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

AND IN THE MATTER OF an Application by PowerStream Inc. for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2009

VULNERABLE ENERGY CONSUMERS COALITION

INTERROGATORIES: POWERSTREAM INC.

Vulnerable Energy Consumers Coalition – Interrogatory #1

Reference: Exhibit A1/Tab 4/Schedule 1, page 5

Question:

a) Please redo-Table 3 but exclude the impact of any rate riders related to the disposition of deferral/variance account balances.

Response

a) The table below excludes the impact of regulatory assets rate riders.

Table VECC 1-1: Delivery Charge Impacts Net of Rate Riders

Class	Consumption per customer, kwh	Demand per customer,	January update Distribution Charge $ Change	January update Distribution Charge % Change	Original Distribution Charge $ Change	Original Distribution Charge % Change	Change Distribution Charge $ Change	Change Distribution Charge % Change
Residential	1,000	-	$ 1.45	5.5%	$ 1.21	4.6%	$ 0.24	0.9%
GS<50	2,000	-	$ 2.24	4.2%	$ 1.84	3.5%	$ 0.40	0.8%
GS>50	80,000	250	$ 114.19	12.8%	$ 105.22	11.8%	$ 8.97	1.0%
Large Use	2,800,000	7,350	$ (11,046.47)	-59.5%	$ (11,137.61)	-60.0%	$ 91.14	0.5%
USL	500	-	$ 1.50	7.5%	$ 1.35	6.7%	$ 0.15	0.7%
Sentinel Lighting	180	1	$ 1.41	27.9%	$ 1.49	29.6%	$ (0.08)	-1.6%
Street Lighting	882,119	2,639	$ 4,586.62	7.3%	$ 5,295.01	8.5%	$ (708.39)	-1.2%

Vulnerable Energy Consumers Coalition – Interrogatory #2

Reference: Exhibit A2/Tab 1/Schedule 1, page 7

Question:

a) Please confirm whether the values set out in Table 1 for 2008 are forecast values or actual 2008 values.

b) With respect to Table 1, for those years based on actual results, please clarify the basis on which the "target net income" value was determined (i.e., is it based on the deemed equity portion of the actual rate base x the allowed ROE?).

Response

a) The values set out in Table 1 for 2008 are estimated values.

b) For the comparative purpose, the calculation of "target net income" for 2006-2008 was performed using the same logic, as the "target net income" for the rebasing year, i.e. it is based on the deemed equity portion of the calculated rate base multiplied by allowed ROE.

Vulnerable Energy Consumers Coalition – Interrogatory #3

Reference: Exhibit A2/Tab 1/Schedule 1, page 13

Question:

a) For each customer class set out in Table 5 please indicate the average kWh per customer use forecast for 2009.

Response

a) **Table VECC 3-1: Average Consumption per Customer**

	Test Year 2009 kWh/customer
Residential	9,326
GS Less Than 50 kW	33,887
GS 50 to 4,999 kW	997,017
GS 50 to 4,999 kW Legacy	28,037,810
Large Use	31,414,814
Unmetered Scattered Load	3,865
Sentinel Lighting	4,809
Street Lighting	664

Vulnerable Energy Consumers Coalition – Interrogatory #4

Reference: Exhibit A2/Tab 1/Schedule 2, page 1

Question:

a) Please confirm whether the revenue deficiency calculation excludes the costs and current rate adders related to HONI's LV charges.

Response

a) PowerStream confirms that the revenue deficiency calculation excludes the costs and current rate adders related to LV charges.

Vulnerable Energy Consumers Coalition – Interrogatory #5

Reference: Exhibit A2/Tab 2/Schedule 1, page 1

Question:

a) Has PowerStream prepared and/or is PowerStream in the process of preparing a two-year OM&A budget for the period 2009-2010?

b) If the response to part (a) is no please explain why given the "good business practice" reference on lines 4-5.

c) If answer to part (a) is yes please provide the following:

- **The current status of the budget's preparation and approval**
- **Copy of the 2009-2010 Budget Guidelines**
- **If the budget has been approved by PowerStream's Board of Directors, a copy of the approved budget and the material presented to the Board.**
- **If the budget has not been approved by the Board of Directors but budget recommendations have been provided to PowerStream's Audit and Finance Committee, please provide.**

Response

a) PowerStream has prepared a two-year OM&A budget for the period 2009-2010.

b) Not applicable.

c)

- The OM&A budget has been prepared and was approved by the Board of Directors on December 10, 2008.
- A copy of the 2009-2010 Budget Guidelines is attached as Schedule VECC 5-1
- A copy of the approved budget is attached as Schedule VECC 5-2. The material presented to the Board is attached as Schedule VECC 5-3
- Not applicable.

Vulnerable Energy Consumers Coalition – Interrogatory #6

Reference: Exhibit A2/Tab 3/Schedule 1, pages 2-3

Question:

a) Please describe the timeframe over which the $4.7 M in capital spending savings and the increase of $2.4 M in OM&A costs are expected to occur (e.g., are they both for 2009?).

b) Please explain why all the expected capital savings are avoided costs for the Barrie Division.

c) Please describe what degree of integration between the PowerStream and Barrie Divisions is expected to occur during 2009. For example, by the end of 2009 what process/business activities will be integrated and shared by the two Divisions?

d) Are all of the costs and savings set out in Table #1 (page 3) related to 2009. If not please re-do the table including just 2009 costs and savings.

e) With respect to Table #1, please provide greater details regarding the transition costs of $4.3 M.

Response

a) Both these amounts are for 2009; however, none of the $4.7M in capital savings are attributable to PowerStream (see Staff-5) and the $2.4M of net OM&A costs are divisible between PowerStream and Barrie. (See Staff-35).

b) Please see the response to Staff- 5.

c) The following table describes the estimated degree of integration at the end of the first quarter of 2009 and the forecast degree of integration at the end of the year.

Table VECC 6-1: 2009 MergeCo Integration Status

Functional Area	Estimated % Integration March 31, 2009	Forecast % Integration at end of 2009
Human Resources and Health & Safety	30%	60%
Finance	20%	60%
Customer Service	20%	60%
Information Services and Facilities	15%	70%
Engineering	10%	50%
Operations	20%	40%
Corporate & Communications	60%	70%
Executive Support & Metering	30%	60%
Procurement and Fleet	10%	50%
Regulatory and CDM	35%	60%

d) All of the cost and savings shown are expected to occur in 2009.

e) Please see Staff - 35.

Vulnerable Energy Consumers Coalition – Interrogatory #7

RATE BASE AND CAPITAL SPENDING

Reference: Exhibit B1/Tab 1/Schedule 1, page 2

Question:

a) Please update Table #1 for the 2008 actual values.

Response

a) Please refer to EP - 2.

Vulnerable Energy Consumers Coalition – Interrogatory #8

Reference: Exhibit B1/Tab 2/Schedule 1, page 2

Question:

a) Has PowerStream prepared and/or is PowerStream in the process of preparing a five year capital plan for 2009-2013 and two year capital budget for 2009-2010?

b) If the response to part (b) is yes, please indicate the current status and provide copies, if either are effectively completed (i.e., has been forwarded to either PowerStream's full Board or a sub-committee of the Board).

Response

a) Please refer to EP-3(a) with respect to PowerStream's next Five Year Plan.

For rate application purposes only, PowerStream prepared a detailed two year capital budget. As part of PowerStream's normal capital investment process, the detailed 2010 capital budget will not be completed until Q4 2009.

b) Please see response (a).

Vulnerable Energy Consumers Coalition – Interrogatory #9

Reference: Exhibit B1/Tab 2/Schedule 1, pages 1 & 4

Question:

a) **Per page 1 (lines 3-4), please provide the measures and expected outcomes for 2008 associated with each of the goals set out on page 4. Please indicate whether or not each of the 2008 goals were met.**

b) **Is the Distribution System Planning Report a separate document from the Five Year Capital Plan? If so, please provide a copy of the Distribution System Planning Report that informed the proposed capital spending included in the Application. Also, if a more recent/updated version of the Distribution System Planning Report has been prepared, please provide it as well.**

Response

a) This information will be filed in confidence in accordance with the Board's Rules of Practice and Procedure and its Practice Directions on Confidential Filings.

b) The Distribution System Planning Report (DSPR) is a separate document from the Five Year Capital Plan and the most current version of the DSPR is attached as Schedule VECC 9-1.

Vulnerable Energy Consumers Coalition – Interrogatory #10

Reference: Exhibit B1/Tab 2/Schedule 1, pages 15-16

Question:

a) Please provide copies of the Phase 1 and Phase 2 Asset Condition Reports.

b) Please also provide a copy of the Phase 3 Asset Condition Report, if completed. If not completed, please indicate when PowerStream expects the report to be completed.

c) How frequently does PowerStream plan on redoing its Asset Condition Reports?

Response

a) Refer to the attached Schedule VECC 10-1, a copy of PowerStream's Phase 1, Phase 2 and Phase 3 Asset Condition Assessment programs.

b) See a)

c) PowerStream plans on updating its Asset Condition Assessment model annually.

Vulnerable Energy Consumers Coalition – Interrogatory #11

Reference: Exhibit B1/Tab 2/Schedule 1, pages 18 and 26-27

Question:

a) With respect to the budget and capital planning process outlined on these pages please confirm whether the capital expenditure envelop is:

- **An input to the process such that revenues and associate rate levels are an output, or**
- **An output of the process wherein assumptions are made regarding rate levels and revenues.**

If the former, please indicate if/how customer bill impact considerations are taken into account in the budget process.

If the later, what input assumptions are made regarding future rate levels in the development of the capital envelop?

b) The description of the capital budget process on pages 26-27 only appears to deal with "base capital requirements" – as defined in Figure 5. How are the capital requirements for Special Projects (per pages 17 & 19) factored into the budgeting process?

c) With respect to PowerStream's preparation of the 2009 Budget and Capital Plan please indicate the following:

- **What was the original base capital envelope provided by Corporate Finance (per page 26) and what was the associated rate increase underlying this envelop.**

- **How does the spending level in the proposed capital budget for 2009 compare to the original base capital envelop?**

- **Does the 2009 proposed capital spending budget contain any projects that are not considered Non-Discretionary or Discretionary – Urgency One? If yes, please provide a schedule that sets out these projects and the associated 2009 capital spending for each.**

Response

a) The capital expenditure envelope is an input to the process of budget preparation. Customer bill impacts are examined in detail in a rebasing year. In other years when revenue is capped by the IRM formula, the level of capital spending does not impact customer bills.

b) Special projects are unique in nature due to magnitude or need. They are taken through a different evaluation process than base capital projects to determine their relative priority and the need to be included in the current budget year. This evaluation process involves a business case analysis on all projects of a material magnitude.

c) First bullet:

The original net capital envelope provided by Corporate Finance for 2009 was $85.2M and the associated rate increase underlying this envelope was 7% including capital additions from previous years.

Second bullet:

There is no change in the proposed capital budget for 2009 as compared to the original base capital envelope.

Third bullet:

With respect to Urgency One see Staff 4.

Vulnerable Energy Consumers Coalition – Interrogatory #12

Reference: Exhibit B1/Tab 3/Schedule 1, pages 1 and 7-12

Question:

a) Please confirm that the new burden rates were used for 2008 such that the 2008 and 2009 capital spending amounts are reported on a comparable basis.

b) Overall, did the new burden rates tend to increase or decrease reported capital spending levels? If possible, please provide an indication as to the percentage impact the change in burden rate has on reported capital spending in 2008 and 2009.

Response

a) The 2008 capital budget was prepared using the old burden rates. The 2009 capital budget was prepared using the new burden rates.

b) PowerStream conducted a review and update of its burden rates in 2007. Please see the response to Staff-37 for the "Payroll Burden and Overhead Rates Review". The purpose of this review was to provide rates that better reflected costs. There were a few minor changes in methodology, namely:

- Payroll burden applied only to regular time and not to overtime
- No application of Engineering burden on material issues

PowerStream has not aggregated the information that would be needed to answer this question and it is not feasible to do so in the Interrogatory process. It seems likely that the increase in payroll burden and vehicle charges would be largely offset by the net reduction in the Engineering burden, and the resulting impact small.

It is not possible to provide an indication as to the percentage impact the change in burden rates has on reported capital spending in 2008 and 2009. However overall the new burden rates did not likely have a significant effect on reported capital spending as the increase in payroll burden and vehicle charges would be largely offset by the net reduction in the Engineering burden.

Vulnerable Energy Consumers Coalition – Interrogatory #13

Reference: Exhibit B1/Tab 3/Schedule 1, pages 5-6

Question:

a) Please indicate where PowerStream's amortization rates differ from those set by the OEB and what the differences are.

Response

a) The amortization rates used were the same as those set by OEB.

Vulnerable Energy Consumers Coalition – Interrogatory #14

Reference: Exhibit B1/Tab 4/Schedule 1, page 1

Question:

a) This section uses the terms "capital spending" and "capital additions" interchangeably. Please confirm whether for the 2006-2009 period all capital spending is declared in in-service the same year it is reported as spent. If not, please provide a continuity schedule that reconciles capital spending and capital in-service additions over this period.

Response

a) No, not all capital spending is declared in-service the same year it is reported as spent. For large projects the capital spending can span several years in which it is recognized as work in progress. The asset is recognized in rate base in the year it goes into service. For the continuity schedule please refer to EP-6(c).

Vulnerable Energy Consumers Coalition – Interrogatory #15

Reference: Exhibit B1/Tab 4/Schedule 2, page 2

Question:

a) Please provide a schedule that, for 2009, breaks the spending for each line item down into: i) Non-Discretionary; ii) Discretionary – Urgency One and iii) Discretionary – Urgency Two.

b) With respect to the response to part (a), please explain why the "Non-Discretionary" portion of each line item is considered to be such.

c) With respect to the response to part (a), please explain why the "Discretionary-Urgency One" portion of each line item must be completed in 2009.

Response

Please see Table VECC 15a for the 2009 budget breakdown of Non- Discretionary and Discretionary – Urgency One type projects. During the early stages of 2009 Budget preparation, projects identified as Discretionary – Urgency Two were deferred to the next (2010) budget year.

Table VECC 15a: Project by Category 2009 Expenditure Type

Table 2: Project by Category 2009 Expenditure Type

PROJECT DESCRIPTION	2009	Expenditure Type
1. Sustainment Capital		
1a. Pole or Line Replacements / Upgrades	4,404	Discretionary - Urgency 1
1b. Transformer Station Enhancements / Upgrades	3,232	Discretionary - Urgency 1
1c. Asset Condition Assessment Program	4,398	Discretionary - Urgency 1
1d. Distribution System Voltage Conversions	3,488	Discretionary - Urgency 1
1e. Switchgear Replacements / Upgrades / Refurbishments	1,298	Discretionary - Urgency 1
1f. Cable Replacement	332	Discretionary - Urgency 1
1g. Load Transfers From Other LDC's	0	Non-Discretionary
1h. Distribution Transformer Enhancements / Upgrades / Refurbishment	281	Discretionary - Urgency 1
1i. Load Interrupter Switch Replacement	408	Discretionary - Urgency 1
1j. Distributor Station Enhancements / Upgrades	472	Discretionary - Urgency 1
1k. Unforeseen Capital Projects	414	Mixed
Total Sustainment Capital	19,618	
2. Development Capital		
2a. Transformer Stations - Additional Capacity	18,771	Discretionary - Urgency 1
2b. Residential Subdivisions	4,016	Non-Discretionary
2c. Distribution System Plant Re-Location	4,868	Non-Discretionary
2d. New Commercial Services	181	Non-Discretionary
2e. Distribution Stations - Additional Capacity	0	Discretionary
2f. New Overhead or Underground Lines	8,742	Discretionary - Urgency 1
2g. Unforeseen Capital Projects	414	Mixed
Total Development Capital	41,019	
3. Operations Capital		
3a. System Operation Automation	1,016	Discretionary - Urgency 1
3b. Unplanned Equipment Replacement	1,878	Discretionary - Urgency 1
3c. Suite-Metering Costs	1,098	Non-Discretionary
3d. Fleet	597	Discretionary - Urgency 1
3e. Wholesale Meters	198	Non-Discretionary
3f. Tools	310	Discretionary - Urgency 1
3g. Smart Grid Program	608	Discretionary - Urgency 1
3h. Meter Re-Verification and Replacement Program	390	Non-Discretionary
3i. Asset Condition Assessment Model Development	28	Discretionary - Urgency 1
3j. Geographic Information System	101	Discretionary - Urgency 1
3k. Conservation & Demand Management - Smart Meter Pilot	0	Non-Discretionary
3l. System Control Room	0	Discretionary
3m. Storm Damage To Distribution System	617	Non-Discretionary
3n. Conservation & Demand Management - Load Control Devices	0	Non-Discretionary
Total Operations Capital	7,674	
4. Other Miscellaneous Capital		
4a. Information Technology Enhancements	882	Discretionary - Urgency 1
4b. Customer Information System Enhancements	1,351	Discretionary - Urgency 1
4c. Financial System Enhancements	308	Discretionary - Urgency 1
4d. New Computer Equipment / Replacement	800	Discretionary - Urgency 1
4e. New Head Office	381	Discretionary - Urgency 1
4f. Software Purchase	187	Discretionary - Urgency 1
Total Other Miscellaneous Capital	3,955	
5. Total Smart Meters Program	12,975	Non-Discretionary
Total Capital Expenditures	85,241	

b) All line items described as "Non-Discretionary" are made up entirely of projects that are driven by external agencies. Line items that are described as "Mixed" depend on the specific nature of the project and since these projects are unplanned they cannot be pre-classified.

c) As per PowerStream's capital investment process described in Exhibit B1-2-1, projects classified as Urgency 1 (see definition on page 25 of the referenced exhibit) must be done in the budget year. Refer to response Staff-4.

Vulnerable Energy Consumers Coalition – Interrogatory #16

Reference: Exhibit B1/Tab 4/Schedule 2, page 5

Question:

a) What are the current loading levels on the PowerStream's ten transformer stations and when does PowerStream expect that additional in-service capacity will be required to address capacity constraints at these stations?

Response

a) Current peak loading levels achieved in 2008 are as follows:

Vaughan TS1	149MW
Vaughan TS1E	85MW
Vaughan TS2	138MW
Vaughan TS3	141MW
Richmond Hill TS 1	146MW
Richmond Hill TS 2	92MW
Markham TS1	82MW
Markham TS2	82MW
Markham TS3	80MW
Markham TS4	72MW

It is anticipated that additional service capacity may be required in 2012. See Exhibit B1-6-1 Line 269 to 272.

Vulnerable Energy Consumers Coalition – Interrogatory #17

Reference: Exhibit B1/Tab 4/Schedule 2, pages 7-8

Question:

a) Apart from the areas listed on page 8 are there other areas of the PowerStream Division' service area that are currently operating at voltages below 27.6 kV. If yes, what are PowerStream's longer term plans for their conversion and why were the listed areas given priority?

