that were made to reflect regulatory and process changes.

Could you explain what these are, what these regulatory and process changes are?

MS. CUNNINGHAM: So there is a couple of things that have contributed to the differences in costs from the prior period to the future period. When it comes to things like accounting treatments, back in 2013 we no longer had upstream charges within residential subdivisions that cause costs to be increased.

When it came to -- the other thing on accounting treatments is how we were pulling the data with relationship to some costs that were exclusive to the developer was not consistent, so it caused the lower period numbers to be lower.

And there is a significant variability in the prior period numbers with respect to the timing of receiving funds compared to the contributed costs compared to when the subdivision is actually constructed, and we don't forecast that variability going forward because it's too difficult to do so.

MR. HJARTARSON: Is it possible to kind of quantify this type of impact that you have just described?

MS. CUNNINGHAM: I am going to say it's going be very difficult because, to be fair, it's been difficult for us to get a handle on it, and it is just because of the way the reports were pulled, and there was some inconsistencies in the past of how they are pulled, and it's difficult to go back and figure those out.

MR. HJARTARSON: Thank you.

**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.

| Material Investments | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|
| **General Plant** | **($ )** | **($ )** | **($ )** | **($ )** | **($ )** | **($)** |
| **Customer Information System (CIS)** | | | | | | |
| CIS Modifications | 1,403,400 | 3,884,100 | 6,708,900 | 2,996,000 | 2,996,000 | 2,996,000 |
| CIS Replacement Project | 10,300,000 | - | - | - | - | - |
| **IT & Info/Communication Systems** | | | | | | |
| JD Edwards Application Upgrade | - | - | - | - | 2,396,800 | - |
| MSBPI | - | 10,000 | 60,000 | 899,999 | 50,000 | 10,000 |
| Phone System enhancement Upgrade | - | - | - | - | 50,500 | 908,999 |
| Storage Expansion (Data) | 321,000 | 300,000 | 300,000 | 300,000 | 1,000,000 | 400,000 |
| Work Force Management / Mobile Dispatch | 1,605,000 | 2,675,000 | 802,500 | 802,500 | 535,000 | 535,000 |
| **Buildings & Emerging Operations** | | | | | | |
| Barrie Building Renovation Project 2015 | 3,149,489 | - | - | - | - | - |
| **Fleet** | | | | | | |
| Replace various Light and Medium Duty Vehicles | - | - | - | - | 829,250 | 888,100 |
| Replace various Single Bucket and Double Bucket Trucks | - | - | - | 2,193,500 | 1,605,000 | 1,391,000 |
| **Interest Capitalization** | | | | | | |
| Interest Capitalization | 1,000,000 | 1,020,000 | 1,040,000 | 1,061,000 | 1,082,000 | 1,104,000 |
| **Total Material Investments General Plan** | **17,778,890** | **7,889,100** | **8,911,400** | **8,252,999** | **10,544,550** | **8,233,100** |

Table 5: Material Investments - General Plant

## Regional Planning

As indicated in Exhibit G, Tab 2, Section 5.1.4, PowerStream has participated in Regional Planning, and as a result of this, PowerStream has capital expenditures related to Vaughan Transformer Station #4, and the integration of the feeders from this station to the distribution system. The total proposed capital expenditure for the station and related system integration is $42,046,617 between 2015 and 2020.

## Customer Engagement Activities

As described fully in Exhibit G, Tab 2, Section 5.4.2, PowerStream performed a comprehensive customer engagement process, and have reviewed those results against the proposed plan.

## Five Year System Development

PowerStream's distribution system will continue to expand to accommodate:

- new transformer and municipal station construction;
- the integration of feeders from the stations to the distribution system;
- enhancement of pole lines to accommodate growth areas; and

**JTC 1.10: To confirm that PowerStream applied hourly customer interruption cost of $1.20 per kilowatt-hour for duration of the customer minutes interrupted, not customer hour interrupted, because there's a factor of 60 between those two, and that when it comes to benefit calculations this was considered.**

**RESPONSE:**

PowerStream applied $20/kWhr (not $1.20/kWhr) as the duration cost in its calculations. PowerStream does not use the cost per CMI in its calculations.

In order to answer the specific questions (II-2-Staff -58 and II-2-Staff-53 g) in the format as requested by OEB staff - *"Cost ($) / (CMI Savings * Customer Interruption Cost)"*, PowerStream calculated the cost per CMI.

The calculation was completed using the $20/kWhr for the duration cost and $20 per kW for the frequency cost. As such, the number PowerStream used in the formula requested by OEB staff is in customer minutes and not customer hours. The derivation of the total cost per CMI is seen in Table JTC-1.10.

**Table JTC-1.10**

| | Year | Energy (kWhr) | Average Daily Peak (kW) |
|---|---|---|---|
| | 2012 | 8,766,473,303 | 1,199,949 |
| | 2013 | 8,716,825,089 | 1,186,309 |
| | 2014 | 8,670,740,684 | 1,175,979 |
| | Average | 8,718,013,025 | 1,187,412 |
| | No of Customer | 346,943 | |
| | | | |
| | Duration Cost | | |
| A | Average Energy Lost per hour (kWhr)= Energy Delivered /(365*24) | | 995,206.97 |
| B | Duration Cost = $ 20/kWhr | | 20 |
| C | Duration Cost System Wide per hour ($) = A X B | | 19,904,139.33 |
| E | Duration Cost per Customer per hour ($)= C/No of Customer | | $57.37 |
| F | Duration Cost per Customer per Minute($) = E/60 | | $0.96 |
| | | | |
| | Frequency Cost | | |
| G | Average Peak (KW) | | 1,187,412.33 |
| H | Frequency Cost ( $20/kW) | | 20 |
| I | Frequency Cost System Wide ($) =G*H | | 23,748,246.67 |
| J | Frequency Cost System Wide for each Outage ($)= H/No of Customer | | 68.45 |
| | Average System SAIFI Excluding LOS/MED over past three year | | 1.01 |
| | | | |
| | Total Cost per CMI= F+J | | $69.41 |

**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.

identified and tested, and the results and taken into consideration for the selection of areas for cable remediation. Refer to Exhibit G, Tab 2, Section 5.3.3 for information on the cable remediation program.

*Dry Ice Cleaning*

The dry-ice cleaning program for air-insulated pad-mounted switchgear and vault room switchgear is a cleaning method that allows an efficient and cost effective maintenance of switchgear. Air-insulated switchgear become contaminated with dirt, dust and road salt that can lead to flashovers and equipment failure. The high pressure dry ice method of cleaning allows for air-insulated switchgear to be cleaned without the necessity of isolating the equipment and removing the unit from service. Switchgear is typically cleaned on a six year cycle unless a location is determined to require more frequent cleaning due to high levels of contamination.

*Infrared Scanning*

PowerStream's Lines Department also uses infrared scanning to identify overheating components on its overhead and underground distribution system. As a result of the infrared scanning, equipment showing signs of overheating is scheduled for repair or replacement on a priority level based on the severity of the overheating.

*Overhead Switch Maintenance*

Maintenance of three phase gang operated switches, both manually operated and remotely operated, is required to ensure the switches are free of contamination and operate smoothly and efficiently. PowerStream currently maintains the switches over a five year cycle. Maintenance of overhead switches requires isolation of the switches.

*Vegetation Management*

PowerStream's vegetation management program was historically based on a five-year tree trimming cycle, with adjustments for more densely treed, overhead areas. Targeted tree trimming that is not part of the regular five-year cycle was carried out directly as a result of outages caused by trees and as part of the worst performing feeder program. In assessing the effectiveness of the tree trimming program, it became evident that there was a trend toward increased "reactionary" tree trimming as a result of outages and to meet the needs of the worst performing feeder program. This was diverting resources away from the annual cycle trimming program and upon review it was determined that the five year trimming cycle was not adequate to keep up with tree growth across the service territory. As such the tree trimming cycle has been adjusted to a three year cycle across the territory.

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

Unplanned (Reactive) Maintenance

Activities in this category are typically associated with equipment failures that are usually accompanied by outage trouble shooting and restoration. Power interruptions on the distribution system result from a variety of causes as indicated by the multitude of Canadian Electrical Association (CEA) cause codes. Responses to outages are performed by trouble crews.

Where the repairs made to the distribution system are minor, maintenance work orders are charged. This includes work such as splicing conductors, repairing guying and down grounds on poles, tightening loose attachments, painting rusted tanks, levelling uneven pad bases or repositioning shifted transformers and repairing secondary failures.

**Impact of System Renewal on Routine O&M and Emergency/Reactive Repairs**

Routine O&M

Although System Operations and Maintenance (O&M) and capital investments are interrelated, a significant portion of System O&M expenditures are directed to activities that are independent of specific capital expenditure, including:

- Testing of assets for health condition assessments necessary to provide the information that is used to plan the capital programs;