Response

a) There are other areas in PowerStream's service territory that are currently operating at a voltage below 27.6 kV.

Areas serviced by the Elder Mills, Rainbow and Maple municipal stations, in addition to those areas cited in Exhibit B1- 4- 2, Page 8, are candidates for conversion. The three areas cited in Exhibit B1- 4- 2, Page 8, were selected as Urgency One based on capacity, reliability, aging assets, operating switching limitations and maintenance issues.

Vulnerable Energy Consumers Coalition – Interrogatory #18

Reference: Exhibit B1/Tab 4/Schedule 2, pages 10-11

Question:

a) The 2009 budget for Load Transfers (Item 1 g) is zero. Is this because all work related to load transfers will be completed by 2008? If not, please explain.

Response

a) At the time the Application was prepared it was expected that all load transfers would be complete by the end of 2008. The actual result is that some load transfers will not be completed until 2009, the expense of which is carried over from 2008 and will not impact the 2009 revenue requirement as filed

Vulnerable Energy Consumers Coalition – Interrogatory #19

Reference: Exhibit B1/Tab 4/Schedule 2, pages 12 and 15-16

Question:

a) Please identify those distribution stations that are currently exceeding or approaching (by 2010) acceptable loading levels. In the context of this response please explain what PowerStream considers to be an acceptable "loading level".

Response

a) All PowerStream's stations are expected to be at acceptable loading limits before new capacity is deemed to be required. From a load forecast perspective, PowerStream assumes that it will reconfigure the distribution system feeders to use all available station capacity before a new station is required.

PowerStream considers an acceptable "loading level" on a transformer to be 10-day Limited Time Rating (LTR) under an N-1 contingency situation (i.e. loss of a single element).

Vulnerable Energy Consumers Coalition – Interrogatory #20

Question:

Reference: Exhibit B1/Tab 4/Schedule 2, pages 13-14

a) Please provide the load forecast (page 13, lines 296-297) underlying the development capital spending proposed for 2009.

b) Please provide the actual loads for 2007 and 2008 on comparable basis to those in the forecast from part (a).

c) The discussion on page 13 (lines 303-308) suggests that not all capital spending comes "in-service" the year it is spent. Please reconcile this discussion with the response provided to Question #14.

Response

a) Please see page 8 of the Transformer Station Needs Assessment Study filed in response to SEC 17(d).

b) 2007 Actual – Coincident Peak Demand – 1,519 MW
2008 Actual - Coincident Peak Demand – 1,444 MW

c) The new transformer station as cited in lines 303-308 will be recognized in the rate base in the year the project goes into service, in this case 2009.

Vulnerable Energy Consumers Coalition – Interrogatory #21

Question:

Reference: Exhibit B1/Tab 4/Schedule 2, page 19

a) Please provide greater details regarding PowerStream's Suite Metering program.

- **Provide the 2008 and 2009 suite metering costs and # of units.**
- **Indicate the breakdown between condominiums (covered under existing regulations) and rental units**
- **Does PowerStream have a sub-metering affiliate/related party? If so provide details.**

b) Is the Suite Metering program considered a CDM program? If so, please provide the results of the TRC test and supporting assumptions. If not, please provide the business case supporting PowerStream undertaking the program.

c) Please explain how the recent Compliance Bulletin issued by the OEB (Bulletin 200901- Installation of Sub-Metering Systems in Residential Complexes) impacts on this program.

Response

a)
- 2008 program costs were $ 1.7M for 2,500 units. 2009 program costs are forecast at $ 1.1M for 1,600 units.
- These installations were/will be in condominiums. PowerStream does not install individual suite metering in rental properties.
- No.

b) The Suite Metering Program is not considered a CDM program. Please see response to SSMWG -1.

c) OEB Compliance Bulletin # 200901 does not apply to PowerStream's suite metering program as PowerStream does not install individual suite meters in residential complexes as defined in the *Residential Tenancies Act, 2006*.

Vulnerable Energy Consumers Coalition – Interrogatory #22

Question:

Reference: Exhibit B1/Tab 4/Schedule 2, page 20

a) Please describe what the Smart Grid funding requested for 2009 ($505,000) is for.

b) Does PowerStream plan on completing its Smart Grid Strategy prior to making any of the capital investments discussed at lines 491-496?

c) Does PowerStream plan on preparing a business case to demonstrate the cost-effectiveness of its Smart Grid Strategy? If yes, when will this be completed?

Response

a) The Smart Grid funding in 2009 is based on the installation of fault detectors that pinpoint the location of an electrical fault to the operators as soon as the fault happens and the installation of intelligent fault interrupters which limit the level of electrical current when a fault occurs.

b) The development of a Smart Grid strategy is complex and has many facets. As PowerStream formulates this strategy, limited investments are proposed in order to learn more about the technologies. The projects described in (a) above are expected to be included as part of the final strategy. The Smart Grid strategy is currently under review in light of the Province's announcement of the Green Energy Act (GEA) to ensure consistency and alignment between the proposed strategy and the new Act. Any Smart Grid expenditures in 2009 will be consistent with the proposed smart grid strategy and the government's GEA.

c) We anticipate that strategy will be brought to PowerStream's Board of Directors later in 2009.

Vulnerable Energy Consumers Coalition – Interrogatory #23

Question:

Reference: Exhibit B1/Tab 5/Schedule 4, pages 9-13

a) The discussion at page 9, lines 190-195 indicates that PowerStream discarded the Buttonville Expansion option prior to an assessment of costs or any of the other factors listed on page 10. Please explain why it is so important for PowerStream to own and operate its own transformer stations that this option would be discarded prior to any such assessment.

b) Please provide a status update on the schedule for Markham TS#4. Is it still expected to be fully in-service by December 2009?

Response:

a) In the late 1980's, Ontario Hydro adopted a policy stating that utilities that have built their own transformer station(s) have full responsibility for providing future capacity additions to supply the needs of their particular service area. PowerStream's predecessor utilities all built their transformer stations according to this understanding. A key benefit for LDCs owning their own stations was the cost advantage that benefited the LDC ratepayer.

In 1998, with the advent of Bill 35, one of PowerStream's predecessor utilities reviewed the benefits of station ownership and reaffirmed that the difference between the cost of paying the HONI pool transformation rate for a HONI owned facility versus and the LDC's cost of owning and maintaining transformer stations presented considerable advantage in reduction in cost to the LDC ratepayer. This position on transformer station ownership was carried over when PowerStream was formed.

The Buttonville Station option was discarded based on our ownership requirements. Hydro One has been approached in the past to ascertain their willingness to sell PowerStream its Buttonville facilities however they have indicated that they were not interested in selling these assets. Ownership of our own facility was a key PowerStream position for capacity expansion as it provided benefits such as:

- reduced transmission tariffs benefiting the ratepayer
- improved operating control of the distribution system
- the elimination of any licensed territory issues
- the continuance of past precedents and previous agreements

b) The schedule for Markham TS#4 has a December 15, 2009 in-service date. The current status is that the station has received Class EA approval, Conditional Site Plan Approval from the Town of Markham and contract has been awarded for the Civil and Electrical work to achieve the December 15, 2009 in-service date. Hydro One have indicated that they can meet a December 15, 2009 in-service date for the station for their transmission connection work.

Vulnerable Energy Consumers Coalition – Interrogatory #24

Question:

Reference: Exhibit B1/Tab 7/Schedule 1, pages 4-5

a) Table 4 indicates that fixed assets at cost have increased by $189.6 M from 2006 Actual to 2009 Forecast. Capital spending over the same period is reported as $219.1 M (per Exhibit B1/Tab 4/Schedule 2, page 2). Please explain why the two values don't reconcile.

Response

a) The 3 year capital addition results from Exhibit B1-7–1, Table 4 are net of retirement and disposals. In other words, using the asset closing balances and calculating the changes does not simply result in true capital additions due to the impact from disposals.

Refer to Exhibit B1-7-1, Table 2 which shows the separation between additions and retirements.

The actual 3 years rate base additions total $221.8M. Compared to the capital budget additions per Exhibit B1-4-2, Table 2 totaling $219.1M, the difference is only $2.7M.

The two values do not reconcile because of work in process changes which create timing differences for asset rate base recognition.

Vulnerable Energy Consumers Coalition – Interrogatory #25

Question:

Reference: Exhibit B1/Tab 7/Schedule 2, page 3

a) Please provide an expanded continuity schedule for net fixed assets that shows annual additions and depreciation separately.

b) Please explain the $537,000 of Retirements shown for both 2008 and 2009.

Response

a) Please see Schedule VECC 25-1.

b) The $537,000 of retirements are the net book value of vehicle disposals.

Vulnerable Energy Consumers Coalition – Interrogatory #26

Question:

Reference: Exhibit B2/Tab 1/Schedule 2, page 2

a) This page makes reference to an October 2008 Navigant Consulting Report prepared for the OEB. However, Exhibit A1/Tab 4/Schedule 1, page 1 makes reference to a November 2008 Navigant Consulting Report prepared for the IESO. Please clarify if there are two reports or whether a correction is required to the filing.

b) If there is a separate Navigant Report that has been prepared for the IESO on which PowerStream's Application is relying, please provide a copy.

Response

a) Both exhibits make reference to the same report. The reference on lines 6-7 in Exhibit A1-4-1, page 1 is to the November 2008 IESO Outlook report. This reference should be read as "Updated the cost of power based on Ontario Wholesale Electricity Market Price Forecast report prepared by Navigant Consulting". This report was presented to the OEB on October 15, 2008. This is the same report referenced in Exhibit B2-1-2, page 2.

b) There is no separate report.

Vulnerable Energy Consumers Coalition – Interrogatory #27

Question:

Reference: Exhibit B2/Tab 1/Schedule 3, page 2

a) At Exhibit B1/Tab 7/Schedule 1, page 1 the $459,051,000 Net Fixed Asset value for 2009 is defined as the year-end value. Why is this value used in determining rate base for 2009 as opposed to the average of 2009 opening and closing balances for net fixed assets?

Response

a) The values of $459,051,000 in Exhibit B2-1-3, page 2 is average of 2009 opening and closing balances for net fixed assets. This value was used for the rate base calculation.

The second note to Table 1 in Exhibit B1-7-1 is incorrect. It should read "2006 Actual, 2007 Actual, 2008 Bridge Year and 2009 Test Year represent average opening and closing balances for net fixed assets"

Vulnerable Energy Consumers Coalition – Interrogatory #28

LOAD FORECAST/THROUGHPUT REVENUE

Question:

Reference: Exhibit C1/Tab 1/Schedule 1, page 1

a) Please provide a schedule that sets out the determination of the 2009 revenue at current rates for each class, showing the rates used and the billing determinants.

b) If different from part (a) please provide a schedule that sets out the 2009 revenues at current rates by customer class (including rates and billing determinants by class) determined as follows:

- **Exclude the LV rate adder used to recover Hydro One Networks' LV costs**
- **Account for the lower revenues due to the transformer ownership allowance discount.**

Response

a) Please see Schedule VECC 28-1.

b) The rates provided in a) exclude LV rate adder. For ease of reference the monthly rates and charges are reproduced from the Schedule VECC 28-1 to the table below:

Table VECC 28-1: Monthly Rates and Charges

MONTHLY RATES AND CHARGES		2008 for Distribution Revenue calculation	2008 Rates Tariff	difference	note
Residential					
Service Charge	$	12.02	13.23	1.21	SM adder
Distribution Volumetric Rate	$/kWh	0.0129	0.0131	0.0002	LV charge
General Service Less Than 50 kW					
Service Charge	$	28.70	29.91	1.21	SM adder
Distribution Volumetric Rate	$/kWh	0.0112	0.0114	0.0002	LV charge
General Service 50 to 4,999 kW					
Service Charge	$	301.73	302.94	1.21	SM adder
Distribution Volumetric Rate	$/kW	2.2713	2.3627	0.0914	LV charge
Large Use					
Service Charge	$	8,978.09	8897.3	(80.79)	SM adder
Distribution Volumetric Rate	$/kW	1.1989	1.3036	0.1047	LV charge
General Service 50 to 4,999 kW – Time of Use					
Service Charge	$	3,313.25	3314.46	1.21	SM adder
Distribution Volumetric Rate	$/kW	1.5576	1.6590	0.1014	LV charge
Unmetered Scattered Load					
Service Charge	$	14.35	14.35	0.00	
Distribution Volumetric Rate	$/kWh	0.0111	0.0114	0.0003	LV charge
Regulatory Asset Recovery	$/kWh	0			
Sentinel Lighting					
Service Charge	$	2.01	2.01	0.00	
Distribution Volumetric Rate	$/kW	6.0151	6.0842	0.0691	LV charge
Regulatory Asset Recovery	$/kW	0			
Street Lighting					
Service Charge	$	0.84	0.84	0.00	
Distribution Volumetric Rate	$/kW	3.3980	3.4686	0.0706	LV charge

PowerStream accounts for the lower revenues due to the transformer ownership allowance discount at the total level as opposed to adjusting rates within each rate class. The end result would be the same under either methodology.

The revenue at current rates is reduced by $2,551,097 of transformer ownership allowance, as shown in Exhibit C1-1-4, Table 1.

Vulnerable Energy Consumers Coalition – Interrogatory #29

Question:

Reference: Exhibit C1/Tab 1/Schedule 1, page 2

a) Please provide a revised version of Table 2 where 2006, 2007 and 2008 values are weather normalized.

b) For 2008 the kWh sales decrease slightly from 2007 levels. However, the kW demand for 2008 is higher. Please explain why for 2009 the kWh sales are higher than for 2008 but the kW demand goes down.

Response

a) **Table VECC 29-1: Consumption, Demand and Customers (Weather Normalized)**

	2006 OEB Approved	2006 Actual Normalized	2007 Actual Normalized	2008 Actual Normalized	2009 Test Year
Consumption, KWH	6,425,946,366	6,741,195,254	6,788,085,616	6,906,362,748	6,829,307,310
Demand, KW	9,415,073	10,157,880	10,400,129	10,558,964	10,400,971
Customer Count		228,666	236,377	243,780	251,638
Variance Analysis (units)	2006 vs. 2006 OEB appr.	2007 vs. 2006	2008 vs. 2007	2009 vs. 2008	
Consumption, KWH	315,248,888	46,890,362	118,277,131	-77,055,438	
Demand, KW	742,807	242,250	158,835	-157,993	
Customer Count		7,711	7,403	7,858	
Variance Analysis (%)	2006 vs. 2006 OEB appr.	2007 vs. 2006	2008 vs. 2007	2009 vs. 2008	
Consumption, KWH	4.9%	0.7%	1.7%	-1.1%	
Demand, KW	7.9%	2.4%	1.5%	-1.5%	
Customer Count		3.4%	3.1%	3.2%	

b) The 2008 actual sales reported in Exhibit C1-1-1, Table 2 are not weather-normalized. As shown in part a), when 2009 test year consumption and demand is compared to 2008 actual normalized results, the variance is a reduction in 2009 for both consumption and demand.

Vulnerable Energy Consumers Coalition – Interrogatory #30

Question:

Reference: Exhibit C1/Tab 1/Schedule 2, page 1

a) When was the current load forecasting model used by PowerStream developed and first used for budgeting purposes?

b) Please provide the load forecast(s) that was used in preparation of the approved 2008-2009 Capital Plan and the related annual budgets (per Exhibit B1/Tab 2/Schedule 1, pages 2 & 11).

c) Please contrast PowerStream's current load forecast with the load forecasts used for purposes of preparing the Capital Plan and Budget.

Response

a) The current load forecasting model was developed by PowerStream in 2007. The model was developed in order to address the fact that PowerStream realized it did not have a rigorous load forecasting methodology for revenue calculation purposes. The results of the empirical work described in Exhibit C1-1-2 were first used by PowerStream in the fall of 2007 to establish the distribution revenue budget for 2008. The current model estimates energy purchases in aggregate and then PowerStream makes the appropriate adjustments to derive net sales. These purchases are then allocated to rate classes based on historical consumption. PowerStream anticipates estimating distribution sales per customer class as sufficient data becomes available for regression analysis at that disaggregated level.

b) Please see page 8 of the Transformer station Needs Assessment Study filed in response to SEC 17(d).

c) The objective of the revenue load forecast is to ensure that under normal weather conditions PowerStream is able to recover its revenue requirement from distribution base rates. In contrast, the demand forecast prepared for capital planning and budget purposes targets system demand capacity to ensure assets are in place that will supply peak demand levels as required.

Vulnerable Energy Consumers Coalition – Interrogatory #31

Question:

Reference: Exhibit C1/Tab 1/Schedule 2, pages 4-14

a) Please explain more fully why Model #4 is preferred over #5.

b) Please provide the equivalent of Table 7 (page 9) based on Model #5.

c) Please provide the GDP forecasts from the major financial institutions relied on to develop the forecast GDP values used for the load forecast and show how the GDP values set out in Table 8 were derived.

d) Please prepare a forecast of purchased energy for 2009 based on Model #5.

Response

a) Model 5 was discarded after detailed analysis of the regression statistics. The customer count variable, even though suggested by model 5, was rejected as a variable that would enhance the load forecast results. The variable displayed "too much multicollinearity" with the GDP independent variable (i.e. the independents are highly inter-correlated): the more the multicollinearity, the lower the tolerance, the more the standard error of the regression coefficients. When tolerance is close to 0 there is high multicollinearity of that variable with other independents as shown in the table below. As a rule of thumb, if tolerance is less than 0.20, a problem with multicollinearity is indicated.

Table VECC 31-1: Model 5 Collinearity Statistics

Model		Collinearity Statistics	
		Tolerance	VIF
6	(Constant)		
	GDP	0.044	22.899
	CDD	0.492	2.032
	HDD	0.488	2.049
	Hours	0.981	1.019
	Customer_Count	0.044	22.929

Model 4 was preferred over Model 5 because:

- High linear dependence of GDP index and customer count variables, which makes b and beta coefficients unstable and increase the standard error of regression coefficients in Model 5

- Qualitative analysis – for simplicity, only one variable should be included in the regression equation for the purpose of explaining the trend/growth effect; both variables – GDP index and customer count (Model 5) – provide the same information, i.e. they are redundant

b) As specified by IR# 31a), Model 5 is not an appropriate load forecast tool for PowerStream.

Table VECC 31-2: Model 5 Regression Results

Dependent Variable: Monthly Energy Purchases Form: Multiple Regression Sample: 01/1998 - 03/2008 Included observations: 123			
Variable	**Coefficient**	**t-Statistics**	**Sig.**
(Constant)	-286,770,816	-6.58	0.000
Real GDP	3,684,627	6.01	0.000
CDD	970,112	28.58	0.000
HDD	93,418	13.94	0.000
Monthly Peak Hours	431,624	5.77	0.000
Customer Count	827	3.94	
R-squared	96%	**Mean dependent variable**	525,355,792
Standard Error of regression	13,330,855	**S.D. dependent variable**	70,573,318
F-test	660.441	**Durbin-Watson statistics**	1.757

c) For details on the individual GDP forecasts from the major financial institutions see Schedule VECC 31-1.

The monthly GDP index was derived from the annual GDP growth rate which is publicly available on the major financial institutions' websites. Since the GDP growth rate is annualized, PowerStream assumed the GDP grows evenly by month in deriving the monthly variable. For example, if the annual GDP growth rate is 2.1%, then monthly growth rate X would be roughly calculated by dividing 2.1% by 12 (i.e. monthly allocation of 0.175%). This derived monthly increment of the GDP growth rate is used to calculate GDP index for each month based on historical data. 2007 is assigned a value of 100 and then monthly allocation is applied for each month going forward. For example, if January 2009 real GDP index is 133.8 and 2009 monthly averaged allocation is -0.114, then February 2009 GDP will be 133.6.

Table VECC 31-3: Calculated monthly GDP index

Year	BMO	Scotia	RBC	TD	CIBC	NBC	Average	Stat Canada	*Analysis Annual AVG*	*Monthly Allocation*	Index
1998								4.7	*4.7*	*0.392*	***104.7***
1999								7.7	*7.7*	*0.642*	***112.4***
2000								6.1	*6.1*	*0.508*	***118.5***
2001								1.4	*1.4*	*0.117*	***119.9***
2002								2.9	*2.9*	*0.242*	***122.8***
2003								1.6	*1.6*	*0.133*	***124.4***
2004								2.7	*2.7*	*0.225*	***127.1***
2005								2.8	*2.8*	*0.233*	***129.9***
2006								1.9	*1.9*	*0.158*	***131.8***
2007								2.1	*2.1*	*0.175*	***133.9***
2008F	*-0.2*	*-0.2*	*-0.2*	*0.3*	*-0.1*	*0.1*	-0.1	*no data*	*-0.1*	*-0.004*	***133.9***
2009F	*-2.3*	*-2*	*-1.4*	*-1.8*	*0.1*	*-0.8*	-1.4	*no data*	*-1.4*	*-0.114*	***132.5***

d) Model 5 cannot be used for the purpose of the forecast. Please refer to IR 31a). Once there is a presence of multi-collinearity, the regression individual b and Beta coefficients are inflated and unstable and the accuracy of the model is diminished.

Vulnerable Energy Consumers Coalition – Interrogatory #32

Question:

Reference: Exhibit C1/Tab 1/Schedule 2, pages 14-17

a) The data 1998-2008 data used develop PowerStream's load forecasting model will reflect CDM activities undertaken by its customer until the end of 2008.

- **Does PowerStream agree that this results in the estimated model including some trend effects for CDM? If not, why not?**

- **Since the model includes 2008 use already, why is it necessary to include a separate adjustment for the 2008 impact of the OPA's CDM programs?**

b) Please confirm that the OPA energy conservation savings in Table 2 are taken from the OPA's IPSP Application, Exhibit D/Tab 4/Schedule 1/Attachement 1, page 5 – Table 6. If not, what is the source?

c) The footnote to the OPA's Table 6 (per part (b)) states that conservation savings are measured at the "generator".

- **What loss assumption has PowerStream used in its analysis of determining the impact at the customer level?**

- **Please explain where in PowerStream's analysis these losses were taken into account.**

Response

a) Yes, the results will include some trend effects for CDM as customers become more conscious of conservation over time. However, the trend results do not capture the impact of new or incremental CDM expenditures by PowerStream and province-wide CDM initiatives which will affect consumption more significantly that what is captured in the historical trend.

There was no separate adjustment for the 2008 impact of the OPA's CDM program applied to 2008 load. Actual 2008 values were reported. Refer to Table 15 on Exhibit C1-1-2, page 17 for the CDM adjustment to the forecast load.

b) OPA proposed GTA energy conservation savings are taken from the OPA's IPSP Application (EB-2007-0707), Exhibit 2-4-1, Attachment 4, page 4 – Table 5 and page 5 – Table 6.

c) The total distribution loss factor PowerStream used in its analysis of determining the impact at the customer level is outlined is 1.0330.

Vulnerable Energy Consumers Coalition – Interrogatory #33

Question:

Reference: Exhibit C1/Tab 1/Schedule 2, page 19

a) Given that past and future customer count growth may vary by class why is it reasonable to assume that the average kWh allocation over the 2006-2008 period is a reasonable forecast of what the allocation of 2009 kWh sales will be?

b) Please provide the supporting data used to determine Table 16. Please confirm whether the kWh values used were actual or weather normalized values.

c) Please provide a schedule that sets out the historical sales by customer class from 2002 to 2008. If not provided in response to part (b), please also include in the schedule the normalized sales by customer class for 2006-2008. For customer classes that are demand billed please include both kWh and kW.

Response

a) Average kWh allocation over the 2006-2008 period was the most reasonable and defendable indicator available when forecasting one year out.

b) Actual kWhs were used to derive historic kWh allocation by rate class.

Table VECC 33-1: Consumption and Demand by Customer Class (Actual)

	2006 Actual		2007 Actual		2008 Actual	
Rate Class	kWh	kW	kWh	kW	kWh	kW
Residential	1,988,486,894		2,039,498,572		2,065,819,367	
GS<50	776,973,164		796,189,248		809,934,026	
GS>50	3,561,122,920	9,379,753	3,854,553,131	10,102,296	3,794,823,425	10,125,964
Time of use	49,136,466	77,885	58,792,355	95,040	60,456,799	95,946
Large Use	283,255,705	539,544	31,986,565	86,879	30,339,590	80,893
USL	10,270,011		8,378,782		8,654,016	
Sentinel Lighting	443,695	1,196	469,111	1,243	530,185	1,356
Street Lighting	40,635,772	112,985	42,585,750	118,262	44,133,043	139,797
Total	**6,710,324,626**	**10,111,363**	**6,832,453,515**	**10,403,720**	**6,814,690,452**	**10,443,956**

Table VECC 33-2: Allocation of Average kWh by Customer Class

Year	2006	2007	2008	3-year average
Residential	29.46%	29.59%	30.31%	**29.79%**
GS <50 kW	11.63%	11.68%	11.97%	**11.76%**
USL	0.11%	0.12%	0.13%	**0.12%**
GS>50 kW	56.98%	56.63%	55.63%	**56.41%**
TOU	0.74%	0.87%	0.88%	**0.83%**
Large User	0.47%	0.47%	0.44%	**0.46%**
Street Lighting	0.61%	0.63%	0.63%	**0.62%**
Sentinel	0.01%	0.01%	0.01%	**0.01%**
	100.00%	100.00%	100.00%	100.00%

c) Historic consumption/demand data by rate class prior to 2006 (i.e. prior to PowerStream merger and Aurora acquisition) is not sufficiently accurate and reliable for load forecasting or comparative purposes and therefore was collected and used.

The normalized sales by customer class for 2006-2008 are outlined in the table below.

Table VECC 33-3: Historical Sales by Customer Class for 2006-2008 (Normalized)

Rate Class	2006 Normalized		2007 Normalized		2008 Normalized	
	kWh	kW	kWh	kW	kWh	kW
Residential	1,997,634,862		2,009,723,587		2,107,000,812	
GS<50	780,547,603		793,823,016		828,281,828	
GS>50	3,577,505,749	9,422,904	3,842,363,103	10,098,321	3,828,325,240	10,241,363
Time of use	49,362,517	78,243	58,781,219	95,136	60,184,368	95,607
Large Use	284,558,813	542,026	31,976,489	86,975	30,253,072	80,718
USL	10,317,258		8,258,439		8,867,735	
Sentinel Lighting	445,736	1,201	461,891	1,330	544,242	1,381
Street Lighting	40,822,715	113,505	42,697,871	118,367	42,905,451	139,896
Total	**6,741,195,254**	**10,157,880**	**6,788,085,616**	**10,400,129**	**6,906,362,748**	**10,558,964**

Vulnerable Energy Consumers Coalition – Interrogatory #34

Question:

Reference: Exhibit C1/Tab 1/Schedule 3, pages 1-4

a) Since the forecast methodology of total purchased kWh does not include number of customers as an explanatory variable, how can PowerStream be assured that there is consistency between its forecast of kWh and its customer count forecast for 2009?

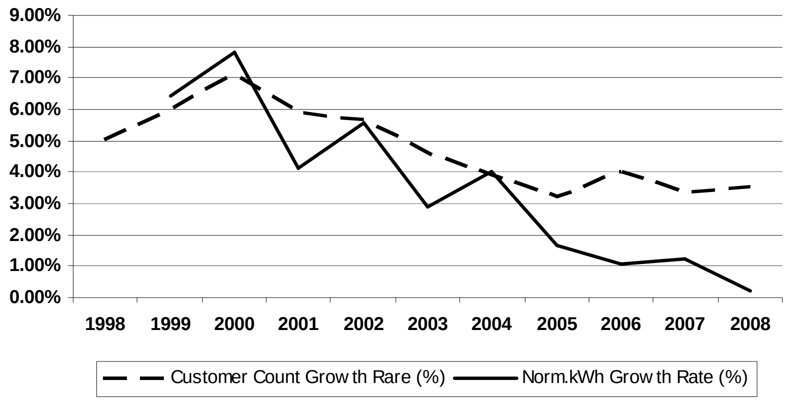
b) Please confirm whether the customer count values shown in Table 2 are year end value or average annual values. Please reconcile the total number of customers reported in Table 2 with the values shown for 2006-2009 at Exhibit C1/Tab 1/Schedule 4, page 7.

c) Please provide a revised version of Table 2 that shows the historical and projected customer count by customer class. Please include in the schedule the growth rate used for each commercial class to project 2008 and 2009 customer count.

Response

a) Historically, the trend of customer count was a good indicator to the trend of consumption. That is, when customers count grew, consumption grew. However in the more recent years this correlation has changed. Based on the changes that have been occurring in the electricity industry and customer awareness of conservation initiatives and their consumption habits, PowerStream has noted that actual use per customer over the last few years has been declining. Additionally, change in residential density with unit intensification causes load to grow consistently with customer base growth. PowerStream has endeavored to capture this in the load forecast methodology and has compared actual consumption results to test the accuracy of the methodology. The historic relationship between customer growth and load growth is outlined in the graph below.

Figure VECC 34-1: Customer Growth and Load Growth (1998-2008)



b) Exhibit C1-1-3, Table 2 on page 4 reports year-end customer count, whereas Exhibit C1-1-4, Table 2 on page 7 shows average values by year. See attached Schedule VECC 34-1 for the reconciliation details.

c) The revised version of Table 2 for the period 2006-2009 shows the customer count information by class.

Table VECC 34-2: Number of Customers by Customer Class

Rate Class	2006	2007	2008	2009	Growth used for Commercial Class
Residential	220,794	207,783	214,353	221,376	
GS<50	22,021	22,698	23,348	23,998	650
USL	2,006	2,028	2,088	2,148	60
GS>50	3,644	3,708	3,833	3,960	127
GS TOU	2	2	2	-	
Large User	4	1	1	1	0
Sentinel Lights	148	144	142	142	
Street Light Customers	47	13	13	13	
Total Customers	248,666	236,377	243,780	251,638	837

Vulnerable Energy Consumers Coalition – Interrogatory #35

Question:

Reference: Exhibit C1/Tab 1/Schedule 4, pages 1-9

a) The headings used in Table 4 indicate that the kWh and kW values shown are weather normalized. Please explain how PowerStream calculated the historic weather normalized use by customer class.

b) Are the 2008 values shown in Table 4 projected or actual values?

c) Please provide a schedule that sets out the actual sales per customer for each customer class for 2002-2008 and also include the forecast average use per customer for 2009. For customer classes that are demand billed please include both kWh and kW.

d) Please expand Table 7 to include all customer classes. Please also provide a similar table for demand billed customers showing kW/customer.

e) Please provide the actual 2008 customer count by class, including both the year end and average annual values.

f) With respect to page 9, please explain why the kW eligible for the transformer discount are increasing in 2009 (versus 2008) when Exhibit C1/Tab 1/Schedule 1, page 2 shows that totally billed kW are declining in 2009 relative to 2008.

g) What were the actual 2008 kWs eligible for the transformer discount?

Response

a) Historic weather normalized sales by customer class were derived using a top-down approach. The first step was to normalize the actual energy purchases for a calendar year by month and adjust the weather normalized volumes for actual losses incurred in the year. Then, the adjusted monthly figures were allocated to rate classes based on the actual rate class consumption allocations for that year.

b) The 2008 values Table 4 represent actual values.

c) Historic consumption/demand data by rate class prior to 2006 (i.e. prior to PowerStream merger and Aurora acquisition) is not sufficiently accurate and reliable for load forecasting or comparative purposes and therefore was collected and used. The actual consumption per customer and average demand per customer by rate class for which data are available are disclosed in the tables below.

Table VECC 35-1: Average Consumption by Customer Class (kWh/customer)

	Average Consumption (kWh/customer)				
	Billing determinant	Actual 2006 kwh/customer	Actual 2007 kwh/customer	Bridge Year 2008 kwh/customer	Test Year 2009 kwh/customer
Residential	kWh	10,089	9,981	9,783	9,326
GS Less Than 50 kW	kWh	36,042	35,430	35,137	33,887
GS 50 to 4,999 kW	kW	981,589	1,056,886	1,004,320	997,017
GS 50 to 4,999 kW Legacy	kW	24,568,233	29,396,178	30,228,400	28,037,810
Large Use	kW	69,368,744	31,986,565	30,339,590	31,414,814
Unmetered Scattered Load	kWh	4,769	4,127	4,176	3,865
Sentinel Lighting	kW	2,892	3,230	3,734	4,809
Street Lighting	kW	731	729	722	664
Average		**25,290**	**24,386**	**23,412**	**21,901**

Table VECC 35-2: Average Load by Customer Class (kW/customer)

	Average Load (kW/customer)				
	Billing determinant	Actual 2006 kW/customer	Actual 2007 kW/customer	Bridge Year 2008 kW/customer	Test Year 2009 kW/customer
Residential	kWh	0	0	0	0
GS Less Than 50 kW	kWh	0	0	0	0
GS 50 to 4,999 kW	kW	2,585	2,770	2,680	2,604
GS 50 to 4,999 kW Legacy	kW	38,943	47,520	47,973	43,527
Large Use	kW	132,133	86,879	80,893	82,809
Unmetered Scattered Load	kWh	0	0	0	0
Sentinel Lighting	kW	8	9	10	12
Street Lighting	kW	2	2	2	2
Average		**182**	**175**	**168**	**153**

d) The average consumption per customer and demand per customer by rate class are disclosed in the tables below.

Table VECC 35-3: Average Consumption by Customer Class (kWh/customer, Normalized)

	Average consumption (kwh/customer)				
	Board Approved 2006 kWh/customer	Actual Normalized 2006 kWh/customer	Actual Normalized 2007 kWh/customer	Bridge Year Normalized 2008 kWh/customer	Test Year 2009 kWh/customer
Residential	10,503	10,136	9,836	9,978	9,326
GS Less Than 50 kW	40,610	36,208	35,325	35,933	33,887
GS 50 to 4,999 kW	943,901	986,105	1,053,544	1,013,187	997,017
GS 50 to 4,999 kW Legacy	16,532,500	24,681,258	29,390,609	30,092,184	28,037,810
Large Use	78,771,153	69,687,873	31,976,489	30,253,072	31,414,814
Unmetered Scattered Load	5,278	4,791	4,067	4,279	3,865
Sentinel Lighting	2,278	2,905	3,180	3,833	4,809
Street Lighting	708	734	731	702	664
Average	**24,218**	**24,061**	**23,321**	**22,920**	**21,901**

Table VECC 35-4: Average Load by Customer Class (kW/customer, normalized)

	Average load (kw/customer)				
	Board Approved 2006 kw/customer	Actual Normalized 2006 kw/customer	Actual Normalized 2007 kw/customer	Bridge Year Normalized 2008 kw/customer	Test Year 2009 kw/customer
Residential	0	0	0	0	0
GS Less Than 50 kW	0	0	0	0	0
GS 50 to 4,999 kW	2,563	2,585	2,769	2,710	2,604
GS 50 to 4,999 kW Legacy	28,240	38,943	47,568	47,803	43,527
Large Use	142,396	132,133	86,975	80,718	82,809
Unmetered Scattered Load	0	0	0	0	0
Sentinel Lighting	6	8	9	10	12
Street Lighting	2	2	2	2	2
Average	**170**	**170**	**167**	**162**	**153**

e) The 2008 actual and average annual customer count by rate class is disclosed in the table below.

Table VECC 35-5: Actual and Average Number of Customer by Class

Rate Class	2008 Actual	2008 Average
Residential	215,323	211,459
GS < 50	23,268	23,032
USL	2,072	2,060
GS > 50	3,907	3,809
GS TOU	2	2
Large User	1	1
Sentinel Lights	141	141
Street Light Customers	15	14
Total Customers	**244,729**	**240,517**

f) The increase in estimated eligible kW is mainly due to the estimated increase in eligible kW for the GS>50 class. The kWs eligible for transformer allowance in 2009 were calculated based on historical averages of kW/customer. These assumptions were not updated at the time of application update, since actual 2008 data was not available.

g) The 2008 Actual data is

- Eligible (kW) = 3,089,556
- Transformer allowance = $1,853,733

Vulnerable Energy Consumers Coalition – Interrogatory #36

Question:

Reference: Exhibit C2/Tab 1/Schedule 1

a) Where are the SSS Admin charge revenues reported?

b) Please provide a brief description of the sources of "Other Distribution Revenue".

c) Please confirm that PowerStream excludes interest on regulatory assets from the determination of Other Revenue. If not, where is it included and how much is included for 2009.

Response

a) SSS Admin charge revenues are reported in the SSS Administration Charge Revenue account (4078). This amount is included in Other Distribution revenue, as shown in Exhibit C2-1-2, Table 2.

b) Please see Exhibit C2-1-2, Table 2 for a description of the sources of "Other Distribution Revenue".

c) PowerStream excludes interest on regulatory assets from the determination of Other Revenue.

Vulnerable Energy Consumers Coalition – Interrogatory #37

OM&A

Question:

Reference: D1 Tab 1 Schedule 1, page 1

a) With regard to benchmarking PowerStream's historic OM&A costs, please confirm/correct the data for 2005 and 2007 shown in the file "Comparison of Distributors (EB-2006-0268)" found on the OEB web site: http://www.oeb.gov.on.ca/OEB/_Documents/EB-2006-0268/Comparison_of_Distributors_with_2007_data.xls

2007	2006	2005
$42,993,55		
3	$38,591,483	$41,838,918

Please indicate the correct data for 2005-2007 and reconcile with Exhibit 1/Tab2/Sch1, Appendix B & Exhibit 3/Tab2/Schedule 1, Table 2

b) Please reconcile the 2006 and 2007 values in part (a) with those reported in Schedule 1.

c) Provide 2006-2009 (forecast) OM&A per kWh distributed.

d) Please discuss the high year to year variation in OM&A per customer and per kWh from 2006-2009.

e) Compare and discuss the position of PowerStream within the Cohort of comparable utilities.

Response

a) PowerStream is unaware of the Exhibit 1-2-1, Appendix B & Exhibit 3-2-1, Table 2 referred to in the interrogatory. Both tables (the table above from the PEG report and Table 1 in Exhibit D1-1-1) are correct. However they are used for different purposes. Please find the reconciliation in (b) below.

b)

Table VECC-37-1: OM&A Reconciliation

Powerstream - OM&A Expenses

			2006		2007
Total as per RRR	A	**$**	**38,591,483**	**$**	**42,993,553**
add (As per RRR spreadsheet)					
CDM		$	1,834,362	$	2,102,537
Charitable contributions		$	25,984	$	868,029
SMART meter offset				$	(23,812)
subtotal	B	$	1,860,346	$	2,946,754
Less					
Non-distribution expenses					
Non-recoverable:					
M&A expenses		$	10,188		709,732
M&A expenses					
Chariatble donations		$	10,984		838,029
Sponsorships		$	112,154		183,319
Ontario Capital tax		$	1,524,000		1,544,000
subtotal	C	$	1,657,326	$	3,275,080
Total adjusted RRR	D=A+B-C	$	38,794,503	$	42,665,227
As per 2009 EDR model (Exhibit D1)		**$**	**38,794,503**	**$**	**42,665,227**

c)

Table VECC-37-2: OM&A Cost per Mwh

	2006 OEB Approved	2006 Actual	2007 Actual	2008 Bridge	2009 Test Year
OM&A,$	38,282,888	38,794,503	42,665,227	39,649,381	45,098,300
Mwh	6,425,946	6,741,195	6,788,086	6,906,363	6,829,307
OM&A per Mwh, $/Mwh	$ 5.96	$ 5.75	$ 6.29	$ 5.74	$ 6.60

d) The table below shows the required information, updated to 2008 actual data.

Table VECC-37-3 OM&A per Customer and OM&A/Mwh

	2006 Actual	2007 Actual	2008 Actual	2009 Test Year
OM&A,$	38,794,503	42,665,227	44,646,163	45,098,300
Customers	228,666	236,377	243,780	251,638
Mwh	6,741,195	6,788,086	6,814,690	6,829,307
OM&A /customer,$	169.7	180.5	183.1	179.2
OM&A per Mwh, $/Mwh	$ 5.75	$ 6.29	$ 6.55	$ 6.60

As evidenced in table above, despite year-to-year variances, PowerStream has been able to keep the costs relatively stable, so that forecasted 2009 OM&A per customer are at the level of 2006 Board Approved. PowerStream does not support OM&A costs per Mwh as a performance indicator for rate making purposes.

Please note that OM&A per customer ratios in the table above are slightly different from the ones in the benchmarking file, for two reasons:

1. The difference between OM&A expenses in PowerStream's 2009 EDR model and total OM&A used for benchmarking purposes is explained in our response to IR 37 (a) above.

2. The customer numbers above include street and sentinel lighting, which were excluded in benchmarking calculation.

e) Please refer to PowerStream's response to SEC-5.

Vulnerable Energy Consumers Coalition – Interrogatory #38

Question:

Reference: Exhibit A2/Tab 1/Schedule 1, page 8, lines 127-135
Exhibit D1/Tab 1/Schedule 1, pages 1-10

a) What are the total labour costs included in each year's OM&A from 2006 actual to 2009 forecast?

b) Per page 3, lines 45-51, please provide a schedule that sets out the customers/employee ratio for 2006 to 2009. Please include in the schedule the employee and customer counts used in the calculation and reference where they can be found in the Application.

c) Please confirm that the increased costs attributed to "Staff" in Table 3 do not include the 3 new cable locators (per page 4, lines 66-73).

d) Please provide the basis for the estimated $3 M expenditure on IFRS (page 5) and details regarding the planned $750,000 spending included in 2009 rates.

e) With respect to Table 3, why are there no reductions in OM&A expense attributed to productivity improvements over the period?

f) With respect to Table 4, please indicate which of the listed factors can be considered one-time non recurring items as opposed to ongoing items.

g) With respect to Table 5 does the fact the updated burden rates increase OM&A by $2 M mean that less costs are capitalized under the new burden rates? If not, pleased explain the basis for the $2 M.

h) The dollar amounts attributed to the explanations provided in these pages (pages 7-10) do not appear to align with the dollar amounts attributed to the various factors in Table 3. Please provide a similar schedule to Table 3 (D1/1/1) that explains the contribution of each of these major cost drivers (and any other deemed to be relevant) to the year over year changes in total OM&A from <u>2006 actual</u> to 2009 forecast.

Response

a) PowerStream's evidence in Exhibit D1-1-1 page 3 of 10 (line 30) overstates the proportion of OM&A expenses that are labour. The table below more accurately reflects that labour costs are approximately 56% of OM&A expenses.

b)

Table VECC 38-1: OM&A Labour Expenses 2006 – 2009 ($000)

$000's	2006 Actual	2007 Actual	2008 Bridge	2009 Test
OM&A expenses	38,795	42,665	39,649	45,098
Labour costs	21,725	23,893	22,204	25,255

b) PowerStream's customers per employee has been relatively stable over the period 2006 – 2009.

Table VECC 38-2: Customer/Employee Ratio 2006 – 2009

$000's		2006 Actual	2007 Actual	2008 Bridge	2009 Test
Customers	Ex D1/1/1, table 2	228,666	236,377	243,780	251,638
Employees	Es D1/1/9, table 2	360	370	387	401
Customers/employee		635	639	630	628

c) The increased costs attributed to "Staff" in Table 3 do not include the 3 new cable locators.

d) Please refer to PowerStream's response to Staff-46.

e) The cost impacts shown in the Table 3 are net of OM&A reductions due to productivity improvements.

f) All listed factors can be considered ongoing items, with the exception of the increase of $0.3M in billing and collection, which was a result of prior period adjustments.

g) Please refer to PowerStream's response to VECC-12.

h) Please refer to PowerStream's response to SEC-25(a).

Vulnerable Energy Consumers Coalition – Interrogatory #39

Question:

Reference: Exhibit D1/Tab 1/Schedule 3, pages 1-12

a) Please provide a schedule that sets out the actual OM&A expenses for 2008 broken down as per Table 1.

b) Please provide a schedule that sets out the actual Operations and Maintenance expenses for 2008 broken down as per Tables 2 &3.

c) What was the basis for the decision that increased maintenance was required on Transformer Stations in 2007 and subsequent years relative to 2006 spending levels (per page 7)?

d) What was the basis for the decision that increased maintenance was required on Distributor Stations in 2007 and subsequent years relative to 2006 spending levels (per page 4)?

e) What was the basis for the decision that increased lines inspection was required for 2007 and subsequent years (per page 7)?

f) Are there any Operations or Maintenance activities where, for 2009, resources will be shared between the Barrie and PowerStream Divisions? If so, please provide a schedule that identifies these areas and provide the following:

- **The total costs shared costs incurred by the Barrie and PowerStream Divisions**
- **The amount charged to the PowerStream Division and the basis for it determination.**

Please confirm where the amounts charged to the PowerStream Division for each activity are reported (e.g. which USOA account).

Response

a) Please refer to PowerStream's response to EP-16(a).

b) Please refer to PowerStream's response to EP-16(a).

c) **Table VECC-39-1 – Operating and maintenance expenses on transformer and distributor stations 2006-2009 ($000)**

	2006 Actual	2007 Actual	2008 Bridge	2009 Test Year
O&M expenses on transformer and distribution stations	1,214	1,441	1,786	2,367
YOY variance, $		227	345	581
YOY variance, %		19%	24%	33%

The most accurate analysis of Powerstream's O&M expenses on stations should be done on a combined basis. There are aspects of preventative maintenance, such as testing, that are captured in the operations expenses, whereas repairs are captured under the maintenance expenses. Both are maintenance related costs and, combined, provide a more comprehensive picture of the overall maintenance programs. In 2007, PowerStream initiated increased testing programs, such as Doble testing of all power transformers, which allows us to better predict developing problems and asset performance. Over the period in question, we also added an additional transformer station (Vaughan TS#1, see B1-1-1), and three distribution stations in Aurora, which results in increased maintenance and operation expenses.

d) Please refer to PowerStream's response to (c) above.

e) Beginning in 2007, PowerStream implemented a number of new operation and maintenance programs that allowed for a higher level of inspection and earlier identification of potential issues. PowerStream decided to implement these programs in order to continue to provide reliable service and prevent outages and failures. The programs include, for example, pole inspection and Infra-Red scan of overhead and underground lines. These programs identify many "hot spots", perform preventative maintenance and fix the lines before serious issues happened.

f) There is no expected change in the cost of the O&M programs in the PowerStream rate zone as a result of the merger.

Vulnerable Energy Consumers Coalition – Interrogatory #40

Question:

Reference: Exhibit D1/Tab 1/Schedule 3, pages 13-19

a) Please provide a schedule that sets out the actual Administration expenses for 2008 broken down as per Table 4.

b) Are there any costs included in either 2008 or 2009 with respect to the 2009 Rate Application? If yes, please indicate the amounts by year and provide details as to what the expenses are for.

c) What is the cost of the MEARIE Bad Debt insurance for 2009 and is this the first year PowerStream has purchased this insurance (per page 19)?

d) Why is it reasonable to use bad debt history from a period when there was no Bad Debt insurance purchased to estimate bad debt costs for 2009 – a year where PowerStream has bad debt insurance?

e) Please provide a break down of 2006 (actual) to 2009 (forecast) annual Administrative and General costs by the OEB's USOA accounts.

f) Are there any Administrative & General activities where, for 2009, resources will be shared between the Barrie and PowerStream Divisions? If so, please provide a schedule that identifies these areas and provide the following for each:

- **The total costs incurred by the Barrie and PowerStream Divisions**
- **The basis for determining the amount to be charged to the PowerStream Division.**

Please confirm where the amounts charged to the PowerStream Division for each activity are recorded (e.g., which USOA account).

Response

a) Please refer to PowerStream's response to EP-16(a).

b) Please refer to PowerStream's response to EP-16(b-d).

c) Please refer to the PowerStream's response to Staff-43(b).

d) Bad Debt Insurance does not cover all the bankruptcy risks; a reserve is still required. PowerStream relies on bad debt history as a means of estimating the appropriate amount of the reserve.

The forecast of bad debt expense for 2009 is net of those amounts that will be covered by insurance. Note that the $982,000 for insurance in D1-1-3, Table 4 is for all types of insurance except for bad debt insurance. The cost of the bad debt insurance is in the $1.236M amount for bad debt.

e) Please refer to PowerStream's response to Staff-36.

f) Please see the response to Staff-35.

Vulnerable Energy Consumers Coalition – Interrogatory #41

Question:

Reference: Exhibit D1/Tab 1/Schedule 4, pages 1-4

a) Please provide a schedule that sets out the total payments for purchases services and products for 2006-2009 broken down by USOA account.

Response

a) Please refer to PowerStream's response to Staff - 48 for more details on purchased services and products for 2006-2009

Vulnerable Energy Consumers Coalition – Interrogatory #42

Question:

Reference: Exhibit D1/Tab 1/Schedule 5, pages 1-2

a) Using the TS Primary <50 asset group, please provide a sample calculation of how 2009 depreciation expense was determined.

Response

a)

Table VECC 42-1: Asset Additions TS Primary above 50

Asset Class	Usefule Life (A)	2008 Capital Additions (B)	2009 Capital Additions (C)
1815 Transformer Station	40	1,837,260	14,451,697

Table VECC 42-2: 2009 Depreciation Expense Calculation

Asset Class	2008 Base Depreciation (per Table 1) (D)	Adjustment to reflect full year Depreciation on 2008 Additions (E)=(B)/(A)*50%	2009 Depreciation on additions (1/2 year rule) (F)=(C)/(A)*50%	2009 Depreciation Expense (D)+(E)+(F)
1815 Transformer Station	2,339,263	22,966	180,646	2,542,875

Vulnerable Energy Consumers Coalition – Interrogatory #43

Question:

Reference: Exhibit D1/Tab1/Schedule 6, page 1 and Schedules 7 and 8

a) Provide a copy of PowerStream's Corporate/affiliate relationships chart.

b) Provide copies of the executed signature pages of Schedules 7 and 8 and the executed copies of the Service Schedules for 2009.

c) Provide a consolidated Schedule that shows 2008 actual and forecast 2009 and 2010 amounts for inbound and outbound services for each of Vaughan and Markham. Indicate for which services, pricing is market based and for which pricing is based on the cost of the service provider.

d) Are services provided by Vaughan or Markham to any other affiliates except the City/town Departments? If so indicate how the costs are allocated between affiliates/related parties and provide copies of the Coat Allocation methodology.

e) Are services provided by PowerStream to any affiliates/related parties other than Vaughan/Markham City/Town departments? If so indicate how the costs are allocated between affiliates/related parties and provide copies of the Coat Allocation methodology.

Response

c) Please refer to Appendix A, Schedule 10 of the pre-filed evidence Corporate Entities Relationship Chart.

b) Please refer to the response to Staff 49(a).

c) Please see the following tables:

Table VECC 43-1: Inbound and Outbound Services - Vaughan

City of Vaughan (COV)	2008A	2009F	2010F	Basis
Out to COV - Facilities	$717,532	$731,882	$746,520*	Market
Out to COV – IT	37,000	37,740	38,495	Cost
Out to COV – Fuel Service Charges	21,291	11,158	11,404	Cost
In to PowerStream - Payroll	260,075	266,091	272,253	Cost
In to PowerStream – Cashier	231,671	235,965	240,972	Cost
In to PowerStream – Water Meter Reading & Billing	1,376,148	1,414,367	1,439,592	Cost

* Will be lower when PowerStream occupies new operations centre.

Table 43-1: Inbound and Outbound Services - Markham

Town of Markham (TOM)	**2008A**	**2009F**	**2010F**	**Basis**
Out to TOM - Facilities	$110,411	$120,000	nil	Market
Out to TOM – Cashier	21,319	81,930	$84,388	Cost
In to PowerStream - Water Meter Reading & Billing	1,363,337	1,401,200	1,426,190	Cost
In to PowerStream – Street Lighting Services	1,178,897	800,000	800,000	Cost

d) Services are provided by the City of Vaughan and by the Town of Markham to PowerStream only. (PowerStream is a distributor only.) PowerStream provides services to the City of Vaughan and to the Town of Markham.

e) No.

Vulnerable Energy Consumers Coalition – Interrogatory #44A

Question:

Reference: Exhibit D1/Tab 1/Schedule 9

a) Please provide an organization chart for the PowerStream division.

b) Using the chart, please indicate business unit areas where services/activities are shared with the Barrie Division.

c) With respect to Table 1, please provide a schedule that sets out the functional areas for the 64 new staff (e.g., Billing and Collecting, Operations, etc.).

d) With respect to Table 1 and the response to part (c), please provide more details as to the new requirements that increased staff by 45 and how growth triggered the need for 19 additional staff.

e) With respect to Table 2, please break the Unionize head count for each year down between "outside" and "inside" workers (per page 4).

f) Provide a comparison of the increase in total customers and revenue and total compensation from 2006-2009 (forecast) (page 6, Table 4).

g) Provide a copy of the latest compensation comparison study for Senior Management and Management (per page 8).

Response

a) Please refer to pre-filed evidence, Appendix A, Schedule 9.

b) Please refer to Staff 35.

c) Please refer to Table VECC 44A-1 below.

Table VECC 44A-1: New Staff Positions by Functional Area

Area	2006	2007	2008	2009	Total	
CDM	1				1	
Customer Service/Billing	5	4	1	2	12	
Engineering Design/Connections	5			1	6	2006 - 4 locators
System Planning	2			1	3	
HR & Safety	2	1		1	4	includes environmental co-ord
Finance and Accounting		1	1		2	
Rates and Regulatory	1	4			5	
Corporate Services & IT	5			2	7	includes communications dept, lawyer

Area	2006	2007	2008	2009	Total	
Asset Management	1	7	6	7	21	includes apprentices, meter clerk
Corporate Performance		2			2	
Stores			1		1	
Total	22	19	9	14	64	

d) In the table provided in the response to part (c), six of the customer service positions, two of the engineering design/connections positions and eleven of the asset management positions are due to growth. The remaining positions are for new or increased regulatory and other requirements.

e) **Table VECC 44A-2: Breakdown of Unionized Headcount**

Union Staff	2006 EDR	2006	2007	2008	2009
Inside	103	98	101	110	114
Outside	134	128	131	143	149
Total	237	226	232	253	263

f) **Table VECC 44A-3: Comparison of Compensation, Customer, and Revenue Growth**

	2006 Board Approved	2006 Actual	2007 Actual	2008 Bridge Year	2009 Test Year
Customers	213,500	228,666	236,377	243,780	251,638
Customer growth		7.1%	3.4%	3.1%	3.2%
Compensation ($000)	31,077	37,185	40,373	41,287	43,743
Increase in Compensation		19.7%	8.6%	2.3%	5.9%
Total Distribution Revenue ($000)	102,251	102,339	109,851	107,283	120,304
Increase in Distribution Revenue		0.1%	7.3%	-2.3%	12.1%

g) Please see response to SEC-31.

Vulnerable Energy Consumers Coalition – Interrogatory #44B

Question:

Reference: Exhibit D1/Tab 1/Schedule 10

a) Does PowerStream have any explanation for the higher than average actual loss factor in 2007?

Response

a) There was a technical problem with the workstation that ran the unbilled accrual at December 31, 2007 resulting in an understatement of the unbilled kWhs. This was addressed in 2008 and procedures put into place to provide a more thorough check of the unbilled accrual report.

Vulnerable Energy Consumers Coalition – Interrogatory #45

Question:

Reference: Exhibit D2/Tab 1/Schedule 3, page 4

a) Please update the 2009 CCA calculations (and subsequent tax calculations) to reflect the revision in CCA rates introduced in the 2009 Federal Budget.

Response

a) Please see PowerStream's response to Staff - 52.

Vulnerable Energy Consumers Coalition – Interrogatory #46

DEFERRAL AND VARIANCE ACCOUNTS

Question:

Reference: Exhibit E/Tab 1/Schedule 1, pages 1-5

a) Please confirm that the balance in Account #1590 which is proposed for disposition includes rate rider revenues up to April 30, 2008.

Response

a) Yes

Vulnerable Energy Consumers Coalition – Interrogatory #47

COST OF CAPITAL AND RATE OF RETURN

Question:

Reference: Exhibit F/Tab 1/Schedule 1

a) Please provide an update regarding the planned new debt issue for 2009 in terms of anticipated principal amount and interest rate (per page 3).

b) Provide a copy of the EDFIN Debenture (or term sheet). If not included explain how

i. the annual rate is established
ii. The issue costs and how these are recovered from PowerStream and the other participants

c) Provide a copy of the Term Sheet for the TD loan. If not included, explain how

iii. the annual rate is established
iv. the issue and any other costs are recovered

Response

a) At this time, PowerStream is still scheduled to secure $25 million in debt for 2009. PowerStream is still budgeting that the debt will be issued with an interest rate of 5.08%.

b) A copy of the EDFIN debenture term sheet will be filed in confidence in accordance with the Board's Rules of Practice and Procedure and its Practice Directions on Confidential Filings.

c) A copy of the TD term sheet will be filed in confidence in accordance with the Board's Rules of Practice and Procedure and its Practice Directions on Confidential Filings.

Vulnerable Energy Consumers Coalition – Interrogatory #48A

Question:

Reference: **Exhibit F, Tab1 Schedule 2 page 5**

Preamble: **The OEB has updated its cost of capital parameters for 2009**

a) Please update the 2009 values for the various schedules on page 5.

Response

a) The updated Cost of Capital Continuity Schedule is shown in Table VECC-48A, below:

Table VECC-48A: Cost of Capital Continuity

COST OF CAPITAL

Deemed Debt Rate and D/E Structures

	Board Approved	Historic Actual		Bridge Year	Test Year
	2006 Approved	2006 Actual	2007 Actual	2008	2009
Rate Base	$440,635,822	$445,146,537	$462,751,532	$494,574,363	$533,832,432
Debt Rate - Long Term	5.90%	5.90%	5.90%	6.10%	7.62%
Debt Rate - Short Term	5.00%	5.00%	4.59%	4.47%	1.33%
Deemed Debt	60.00%	60.00%	60.00%	60.00%	60.00%
Long-Term	60.00%	60.00%	60.00%	56.00%	56.00%
Short-Term				4.00%	4.00%
Deemed Equity	40.00%	40.00%	40.00%	40.00%	40.00%

Debt Rate (DR)

	Board Approved	Historic Actual		Bridge Year	Test Year
	2006 Approved	2006 Actual	2007 Actual	2008	2009
Long-term debt rate (as calculated)	6.16%	6.16%	6.14%	5.96%	5.89%
Short-term debt rate (deemed)	5.00%	5.00%	4.59%	4.47%	1.33%

Return on Equity

Target ROE	9.00%	9.00%	9.00%	8.57%	8.01%
Allowed ROE for Revenue Requirement Calculation	9.00%	9.00%	9.00%	8.57%	8.01%

	2006 Approved	2006 Actual	2007 Actual	2008	2009
Weighted Average Cost of Capital	7.30%	7.29%	7.28%	6.94%	6.56%

Note:
The Weighted Average Cost of Capital is calculated, based on the deemed capital structure

Vulnerable Energy Consumers Coalition – Interrogatory #48B

COST ALLOCATION

Question:

Reference: Exhibit H/Tab 1/Schedule 1

a) **Please describe more fully the work undertaken by Hydro One Networks.**

b) **Did Hydro One Networks prepare any weather normalized load profiles for PowerStream? If so, please provide Hydro One Networks estimate of weather normalized use per customer (kWh) for each customer class.**

Response

a) Hydro One's 2009 load profiles are based on PowerStream's monthly forecast by customer class, which is based on normal weather. Hydro One derived the hourly load shapes by class (as it did for the 2006 filing) and used them to develop the six allocators. PowerStream also provided details regarding the Large Use class due to the significant change in that class.

b) Hydro One did not provide weather normalized use per customer (kWh).

Vulnerable Energy Consumers Coalition – Interrogatory #49

Question:

Reference: Exhibit H/Tab 1/Schedule 2

a) Please provide a copy of the Cost Allocation Study Update for 2009. Note: Please provide hard copies of Sheets I6 and O2 as well as an electronic copy of the Excel Model results.

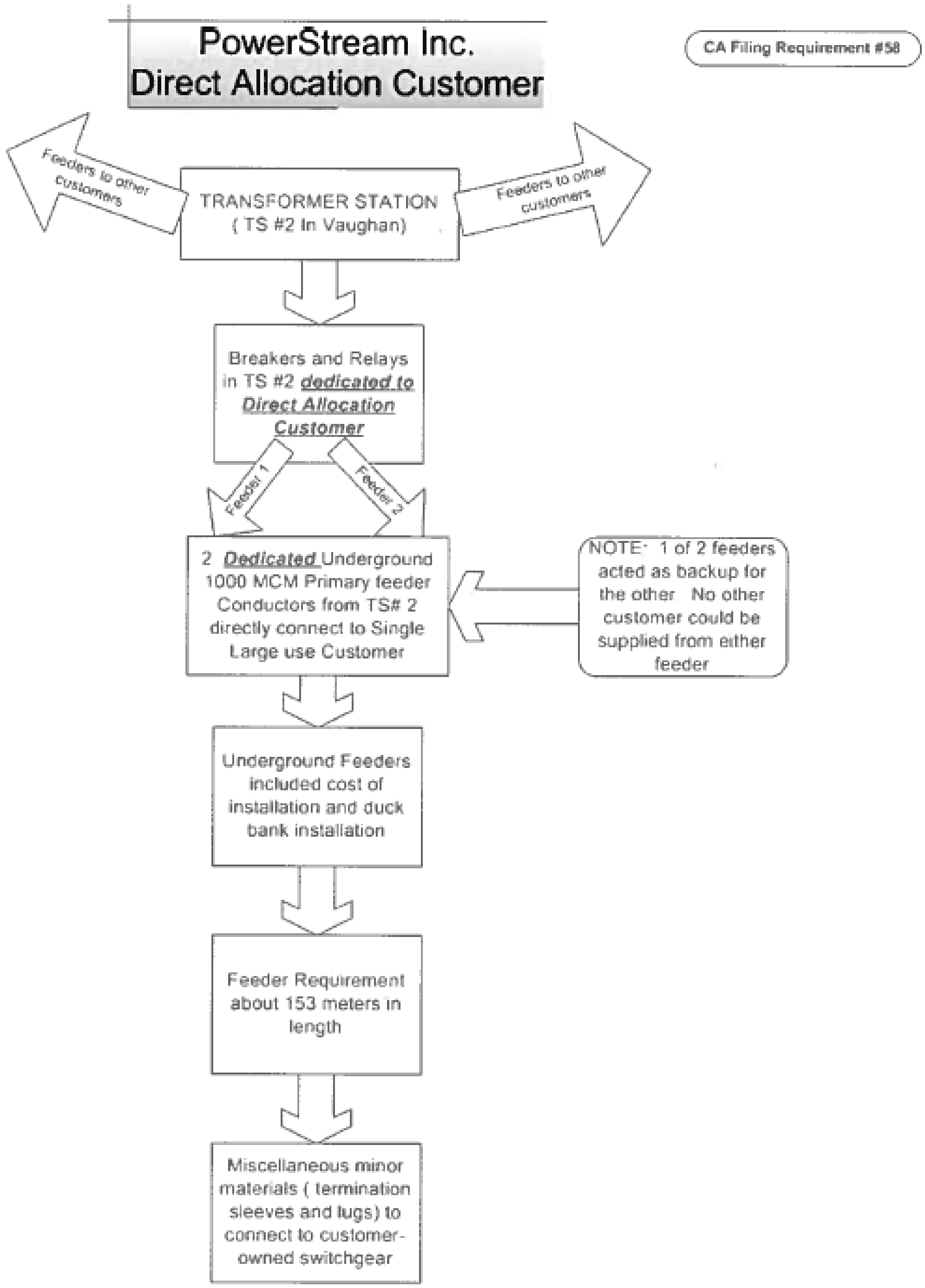
b) Please provide a "line diagram" illustrating the supply arrangements to the Large Use customer, including any facilities that could be used to supply the customer in the event the main feeder facilities were out of service (per page 2). Using this "line diagram" please describe the assets that were directly allocated to the Large Use class.

c) Please provide a schedule that sets out the relative kWh's by customer class as forecast in Exhibit C1 and as used in the Cost Allocation Update (per page 4).

Response

a) See response to Staff 60-1.

b) Due to the age of the installation, the drawings went to storage many years ago and we are not able to locate these in a timely manner. See the flowchart below which was included in the 2006 Cost Allocation Study.


PowerStream Inc.
Direct Allocation Customer
CA Filing Requirement #58
Feeders to other customers
TRANSFORMER STATION (TS #2 In Vaughan)
Feeders to other customers
Breakers and Relays in TS #2 dedicated to Direct Allocation Customer
Feeder 1
Feeder 2
2 Dedicated Underground 1000 MCM Primary feeder Conductors from TS# 2 directly connect to Single Large use Customer
NOTE: 1 of 2 feeders acted as backup for the other No other customer could be supplied from either feeder
Underground Feeders included cost of installation and duck bank installation
Feeder Requirement about 153 meters in length
Miscellaneous minor materials (termination sleeves and lugs) to connect to customer-owned switchgear

c) The table below compares the kWhs by customer class in the updated load forecast (January 2009) to the kWhs submitted for the Cost Allocation load profiles (March 2008).

Table 49-1: Updated Load Forecast vs. Cost Allocation

	Residential	**GS <50 kW**	**USL**	**GS>50 kW**	**Large Users**	**Street-Lighting**	**Sentinel**	**Total**
Updated Load Forecast	2,034,450,648	803,126,540	8,195,169	3,909,095,504	31,414,814	42,341,705	682,931	6,829,307,309
% of Total	29.8%	11.8%	0.1%	57.2%	0.5%	0.6%	0.0%	100.0%
Cost Allocation	2,214,110,970	871,611,091	10,511,322	4,270,739,545	35,072,200	44,577,164	526,989	7,447,149,280
% of Total	29.7%	11.7%	0.1%	57.3%	0.5%	0.6%	0.0%	100.0%

Vulnerable Energy Consumers Coalition – Interrogatory #50

Question:

Reference: Exhibit H/Tab 1/Schedule 3

a) Please explain how the Distribution Revenue by Customer class (as set out in Exhibit I/Tab 1/Schedule 1, page 2) was determined for purpose of preparing the Cost Allocation Update. Please provide supporting schedules setting out the actual derivation of the distribution revenues used in the Cost Allocation for each rate class.

b) Based on Exhibit C1/Tab 1/Schedule 4, page 9, it appears that under the currently approved rates the Large Use customer receive the transformer discount. Please confirm if this is the case.

c) Please confirm whether the revenues reported for the Large Use customer ($215,920) and the GS>50 class ($39,193,181) have been reduced by the respective transformer discounts for each class.

d) If the revenues for either the Large Use or GS>50 class have not been reduced to account for the transformer discount please re-do the Cost Allocation run using revenues for each of these classes that are net of the transformer discount. Please provide the resulting Sheet O1.

e) Please confirm that PowerStream followed the Board's direction regarding the allocation of General and Administrative Costs.

f) Please breakdown Power Stream's G&A Expenses ($22,628,209) between:

- **Property Insurance**
- **Community Safety Programs**
- **Remaining G&A Expense**

g) Please provide a schedule that sets out the allocation of each of these components to customer classes and the allocation factors used. (Note: For the allocation factors please describe each allocation factor and provide the absolute values by customer class as well as the percentages).

h) Please provide a schedule that shows the expenses directly allocated to the Large Use class (Total = $9,267) by USOA account. For each USOA account please describe how the directly allocated costs were identified.

i) Please confirm that the O&M costs directly allocated to Large Use class were included in the Allocation Base used to pro-rate the "Remaining A&G" costs

from part (f) above to customer classes. If this is not the case, please provide an alternate Cost Allocation Run where remaining A&G costs are pro-rated to customer classes based on the O&M costs allocated to classes (including directly allocated O&M).

j) **Please provide a schedule that shows the net fixed assets directly allocated to the Large Use class (Total = $100,089) by USOA account. For each USOA account please describe how the directly allocated costs were identified.**

k) **Please confirm that the Net Fixed Assets directly allocated to Large Use class were included in the Allocation Base used to pro-rate "General Plant" costs to customer classes. If this is not the case, please – as part of the response to part (i) - provide an alternate Cost Allocation Run where General Plant costs are pro-rated to customer classes based on the Net Fixed Distribution Assets allocated to classes (including directly Net Fixed Assets).**

Response

a) Table 1 in Exhibit I-1-1 (reproduced below as Table VECC-50-1) shows the revenue allocation between classes. The "2009 Test Year at calculated rates" shows the resulting revenue allocation on the same basis as current rates (see table below) and the proposed allocation taking into account the results of the Cost Allocation study update.

Table VECC 50-1: Revenue Allocation

Class	2009 Customer count	2009 customer count x average kwh per cust.	2009 customer count x average kw per cust.	2008 Approved Fixed Month Rate	2008 Approved Variable Rate	Distribution Revenue	Revenue Allocation
Residential	218,157	2,142,023,103		12.02	0.0129	59,099,102	50.81%
GS<50	23,700	837,519,589		28.70	0.0112	17,542,528	15.08%
GS>50	3,902	3,978,724,035	10,463,528	301.73	2.2713	37,894,168	32.58%
Large Use	1	31,356,478	84,266	8,978.09	1.1989	208,764	0.18%
USL	2,121	9,013,064	-	14.35	0.0111	465,195	0.40%
Sentinel Lighting	142	522,824	1,386	2.01	6.0151	11,759	0.01%
Street Lighting	63,805	45,152,565	133,064	0.84	3.3980	1,095,302	0.94%
Total	311,828	7,044,311,657	10,682,244			116,316,819	100.00%

The Revenue Allocation is based on distribution revenue calculated using 2009 customer numbers, average consumption for 2006 through 2009 and approved 2008 rates (excluding Smart Meter, Regulatory Asset and Low Voltage rate adders/riders). These percentages were applied to the calculated revenue requirement to assign revenue to customer classes.

See Schedule VECC 50-1 for the calculation of the Cost Allocation adjustment.

The ratios are calculated by comparing the Total Revenue (Cost allocated), as calculated by the Cost Allocation model, to the sum of the distribution at current rates plus miscellaneous revenue, on a class by class basis.

As highlighted in the "Revenue/Expense Ratio" section, under "Test Year at Calculated Rate", there are three classes where this ratio falls outside the ranges specified in the "*Application of Cost Allocation for Electricity Distributors, Report of the Board EB-2007-0667, November 28, 2007*".

In the case of the Sentinel Lighting and Street Lighting classes, the revenue collected from these classes at the calculated rates falls below the threshold amount (i.e. 70% of the allocated costs), indicating a need to increase the amount of revenue collected from these classes. In the case of the Large Use class the revenue collected from this class exceeds the ceiling amount (115% of allocated costs), indicating the need to reduce the amount of revenue collected from this class.

The "Distribution Revenue Re-allocation" shows the necessary adjustment to the class revenue allocation to bring it to the acceptable range set by the Board.

There is a remaining amount of $56,000 needed to make the re-allocation net to $0. This has been allocated to the Residential Class where it has minimal impact.

b) PowerStream has customers in both General Service >50 kW and Large Use class that own their own transformers and receive the Transformer Allowance.

c) PowerStream has excluded the transformer allowance revenues and costs in the cost allocation model and in the calculation of Revenue Requirement.

d) The cost allocation model has allocated actual transformer costs (as well as other costs) based on actual usage by each class. It does not include costs for customer owned transformers (as customers bear these costs) nor has transformer allowance added to revenues allocated, No adjustment to the model is considered necessary.

   PowerStream has treated the transformer allowance cost as representing the additional cost it would incur to provide transformation to the entire GS>50 kW and Large Use class if no customers owned their own transformers. The transformer allowance cost has been divided by the total kWs billable to these classes and this amount has been added to the rates for these two classes so that the rates include the full cost of providing transformation to these classes. This is the proper starting point for customers then to receive a credit for providing their own transformation.

e) PowerStream did not make any manual adjustments to change the trial balance amounts on I3. On checking it was discovered that the trial balance accounts did not split out the amounts shown in part f) below into the trial balance accounts as expected by the Cost Allocation model

f) The requested breakdown of the G&A expenses is:

Table VECC 50-2: G&A Expense

G&A Expenses	Amount	%
Property Insurance	972,416	4.5%
Community Safety	52,000	0.2%
Other	21,603,793	100.0%

g) PowerStream has rerun the model with the necessary adjustments as described in part e) above. It has the following effect:

Table VECC 50-3: Adjusted Analysis

Revenue Requirement (includes NI)	Total	Residential	GS <50	GS>50-Regular	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load
Corrected allocation re A&G	126,872,208	69,367,110	17,354,551	37,819,728	52,678	1,779,094	27,585	471,461
As filed	126,872,208	69,397,488	17,389,590	37,753,577	52,480	1,776,238	27,548	475,287
Change	-	(30,377)	(35,039)	66,152	197	2,855	37	(3,826)
Change - %	0.00%	-0.04%	-0.20%	0.18%	0.38%	0.16%	0.13%	-0.80%
Number of Customers		218,157	23,700	3,902	1	13	142	95
Monthly Amount per customer		(0.01)	(0.12)	1.41	16.46	18.30	0.02	(3.36)

h) The directly allocated expenses for the Large Use class are:

Table VECC 50-4: Large Use – Directly Allocated Expenses

USOA Account	Allocated	Comments and Explanations
6110	$ 877	Approved total PILs CA model automatically calculates a proportion of the total pils based on the total directly allocated costs ($100,090) compared to total net fixed assets ($1,017M)
6005	$ 1,813	Approved interest on long term debt. CA model automatically calculates a proportion of the total debt based on the total directly allocated costs ($100,090) compared to total net fixed assets ($1,017M)
3046	$ 1,768	Approved return on equity. CA model automatically calculates a proportion of the total expected earnings based on the total directly allocated costs ($100,090) compared to total net fixed assets ($1,017M)
5705	$ 5,169	Depreciation calculation based on 25 year life on cable ($74K) and 40 yr. life on Ts breakers and relays $88K)
Total	**$ 9,627**	

i) PowerStream did not make any manual adjustments to change the allocation of General Administrative costs in the Cost Allocation (CA) model provided by the Board.

j) The directly allocated net fixed assets for the Large Use class are:

Table VECC 50-5: Large Use-Directly Allocated Net Fixed Assets

USOA Account	Allocated	Comments and Explanations
1815	87,710	TS station equipment. Dedicated breakers and relays as advised by Station Engineering
1845	74,400	Underground lines and devices. 300m of 3 phase feeder cables (6 lines) 1000mcm, duct bank for cable, misc. materials. As advised by engineering management
2105	(62,020)	Estimated accumulative depreciation on above assets. Infrastructure about 12 yrs old per control room
Total	100,090	

k) PowerStream did not make any manual adjustments to change the allocation of “General Plant costs” in the Cost Allocation (CA) model provided by the Board.

Vulnerable Energy Consumers Coalition – Interrogatory #51

RATE DESIGN

Question:

Reference: Exhibit I/Tab 1/Schedule 1

a) Please explain more fully the fixed rate mitigation adjustment that Power Stream deemed was required for the one customer in the Large Use class (per page 2, lines 33-35).

b) Please provide a schedule that demonstrates that proposed rates for each customer class (net of LV and Smart Meter adders) yield the allocated revenue requirement for the class.

c) Please explain why the unit rate for the transformer discount adder is the same ($0.2483) for the Large Use and GS>50 class.

d) Please confirm that the Cost Allocation Update does not allocate any transformer costs to the Large Use class.

• If this is the case, why is it necessary to offer this class a transformer discount as opposed to simply basing its rates on the results of the cost allocation – following the adjustment of the revenue to cost ratios
• Alternatively, if the class is to receive a discount why isn't the cost of the discount received by the class (i.e., $49,685 per Exhibit C1/Tab 1/Schedule 4) assigned directly to the class?

e) Why isn't the transformer ownership rate adder for the GS>50 class calculated so as to recover the cost of providing the discount to the customers in that class (i.e., $2,501,422 per Exhibit C1/Tab 1/Schedule 4)

Response

a) This was not a rate mitigation adjustment in that there is only one customer in this class and altering the fixed variable shift would not mitigate rate change impacts. The fixed monthly charge was reduced to obtain a more reasonable split between the fixed and variable rate. The reduction in the fixed charge was offset by an increase in the variable rate so that the total revenue to be collected from this class was equal to the revenue allocated in the Cost Allocation adjustment (see response to question 50).

b) The table below shows the distribution revenue generated by the proposed rates.

Table VECC 51-1: Distribution Revenue

Customer Class	Fixed rate	Customer /Connections	Variable rate	volume	Total proceeds
Residential	12.43	218,157	0.0141	2,034,450,648	$ 61,226,092
GS Less Than 50 kW	28.7	23,700	0.0124	803,126,540	$ 18,121,078
GS 50 to 4,999 kW	301.73	3,902	2.4668	10,160,712	$ 39,192,802
GS 50 to 4,999 kW Legacy	0	-	-	29,018	$ -
Large Use	3978.09	1	0.1417	82,809	$ 59,471
Unmetered Scattered Load	14.35	2,121	0.0142	8,195,169	$ 481,521
Sentinel Lighting	2.08	142	8.6990	1,750	$ 18,763
Street Lighting	0.87	63,805	4.4213	126,683	$ 1,226,224
Total					$ 120,325,951

Note: Above rates exclude Smart Meter adder, Low Voltage and Transformer Allowance adders

Rates are taken from Exhibit I-1-1, table 2 before addition of the Smart Meter adder to the fixed rate, and the Low Voltage and Transformer Allowance adders to the variable rate.

This compares with the Revenue Allocated to each class from the Cost Allocation worksheet (see response to question 50 above) with small differences due to rounding of fixed rates to 2 decimal places and variable rates to 4 decimal places.

c) The transformer allowance cost was treated as a proxy for the amount of transformation cost avoided by PowerStream. This cost was added back to the base rates for the Large Use and GS>50 classes. As these classes receive the same transformer allowance, we calculated the amount to be added to rates as the total transformer allowance divided by the total kWhs billable for both classes.

d) The transformer allowance was not included in the cost allocation model. Only actual costs were allocated based on the use of PowerStream's assets. An adder for the transformation cost not in rates was calculated and added to rates as explained in part (c) above. The alternative proposed of determining a specific transformer allowance rate adder for the Large Use class has merit.

e) This was averaged over both the classes receiving the transformer allowance resulting in an adder to rates of 0.2483 per kW.

Table VECC 51-2: Transformer Allowances

Class	kWs	Transformer Allowance	Adder
GS>50 kW	10,189,730	$(2,501,412)	(0.2455)
Large Use	82,809	$ (49,685)	(0.6000)
Total/Average	10,272,539	-2,551,097	(0.2483)

As discussed in part (d) above, calculating the rate adder for transformation allowance separately, as an alternative has merit. This would result in a change from $0.2483 per kW for both classes to $0.2455 per kW for the GS>50 kW class and $0.6000 for the Large Use class.

Vulnerable Energy Consumers Coalition – Interrogatory #52

LRAM/SSM

Question:

References: **Exhibit I/Tab2/Schedule 1, page 5**
Exhibit I/Tab 2/Scheduele 1, Table 8B, page 11 - line 1

a) **Confirm that the 2006 Co-branded Mass Market measures summarized at line 1 were OPA-funded Every Kilowatt Counts (EKC) measures, not 3rd tranche MARR-funded measures.**

b) **Explain in detail the total costs charged to/recovered from OPA for these measures relative to the costs of $292,919.00 shown at line 1 for utility program costs.**

c) **Explain why an independent audit of the results of OPA-funded CDM programs is not required. Provide a copy of the report to OPA on the 2006 EKC and Keep Cool programs.**

d) **Provide the EKC program calculator for the 2006 OPA EKC spring/summer and fall campaigns.**

e) **Provide a comparison in tabular form of the input assumptions- free ridership, cost and savings (kWh) for the OPA EKC Program calculator to those used by PowerStream to calculate its SSM and LRAM claims for 2006 for the following measures:**

- **i. CFL 11W and 13w screw in**
- **ii. P Stats (heating and cooling)**
- **iii. SLED replacement**

f) **Explain why PowerStream is eligible for an SSM of $207,447 that includes OPA-funded EKC Residential programs?**

g) **Calculate the LRAM for 2006 Residential Co-branded Mass Market measures using the OPA EKC assumptions provided in response to part (e) and compare this with the amount of $202,594 shown in Table 7B page 8 of the Exhibit.**

h) **Revise the LRAM and Rate rider calculation using the following assumptions**

- **i. No SSM available for OPA-funded 2006 programs**

ii. LRAM based on savings using 2006 OPA EKC calculator assumptions for the three measures listed in part e) above

Response

a) Please refer to response to Staff - 73 (c).

b) Please refer to response to Staff - 73 (c).

c) PowerStream did not conduct an independent audits for the reasons outlined in response to Staff - 73 (c).

d) Please see Schedule VECC 52-1 and Schedule VECC 52-2.

e) This question is not applicable because PowerStream used the OPA EKC Calculator.

f) Please refer to response to Staff - 73 (c).

g) The results provided in the pre-filed evidence are calculated based on the OPA EKC assumptions.

h)(i) The answer cannot be provided in a timely fashion or with reasonable effort. Please refer to response to Staff - 73 (c).

(ii) The 2006 OPA EKC assumptions are those provided by the OPA EKC calculator. Any further calculations would provide identical results.

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Vulnerable Energy Consumers Coalition – Interrogatory #53

Question:

References: Exhibit I/Tab2/Schedule 1, page 5
Exhibit I/Tab 2/Schedule 1, Tables 7C and 8C line 1 /2

Preamble: The Board's Guidelines for ED CDM state:

7.3 (page 26)

LRAM

"The input assumptions used for the calculation of LRAM should be the best available at the time of the third party assessment referred to in section 7.5. [emphasis added]

For example, if any input assumptions change in 2007, those changes should apply for LRAM purposes from the beginning of 2007 onwards until changed again".

a) For the 2007 Co-Branded Mass Market residential program listed in Tables 7C and 8C, indicate in detail why PowerStream did not participate in the OPA Every Kilowatt Counts (EKC) campaigns for the comparable measures (e.g. CFL distribution)?

b) Why did PowerStream proceed with CFL distribution even though the net TRC was negative (per Table 8C)?

c) Provide a Copy of the 2007 EKC calculator issued by OPA for its campaigns.

d) For 2007 Residential Programs funded by PowerStream, provide a Schedule that compares the Free ridership, unit Energy Savings (kWh and kW) and measure life assumptions used by PowerStream to the OPA 2007 Every Kilowatt Counts (EKC) Calculator for its 2007 campaigns.

i) CFL 11W and 13w screw in
ii) P Stats (heating and cooling)

e) Compute the gross and net savings using OPA 2007 EKC Calculator assumptions and compare the result to the equivalent savings shown in Tables 7C and 8C.

f) Revise the 2006 and 2007 LRAM and rate rider calculations using the 2007 OPA EKC calculator savings assumptions for the Co-branded Mass Market measures listed in Table 3. Take into account the carrying charges as calculated in Table 6.

Provide the result in the form of revised Tables 3 and 1.

Response

a) PowerStream participated in the OPA Every Kilowatts Counts campaign in 2007, however the program was fully funded by the OPA in that year and as such PowerStream did not play a central role and is not seeking to recover SSM or LRAM. Therefore the campaign does not appear in the tables 7C and 8C used to calculate SSM and LRAM.

b) The TRC calculations were positive in 2005 and 2006. Despite the small negative TRC estimates for 2007, PowerStream decided to continue the program for an additional year to complete the 3rd tranche funding allocated to the program as approved by the OEB. Given the negative TRC in 2007 the resulting SSM is -$8,123 (see Exhibit I-2-1 Table 8C).

c) There is no 2007 EKC calculator available. The OPA did not issue a 2007 EKC calculator because in 2007 the program was fully funded and run by the OPA.

d) See c) above.

e) See c) above.

f) See c) above.

Vulnerable Energy Consumers Coalition – Interrogatory#54

SMART METERS

Question:

Reference: Exhibit I/Tab3/Schedule 2, page 2 Table 1

a) Confirm that the Board approved Weighted Average Cost of Capital (Exhibit F Tab1 Schedule 2, pg 5) and Working Capital allowance(s) were used to derive the SM return on Rate Base and revenue requirement for 2006 and 2007. If not see part b).

b) Provide the details of the calculation of Return on Rate base and Revenue requirements for 2006 and 2007

c) Provide the details of the calculation of Carrying costs

Response

a) Yes the Board Approved Weighted Average Cost of Capital and Working Capital allowance(s) were used.

b) See part (a) above.

c) See the response to Staff - 16.

Vulnerable Energy Consumers Coalition – Interrogatory #55A

Question:

Reference: Exhibit I/Tab 3/Schedule 3, pages 1-10 Sheets 2-6

a) Provide the 2008 Actual # meters installed and capital cost.

b) If materially different from the 57,000 forecast, please update Sheets 2-6 to reflect 2008 actuals and revised 2009 and 2010 Forecasts.

c) Provide the Calculation of the $1.04 Future Cost Offset rate adder taking into account any changes resulting from 2008 actuals.

Response

a) In 2008 PowerStream installed 53,262 Smart Meters at a capital cost of $6,517,000.

b) The 2008 Actual installations are not materially different from the forecast of 57,000 meters and capital cost of $6,994,000 a difference of $477,000 or 6.8%.

c) See Schedule VECC 55A-1 for the updated Smart Meter Rate Calculation model. The revised monthly Smart Meter adder is $1.02.

Vulnerable Energy Consumers Coalition – Interrogatory #55B

GENERAL

Question:

Reference: Exhibit I/Tab6/Schedule 3, page 3

a) Based on a recent 12 consecutive months of actual billing data, please indicate the percentage of total residential customers that:

- **Consume less than 100 kWh per month**
- **Consume 100 -> 250 kWh per month**
- **Consume 250 -> 500 kWh per month**
- **Consume 500 -> 750 kWh per month**
- **Consume 750 -> 1000 kWh per month**
- **Consume 1000 –> 1500 kWh per month**
- **Consume > 1500 kWh per month**

Response

Based on 2008 actual data (January 2008 –December 2008), the required information is presented in the table below.

Table VECC 55-1 2008 Residential customers – by consumption level, %

consumption level, kWh	% of total
0 to 100	0.1%
100 to 250	0.3%
250 to 500	2.4%
500 to 750	8.4%
750 to 1000	15.7%
1000 to 1500	36.0%
1500 and higher	37.1%
Total	100.0%

Vulnerable Energy Consumers Coalition – Interrogatory #56

Question:

Reference: Exhibit G/Tab1/Schedule 2, page 1-4

a) **Please provide a schedule that sets out the all corrections to the Application and changes PowerStream has agreed to as result of the Interrogatory process. For each, please indicate how it will impact each of the following:**

- **Fixed Asset portion of Rate Base**
- **Working Capital portion of Rate Base**
- **Weighted Average Rate of Return (%)**
- **Total Return ($)**
- **Amortization**
- **PILS**
- **OM&A**
- **Service Revenue Requirement**
- **Base Revenue Requirement**
- **Revenue Deficiency**

b) **Based on the response to part (a), please update the 2009 values for Tables 1-4.**

Response

PowerStream is not able to update the application before parties agree that any changes need to be done. Currently, we are aware of one change that is required – an update to the Cost of Capital parameters per the February 24, 2009 OEB letter.

The calculation of Base Revenue requirement, corresponding to the new Cost of Capital Parameters, is shown in the table below. This is an updated version of Table 1, in Exhibit G-1-2. Refer to response VECC-28A for cost of capital update.

Table VECC 56-1: Revenue Requirement

REVENUE REQUIREMENT

	Board Approved	Historic Actual		Bridge Year	Test Year
	2006	2006	2007	2008	2009
					$
Rate Base	440,635,822	445,146,537	462,751,532	494,574,363	533,832,432
x Cost of Capital	7.30%	7.29%	7.28%	6.94%	6.56%
Return on Ratebase	**32,151,589**	**32,467,590**	**33,700,483**	**34,338,567**	**35,003,663**
Operations, Maintenance and Administration	38,282,888	38,794,503	42,665,227	39,649,381	45,098,300
Depreciation and Amortization	26,562,678	28,166,523	29,885,078	33,045,707	36,539,557
Distribution Expenses	**64,845,566**	**66,961,026**	**72,550,304**	**72,695,088**	**81,637,858**
Revenue Requirement Before Income Taxes	**96,997,154**	**99,428,617**	**106,250,787**	**107,033,655**	**116,641,520**
Income Taxes	**11,350,483**	**9,932,216**	**10,996,391**	**7,646,757**	**8,488,068**
SERVICE REVENUE REQUIREMENT	**108,347,637**	**109,360,833**	**117,247,178**	**114,680,412**	**125,129,589**
LESS:					
Revenue Offsets:					
Board Approved Charges					
Specific Service Charges (From *Specific Service Charges* sheet)	2,428,383	2,612,980	2,593,600	2,619,334	2,621,919
Late Payment Charges (from *Summary Fin. Info* sheet)	1,030,530	1,665,845	1,700,463	1,756,000	1,834,000
Other Distribution Revenue (from *Other Distrib Revenue* sheet)	1,012,033	981,696	915,435	935,250	954,255
Other Income & Deductions (from *TB* sheet)	1,625,403	1,761,431	2,186,779	2,087,119	1,157,873
TOTAL REVENUE OFFSETS	6,096,348	7,021,952	7,396,277	7,397,703	6,568,047
Base Revenue Requirement	**102,251,289**	**102,338,881**	**109,850,901**	**107,282,709**	**118,561,542**

To: All Directors and Managers

Date: June 6, 2008

From: Lucy Lombardi, Director, Corporate Finance

Cc: John Glicksman, EVP & CFO
Dennis Nolan, EVP Corporate Services and Secretary
Milan Bolkovic, EVP & COO
Ed Chatten, VP, Corporate Performance

Subject: **2009-2010 OM&A Budget Input Guidelines**

Introduction

The 2009-2010 OM&A Budget process officially begins today! This earlier timeframe allows the Corporation to adhere to its Corporate Strategic Planning Cycle and to support our Rate Application filing process. In August, PowerStream will file our 2009 Rate Application with the OEB based on a 'forward test year'. Accordingly, PowerStream's 2009 internal budget must be aligned exactly with information filed with the OEB.

In order to meet the 2009 OM&A targets and prepare for potential reduction in total OM&A expenditures imposed by the OEB, all Directors and Manager are required to review their departmental OM&A costs prudently and prepare **a list of possible budget cuts.**

The Timelines for the 2009-2010 Budget submission is provided below. The Financial Services Team has pre-scheduled sessions with each Director/Manager to review departmental budget inputs for OM&A (both headcount and discretionary expenditure related) to ensure that the financial targets are met and 'cut lists' are completed. The **Budget Calendar is referenced as Appendix B.**

The Budget Guidelines have assumed that headcount remains flat to the approved 2008 FTE budget level. The current staffing levels are under review by HR and the EMT. Should additional headcount requests be approved by the EMT, the Budget Guidelines will be adjusted accordingly. The 2006 and 2007 OM&A actual expenditures along with 2008 year-to-date results will be provided to you as reference material in assisting you with determining your budget input. The **2009-2010 Budget Methodology is outlined in Appendix A.**

Please direct any budget related questions to Geri Yin or Grace Anlian, in our Financial Services Team. The Finance Team thanks you in advance for your commitment to adhering to our timelines indicated below. These will be adhered to without exception.

Timeline 2009-2010 Budget Submission

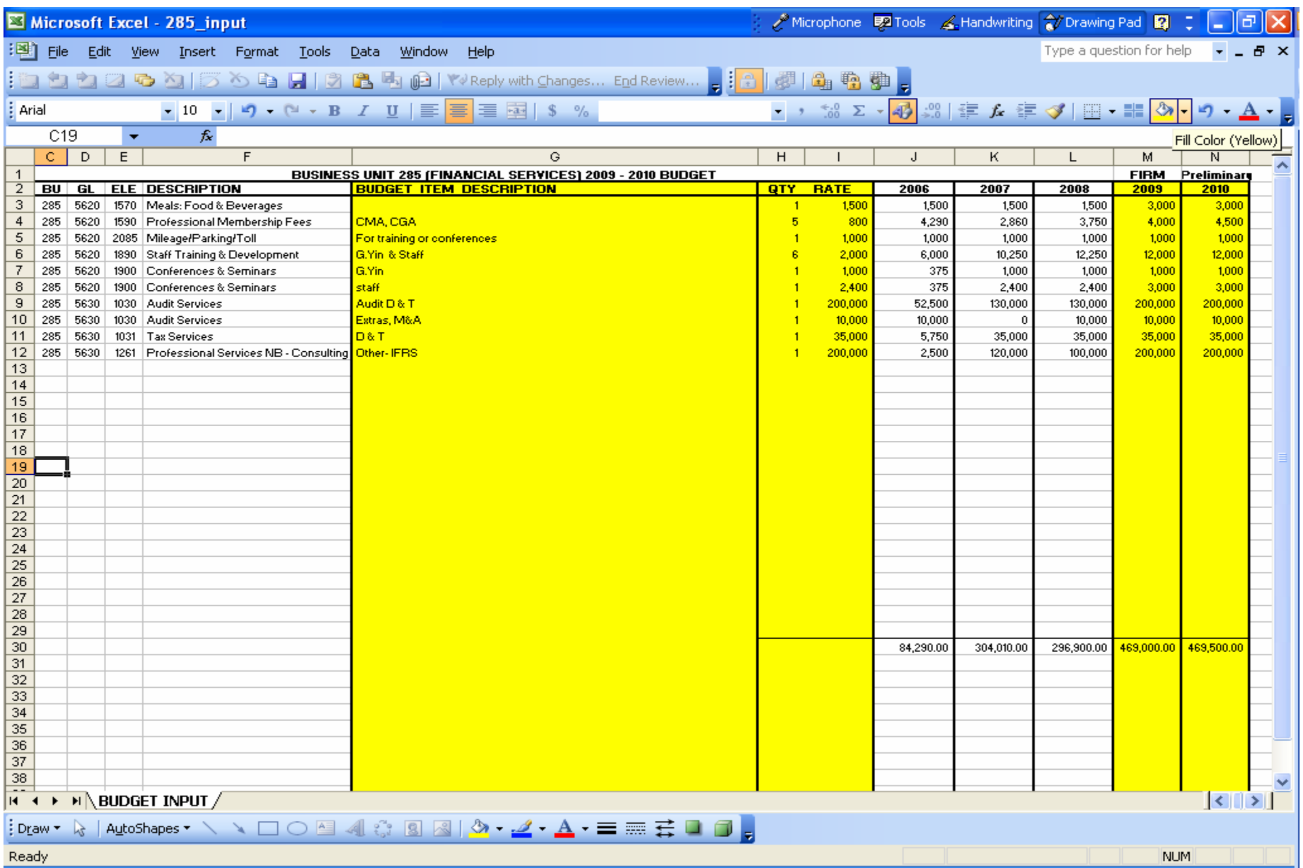
Date	Requirements	Responsibility
June 13	**Budget Request Forms/Equipment Schedule (IT, Fleet and Procurement) due to Financial Services**	**Each BU Director**
June16-July 24	Input and Review OM&A and Payroll budget with Directors/Managers. Offer up list due.	Budget Team/BU Directors
July 25	**Cut-off departmental 2008/2009 OM&A budget input**	**Each Department Manager**
August 5	Completion draft Unit, Division and Departmental budget report packages	Budget Team
August 6-22	Corporate Finance review to meet overall financial target	Corp Finance
September 6	Budget update for Audit & Finance Committee approval	Corp Finance
October 01	Final 2009/2010 OM&A budget due	Corp Finance
October 15	EMT approval 2009/2010 budget	EMT

OM&A Template

The 2009-2010 OM&A budget templates for each Business Unit/Department are located on the shared drive (**K:**) under **09_Budg** and the applicable Parent Business Unit folder. For instance, Business Unit 285 is located at:

common on 'Psfs1' (K:)\ 09_Budg\200_Finance\285\285_input

In the OM&A template, there are three files **285_Input, 285_OMA_2008 and 2006_2007 Data Reference.** The Input file provides 2006-2008 budgets. Please provide updated budget for 2009 and estimate for 2010 in the columns highlighted in yellow. The 2006-2007 actual/budget results and 2008 year-end forecast are provided in the 2006_2006 Data Reference and 285_OMA_2008 files respectively for your reference. Please refer to the screenshot illustration below. If have any question related to the templates or you don't currently have access to the K: drive, please contact Grace Anlian at Financial Services.



	C	D	E	F	G	H	I	J	K	L	M	N
1	BUSINESS UNIT 285 (FINANCIAL SERVICES) 2009 - 2010 BUDGET										FIRM	Preliminary
2	BU	GL	ELE	DESCRIPTION	BUDGET ITEM DESCRIPTION	QTY	RATE	2006	2007	2008	2009	2010
3	285	5620	1570	Meals: Food & Beverages		1	1,500	1,500	1,500	1,500	3,000	3,000
4	285	5620	1590	Professional Membership Fees	CMA, CGA	5	800	4,290	2,860	3,750	4,000	4,500
5	285	5620	2085	Mileage/Parking/Toll	For training or conferences	1	1,000	1,000	1,000	1,000	1,000	1,000
6	285	5620	1890	Staff Training & Development	G.Yin & Staff	6	2,000	6,000	10,250	12,250	12,000	12,000
7	285	5620	1900	Conferences & Seminars	G.Yin	1	1,000	375	1,000	1,000	1,000	1,000
8	285	5620	1900	Conferences & Seminars	staff	1	2,400	375	2,400	2,400	3,000	3,000
9	285	5630	1030	Audit Services	Audit D & T	1	200,000	52,500	130,000	130,000	200,000	200,000
10	285	5630	1030	Audit Services	Extras, M&A	1	10,000	10,000	0	10,000	10,000	10,000
11	285	5630	1031	Tax Services	D & T	1	35,000	5,750	35,000	35,000	35,000	35,000
12	285	5630	1261	Professional Services NB - Consulting	Other- IFRS	1	200,000	2,500	120,000	100,000	200,000	200,000
30								84,290.00	304,010.00	296,900.00	469,000.00	469,500.00

Note: You will only be able to make changes to the columns highlighted in yellow. The prior 2009 budget figures need to be reviewed for budget reduction purpose. The updated 2009 budget should be entered under FIRM 2009 column. The estimate of 2010 should be populated under PRELIMINARY 2010 column.

The cut-off date for departmental OM&A input is Tuesday, July 25th.

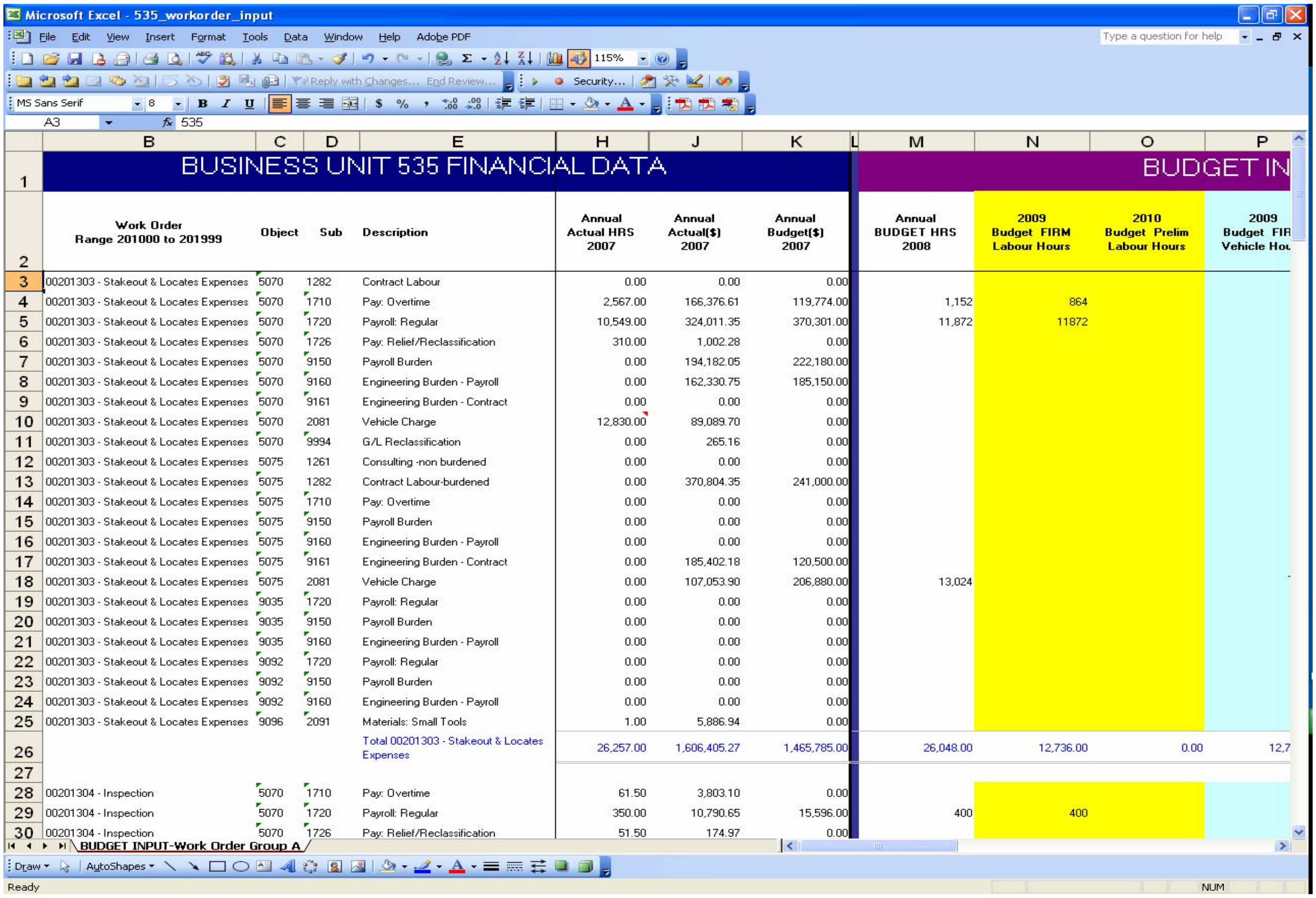
OM&A-Payroll

The payroll budget includes staffing costs and related burdens. The departmental headcounts, annual hours, hourly rate and vacation allotment, etc. will be input directly by Financial Services in conjunction with HR. The staffing level is based on the approved 2008 budget. There will not be any new staff budgeted in 2009/2010 unless approved by the EMT. For budget purposes, the salary increase is set at 3.0% across the board for both union and non-union staff. The payroll burden rates have been adjusted from 2008 budget. Appendix A outlines all 2009 Burden Rates.

The departmental OM&A-Payroll budget for 2009/2010 will be completed by the Financial Services Budget team/HR and reviewed with each Business Unit director during the period from July 7th to 25th.

OM&A-Work Order

For Group/Outside A Business Units including Linemen, Inspection, Labourers, Electrical, Metering, Protection & Control (BU 445, 475, 485, 535 and 575), the budgets are done at the work order level. In addition to the OM&A Template described above, these Business Units are required to provide detailed budgets including hours, material, contracts, etc. for each active work order. A sample of the Budget Input-Work Order template is presented below.



	B	C	D	E	H	J	K	M	N	O	P
1	BUSINESS UNIT 535 FINANCIAL DATA							BUDGET IN			
2	Work Order Range 201000 to 201999	Object	Sub	Description	Annual Actual HRS 2007	Annual Actual($) 2007	Annual Budget($) 2007	Annual BUDGET HRS 2008	2009 Budget FIRM Labour Hours	2010 Budget Prelim Labour Hours	2009 Budget FIR Vehicle Hou
3	00201303 - Stakeout & Locates Expenses	5070	1282	Contract Labour	0.00	0.00	0.00				
4	00201303 - Stakeout & Locates Expenses	5070	1710	Pay: Overtime	2,567.00	166,376.61	119,774.00	1,152	864		
5	00201303 - Stakeout & Locates Expenses	5070	1720	Payroll: Regular	10,549.00	324,011.35	370,301.00	11,872	11872		
6	00201303 - Stakeout & Locates Expenses	5070	1726	Pay: Relief/Reclassification	310.00	1,002.28	0.00				
7	00201303 - Stakeout & Locates Expenses	5070	9150	Payroll Burden	0.00	194,182.05	222,180.00				
8	00201303 - Stakeout & Locates Expenses	5070	9160	Engineering Burden - Payroll	0.00	162,330.75	185,150.00				
9	00201303 - Stakeout & Locates Expenses	5070	9161	Engineering Burden - Contract	0.00	0.00	0.00				
10	00201303 - Stakeout & Locates Expenses	5070	2081	Vehicle Charge	12,830.00	89,089.70	0.00				
11	00201303 - Stakeout & Locates Expenses	5070	9994	G/L Reclassification	0.00	265.16	0.00				
12	00201303 - Stakeout & Locates Expenses	5075	1261	Consulting -non burdened	0.00	0.00	0.00				
13	00201303 - Stakeout & Locates Expenses	5075	1282	Contract Labour-burdened	0.00	370,804.35	241,000.00				
14	00201303 - Stakeout & Locates Expenses	5075	1710	Pay: Overtime	0.00	0.00	0.00				
15	00201303 - Stakeout & Locates Expenses	5075	9150	Payroll Burden	0.00	0.00	0.00				
16	00201303 - Stakeout & Locates Expenses	5075	9160	Engineering Burden - Payroll	0.00	0.00	0.00				
17	00201303 - Stakeout & Locates Expenses	5075	9161	Engineering Burden - Contract	0.00	185,402.18	120,500.00				
18	00201303 - Stakeout & Locates Expenses	5075	2081	Vehicle Charge	0.00	107,053.90	206,880.00	13,024			
19	00201303 - Stakeout & Locates Expenses	9035	1720	Payroll: Regular	0.00	0.00	0.00				
20	00201303 - Stakeout & Locates Expenses	9035	9150	Payroll Burden	0.00	0.00	0.00				
21	00201303 - Stakeout & Locates Expenses	9035	9160	Engineering Burden - Payroll	0.00	0.00	0.00				
22	00201303 - Stakeout & Locates Expenses	9092	1720	Payroll: Regular	0.00	0.00	0.00				
23	00201303 - Stakeout & Locates Expenses	9092	9150	Payroll Burden	0.00	0.00	0.00				
24	00201303 - Stakeout & Locates Expenses	9092	9160	Engineering Burden - Payroll	0.00	0.00	0.00				
25	00201303 - Stakeout & Locates Expenses	9096	2091	Materials: Small Tools	1.00	5,886.94	0.00				
26				Total 00201303 - Stakeout & Locates Expenses	26,257.00	1,606,405.27	1,465,785.00	26,048.00	12,736.00	0.00	12,7
27											
28	00201304 - Inspection	5070	1710	Pay: Overtime	61.50	3,803.10	0.00				
29	00201304 - Inspection	5070	1720	Payroll: Regular	350.00	10,790.65	15,596.00	400	400		
30	00201304 - Inspection	5070	1726	Pay: Relief/Reclassification	51.50	174.97	0.00				

The cut-off date for departmental OM&A- work order input is Friday, July 25th.

Budget Request Form/Equipment Schedules

The Budget Request Form attached below is used as a means to collect the departmental requests for IS, Fleet and Building & Facility, including both Capital and OM&A expenditures.

It is required that each director consolidates his/her business units' budget requests in these areas and submits it to "**Financial Services"** once approved.

Once received, the Financial Services Budget Team will forward it onto Tony D'Onofrio, IS (Bill Schmidt/Basil Henriques), Procurement (Rob Antenucci) and Fleet (Rick Willems) to jointly review and determine the proper input for the centralized budgets.

The Budget Request Form must be submitted by directors to Financial Services **no later than Friday, June 13th.**

The Budget Request Form is attached below.

K:\09_Payroll\
Documenation\Equipr

Appendix A 2009/2010 Budget Methodology

The 2009/2010 budget is based on the 2008 approved OM&A budgets and 2008 year-end forecast. This base is further increased to incorporate inflation, customer growth, regulatory & legal requirements. In summary, the following budget principles are applied in 2009/2010 budget process:

1. Actual/budget 2006-2007 spending were provided to each department as reference in determining the 2009-2010 budget input

2. Staff count is based on the approved 2008 budget. No further additions unless approved by EMT and the Board

3. For the Payroll budget, the followings were factored in the 2009/2010 Salary Rate:
   a. 3% Economic increase for both union and non-union staff
   b. Progression for qualified staff
   c. PIPS

4. All Management wage adjustments are budgeted to the applicable business unit

5. All Students are budgeted to the hiring business unit

6. For Group/Outside A Business Units including Linemen, Inspection, Labourers, Electrical, Metering, Protection & Control, the budgets are done at the work order level, allowing better planning, reporting and productivity & performance monitoring

7. Payroll burdens are adjusted to align with OEB requirement, i. e. overtime and PIP are removed from the scope of burdenable salary; payroll and engineering burdens currently applied to the payroll benefit pool are removed, etc.

8. The Budget Request Forms (Equipment Schedule) is used as a means to collect relevant departmental expenditures on IT, Procurement and Fleet such as

   a. Office Equipment
   b. Computer
   c. Software
   d. Vehicles
   e. Telephone and Radio

   Each director is required to consolidate the requests for his/her own business units and submit it to Financial Services who will then work with IT, Procurement and Fleet for developing respective budgets

9. The budgets will be reviewed and discussed with each Business Unit director and EVP for their endorsement

10. Various departmental budget reports are designed and available for reporting
    - **Headcount Summary and Detailed Report** by Division/BU
    - **Payroll Budget Report** by Division/BU: including Regular, OT, Payroll/Engineering Burden, PIP, Allocation to Capital and Burden Pools

- **Maintenance Work Order Report** by department: detailed labor, OT, materials, contracts, burdens, etc.
- **Hours Distribution Report** by BU: productive and non-productive hours for outside A business units
- **OM&A Grand Summary Report** by Division/BU: including payroll and other expenses by GL account and element
- **Burden Pool Summary and Detailed Report**: including Payroll, Engineering, Vehicle, Stores burden pools by Business Unit
- **Applied Burden Summary and Detailed Report**:: including applied burdens on Payroll, Engineering (Labor, Contract and Materials), Stores and Vehicles by business Unit
- **Allocation to Capital Report**: detailed amount allocated from OM&A to Capital budget

11. The Burden rates and allocation are as follows:

Payroll Burden	**Budget 2009**	**Element**	**Budget 2008**
Outside A	80%	9150	60%
Outside B	40%	9150	30%
All other	40%	9150	30%
Students	10%	9150	10%
Engineering Outside A	60%	9160	50%
Other Burdens			
Stores handling	15%	9180	15%
Vehicle	Rate applied	2081	Rate applied
Engineering on stores Material	0%	9162	20%
Engineering on Contract Labor	60%	9161	50%

Corporate Finance Budget Team

Lucy Lombardi	Head
Geri Yin	Lead
Grace Anlian	Coordinator
Sebastin Valam	Budget Resource
Nicole Fan	Budget Resource

Appendix B 2009/2010 Budget Review Calendar

The Financial Services Team has pre-scheduled sessions with each Director/Manager to review departmental budget inputs for OM&A (both headcount and discretionary expenditure related) to ensure that the financial targets are met and 'cut lists' are completed.

K:\09_Payroll\
Calendar\Dept Budge

Schedule VECC 5-2

2009 Firm Budget Grand Summary

	Gross Amount	Allocation to: Capital / CDM	Payroll Burden	Engineering Burden	Stores Burden	Vehicle Burden	NetOM & A
Board & CEO	1,074,129	101,575	0	0	0	0	972,554
105 Board of Directors	1,074,129	101,575	0	0	0	0	972,554
Executive Mgmt Group	2,646,121	631,051	0	0	0	0	2,015,069
115 Executive Management Group	2,646,121	631,051	0	0	0	0	2,015,069
Asset Management	19,069,983	238,373	2,614,253	3,326,658	0	100,363	12,790,336
405 Director - Lines	734,657	238,373	0	496,284	0	0	0
445 Lines	11,142,149	0	2,255,683	1,869,522	0	67,451	6,949,493
475 Station Maintenance	2,153,433	0	158,546	251,242	0	2,801	1,740,843
485 Protection & Control	1,856,634	0	200,024	142,063	0	30,111	1,484,436
545 Stations Design & Construction	687,547	0	0	567,547	0	0	120,000
565 System Control	2,495,564	0	0	0	0	0	2,495,564
Executive Support & Metering	2,072,195	0	412,710	436,875	0	0	1,222,610
575 Metering	2,072,195	0	412,710	436,875	0	0	1,222,610
Corporate Services	17,788,994	1,160,374	510,292	468,824	2,109,365	3,474,606	10,065,533
175 Corporate Performance	400,719	31,484	0	0	0	0	369,235
415 Health & Safety	390,292	0	390,292	0	0	0	0
425 Information & Technology	4,804,607	963,002	0	147,500	0	0	3,694,105
495 Fleet	2,354,189	0	0	0	0	2,354,189	0
605 Facilities West	1,166,362	0	0	0	275,261	664,826	226,274
615 Facilities East	925,100	0	0	0	305,283	425,546	194,271
625 Head Office	1,606,620	0	0	321,324	21,368	30,044	1,233,884
705 Directors - Corporate Services	1,211,937	122,384	0	0	217,093	0	872,459
715 Human Resources	929,711	0	0	0	0	0	929,711
725 Regulatory & Gov't Affairs	1,710,219	0	0	0	0	0	1,710,219
735 Communications	878,879	43,504	0	0	0	0	835,375
745 Purchasing	611,697	0	120,000	0	491,697	0	0
755 Stores	798,663	0	0	0	798,663	0	0
Engineering & Operations	9,134,223	0	77,186	7,308,201	0	3,289	1,745,547
505 Directors - Eng Services	436,124	0	0	436,124	0	0	0
524 GIS	273,822	0	0	273,822	0	0	0
525 Engineering Records	999,122	0	0	999,122	0	0	0
526 Engineering Planning	294,653	0	0	294,653	0	0	0

Schedule VECC 5-2

	Gross Amount	Allocation to Capital / CDM	Allocation to Payroll Burden	Allocation to Engineering Burden	Allocation to Stores Burden	Allocation to Vehicle Burden	NetOM & A
535 Engineering - Inspect. & Locate	2,800,862	0	77,186	1,017,340	0	3,289	1,703,047
555 Engineering - Design	3,053,296	0	0	3,053,296	0	0	0
556 Engineering - Administration	969,049	0	0	926,549	0	0	42,500
557 Engineering - Standards	307,295	0	0	307,295	0	0	0
Smart Grid & New System Tech	772,718	346,104	0	204,578	0	0	222,035
176 Corporate Performance-Key Account	189,419	31,484	0	0	0	0	157,935
523 Environmental Management	204,578	0	0	204,578	0	0	0
595 Conservation Demand Mgmt	378,721	314,621	0	0	0	0	64,100
Finance	19,323,244	1,902,053	0	0	0	0	17,421,191
205 Finance Directors	1,070,853	64,254	0	0	0	0	1,006,599
215 Corporate Finance	2,113,473	172,325	0	0	0	0	1,941,148
225 Customer Service - Billing	2,825,157	244,754	0	0	0	0	2,580,403
235 Customer Relations	2,016,425	456,711	0	0	0	0	1,559,713
236 Support Services	753,633	321,223	0	0	0	0	432,411
245 Business Solutions	2,553,721	34,465	0	0	0	0	2,519,256
255 CS - Payment Processing	1,173,816	24,946	0	0	0	0	1,148,870
256 CS - Collection	2,280,700	12,930	0	0	0	0	2,267,770
265 Accounting	1,859,727	375,433	0	0	0	0	1,484,295
275 Payroll	441,798	0	0	0	0	0	441,798
285 Financial Services	1,363,074	195,012	0	0	0	0	1,168,062
295 Rates	870,866	0	0	0	0	0	870,866
Corporate	9,218,565	0	8,461,405	0	0	0	757,160
815 Joint Services Revenue	-4,117,623	0	0	0	0	0	-4,117,623
995 Corporate	11,538,705	0	8,461,405	0	0	0	3,077,300
996 Capital & Property Taxes	1,797,483	0	0	0	0	0	1,797,483
Grand Total	81,100,171	4,379,531	12,075,845	11,745,136	2,109,365	3,578,258	47,212,036

POWERSTREAM INC.

2009 Budget and 2010-2013 Financial Outlook

Board of Directors Presentation

Private and Confidential

December 10, 2008

PowerStream
YOUR CURRENT CONNECTION

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2009 Budget Guidelines - Process Summary

- 2007 Actual results reviewed for comparative purposes
- 2009 rate application used as a starting point, calendarized to reflect increase in rates effective May 1
- 2009 rate application achieves allowed ROE of 8.4%
- September – Draft 2009 Budget presented to AFC and Board of Directors
- Further sensitivity analysis performed due to worsening economic conditions and possible risks identified
- December 10th – Board of Directors to approve Final 2009 Budget

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2009 Budget Guidelines

- Guidelines included:
  - 2009 budget prepared to support budget filed in rate application
  - Rate application built in 7.2% distribution revenue growth which resulted in a calendarized revenue growth of 5.9%
  - Calendarized rate increase to customer is 4.7%
  - OM&A projection from both a bottom up and top down approach
  - Rigorous bottom up process to support rate application and budget development
- Maintained budget presented at September AFC and Board meetings

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2009 Budget

($M)	2007 Actual	2008 Budget	2009 Budget Calendarized
Distribution Revenue	114.6	112.7	119.3
Other Revenue	10.4	6.6	5.0
OM&A	45.9	41.4	47.2
Depreciation	29.7	31.8	35.6
Interest Expense	14.2	16.2	17.7
Income Taxes	14.1	10.9	7.9
Net Income	21.1	19.0	15.9
Rate Base ROE	10.5%*	9.0%	7.3%
Rate Base*	462.8	527.8	542.7

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* Includes sale of excess fibre assets

2009 OM&A

	2006 Board Approved	2007 Prjctd	2008 Prjctd	2009 Prjctd
OM&A based on 3% p.a. inflation - 1% productivity + 50% of customer growth	$38.3	$39.7	$41.1	$42.6
Add:				
MDMR				0.9
Meter Reading/Maintain/Reverification				(0.8)
Apprentice Program				1.2
IFRS				0.8
Bad Debt				0.4
Capital Taxes				1.3
TOTAL				**$46.4**
Items not in Rates Application (Donations & Sponsorships, M&A)				0.8
TOTAL OM&A BUDGET				**$47.2**

PowerStream
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Net Capital Budget

($M)	2007 Actual	2008 Forecast	2009 Budget	2010 Forecast	2011 Forecast	2012 Forecast	2013 Forecast
Base Cap Ex	32.0	31.2	33.1	33.1	33.1	33.1	33.1
New TS	3.4	9.7	28.6	10.1	7.4	34.4	8.0
New HO/Ops Centre	20.2	0.0	0.4	4.9	0.0	0.0	0.0
SMART Meters *	10.2	9.3	13.0	25.3	0.0	0.0	2.7
YRRT	0.0	0.0	5.9	12.1	6.6	6.6	7.2
CIS Initiative/JDE	0.0	0.0	0.6	8.5	5.3	4.3	1.3
407 Transitway	0.0	0.0	0.0	0.0	0.0	4.0	0.0
Other	1.6	9.2	3.6	3.9	19.4	22.6	19.8
Total Capex Budget	67.4	59.4	85.2	97.9	71.8	105.0	72.1

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* SMART Meter installation to continue through 2010

5 Year Financial Outlook

($M)	Approved Budget 2008	Budget 2009	Preliminary Forecast 2010	Forecast 2011	Forecast 2012	Forecast 2013
Total Revenue	580.1	593.3	611.4	631.1	651.6	672.7
Distribution Revenue	112.7	119.3	122.9	128.1	133.5	139.2
Other Revenue	6.6	5.0	5.4	5.5	5.6	5.6
OM&A	41.4	47.2	44.5	41.5	41.0	40.2
Depreciation	31.9	35.6	36.6	40.5	44.7	47.4
Interest Expense	16.2	17.7	18.7	21.1	21.8	22.9
Prov. for Income Tax	10.9	7.9	9.1	9.3	9.2	9.9
Net Income	19.0	15.9	19.4	21.2	22.4	24.3
ROE*	9.0%	7.3%	8.4%	8.4%	8.4%	8.4%
Net Capital	77.4	85.2	97.9	71.8	105.0	72.1
Tax Rate:	33.5%	33%	32%	30.5%	29%	29%

Preliminary--→

PowerStream YOUR CURRENT CONNECTION

*Based on OEB prescribed method of calculating Return on Equity

Risks to 2009 Budget

- Rate base subject to rate filing acceptance
- Revenue requirement subject to possible disallowed items
- Approved rate application ROE at less than 8.4% leads to revenue shortfall
- Potential weakening economy and customer growth not achieved at 3.2%
- Rate implementation delayed to June 1, 2009
- Budgeted distribution revenue based on stable weather pattern; risk of warmer winter and cooler summer
- Energy conservation pressure on distribution revenue
- Potential fluctuation in interest rates resulting in increased interest expense
- Property tax higher than budgeted due to new building tax assessment

Conclusion

- Growth and diversified customer base provide some protection against the economic down turn and help to favourably influence achievement of Distribution Revenue

- The corporation will continue to examine process improvements and opportunities for reductions in OM&A across the organization

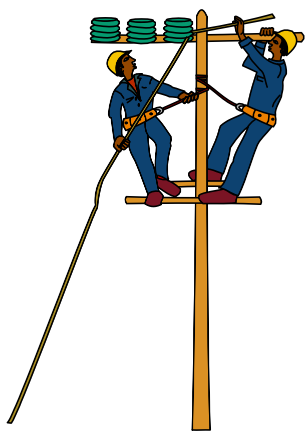
- The merger with Barrie Hydro provides an opportunity for better financial returns

- The OEB review process for the 2009 rate application will be effectively managed by staff, so that the applied-for revenue is provided on May 1, 2009

PowerStream
YOUR CURRENT CONNECTION

Distribution System Planning Report

2007



ENGINEERING PLANNING
DECEMBER 2007

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POWERSTREAM MISSION STATEMENT

To deliver reliable power and related services safely and efficiently to support our customers' quality of life and to provide value to our shareholders.

POWERSTREAM VISION STATEMENT

We will be an innovative and socially responsible leader in power distribution and related services in Ontario.

EXECUTIVE SUMMARY

The 2007 PowerStream Distribution System Planning Report (DSPR) provides information on PowerStream's planning processes and the short term plans for system augmentation for the period 2008 – 2012. The Report also provides a longer term forward looking vision of capital replacement/refurbishment expenditures through the application of PowerStream's Asset Condition Assessment model that balances the risk of asset failure with cost of mitigation. It further addresses some potential future initiatives for enhanced planning methodologies.

PowerStream continues to experience a high level of growth. System Peak demand is expected to grow at a rate of approximately 4% annually over the 2008-2012 time period. Growth is one of the major drivers for the short term capital augmentation expenditures. The largest key expenditure required to service new growth is a new transformer station expected to be in service in 2009. The majority of the $20 million cost of the station proper will be spent in the 2008 – 2009 time frame, with a staged feeder connection plan from 2008-2011.

Reliability driven projects have been established to, as a minimum, maintain current levels of service to customers compared to the previous 3 year moving averages of SAIDI, SAIFI and CAIDI. Feeders with deteriorating reliability statistics (reliability indices or outage statistics) are targeted for review and remedial action plans are developed to improve reliability statistics. In 2008, the focus will continue on implementing measures to ensure our planning philosophy guidelines are adhered to including the purchase of two spare transformers for each of the transformer station types. Reliability measures will be addressed through the continued refinement and development of the Asset Condition Assessment program, feeder reconfiguration and balancing, radial feeder supply remediation, distribution automation, improved design reviews for customer connections, participation on the smart grid initiative and monitoring of new reliability indices such as ASAFI and ASIDI. Capacity measures are addressed through feeder upgrades and the ongoing work to construct the next transformer station and associated feeders for a 2009 in-service date.

Other capital expenditures are driven externally by regulatory or grid authority directives such as the installation of a capacitor bank at TS2 in Vaughan.

For the longer term, capital expenditures will be augmented through a detailed application of our Asset Condition Assessment model. In 2007, Phase II applied the ACA model to our Municipal Station Power Transformers, circuit breakers and underground cable. Current indications are that planned replacement/refurbishment of the municipal station transformers will not be required until 2023. In 2008, the Phase II models will be refined, and Phase III will be applied to our remaining major asset classes

The forecasts for the 2008-2012 financial requirements are shown in Table 1.

TABLE 1: SUMMARY OF TOTAL RECOMMENDED 2008-2012 CAPITAL DOLLARS

(all $ in 000)

A) Planning

Category	2008 BUDGET $000	2009 BUDGET $000	2010 BUDGET $000	2011 BUDGET $000	2012 BUDGET $000
Special Projects	4,891	8,200	9,900	8,925	12,900
Reliability Projects	3,201	5,452	5,278	3,928	4,780
Capacity Projects	6,570	32,506	3,900	7,323	22,562
TOTAL DOLLARS	**$14,662**	**$46,158**	**$19,078**	**$20,176**	**$40,242**

B) Station Design

Category	2008 BUDGET $000	2009 BUDGET $000	2010 BUDGET $000	2011 BUDGET $000	2012 BUDGET $000
Special Projects	$1,932	$415	$295	$1,026	$143
Reliability Projects	$2,045	$277	$418	$2,912	$409
Capacity Projects	$7,720	$11,285	$1398	$4,519	$17,820
Unplanned Projects	$0	$0	$0	$0	$0
TOTAL DOLLARS	**$11,697**	**$11,977**	**$2,111**	**$8,097**	**$18,372**

Category	2008 BUDGET $000	2009 BUDGET $000	2010 BUDGET $000	2011 BUDGET $000	2012 BUDGET $000
Special Projects	$1,932	$415	$295	$1,026	$143
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Capacity Projects	$7,720	$11,285	$1398	$4,519	$17,820
Unplanned Projects	$0	$0	$0	$0	$0
TOTAL DOLLARS	**$11,697**	**$11,977**	**$2,111**	**$8,097**	**$18,372**

	2008	**2009**	**2010**	**2011**	**2012**

Category	BUDGET $000	BUDGET $000	BUDGET $000	BUDGET $000	BUDGET $000
Special Projects	$1,932	$415	$295	$1,026	$143
Reliability Projects	$2,045	$277	$418	$2,912	$409
Capacity Projects	$7,720	$11,285	$1398	$4,519	$17,820
Unplanned Projects	$0	$0	$0	$0	$0
TOTAL DOLLARS	**$11,697**	**$11,977**	**$2,111**	**$8,097**	**$18,372**

It is expected that the proposed capital program will accommodate growth needs and maintain current levels of service reliability to customers in conjunction with an effective annual maintenance program. See Appendices 3 & 4 for detailed description of the various projects.

1.0 INTRODUCTION

1.1 Purpose

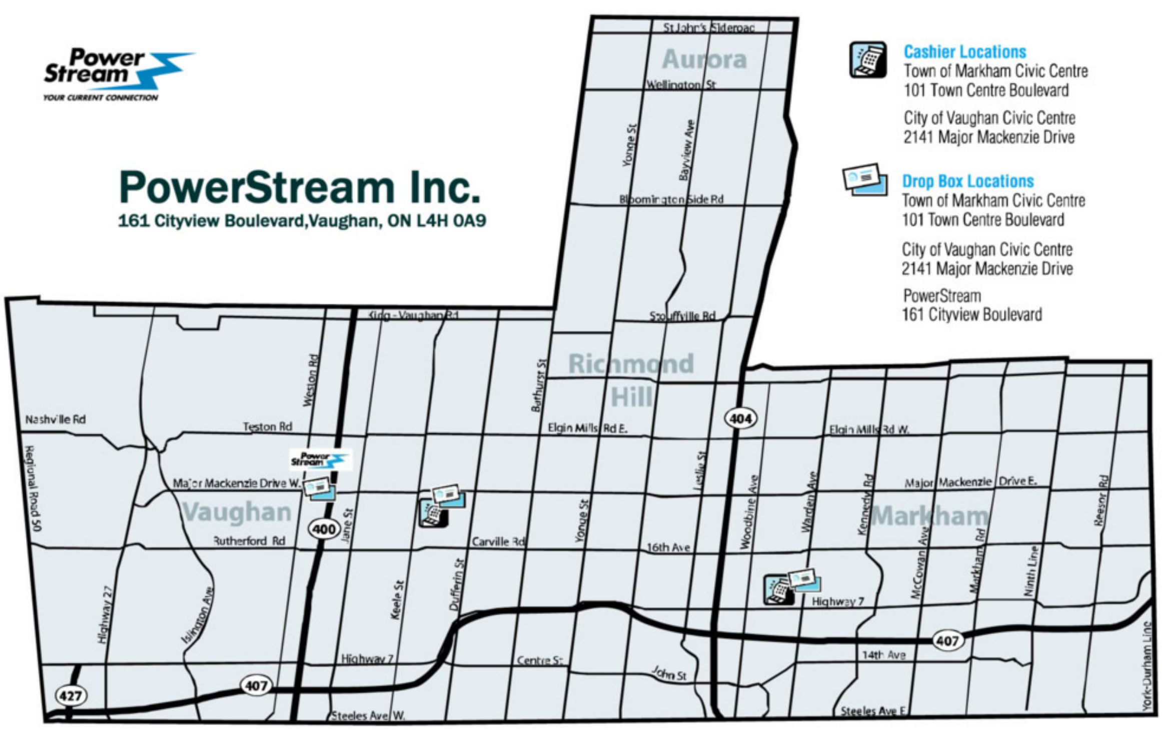
The 2007PowerStream Distribution System Planning Report (DSPR) provides information on the planning processes that are in place to ensure the ongoing successful operation of the distribution system. Specific outcomes of this report are designed to:

- Provide support for the corporate mission and vision statements and current key initiatives;
- Facilitate the efficient development of the distribution system to satisfy customer demand and reliability needs through a 10 year load growth horizon;
- Provide a forward looking view of expected capital and distribution related OM&A expenditures to support PowerStream's regulatory rate submission cases;
- Identify short term period constraints and associated capital solutions for annual or multi-year budget preparation;
- Comply with regulatory/legal obligations (if any) to report on PowerStream's asset management plans and processes.

2.0 PLANNING INFORMATION

2.1 Infrastructure

PowerStream is one of the largest local electricity distribution companies in Ontario, providing service to over 230,000 residential and business customers in the municipalities of Aurora, Markham, Richmond Hill and Vaughan (see map below) through a mix of 28kV and 44kV distribution infrastructure.



Fast Facts – December 31, 2006

Assets

One of the largest electricity distribution systems in Ontario with distribution assets valued at:	$579 million
Distribution system consisting of -	
overhead circuit wires:	1,854 km
underground cable:	4,075 km
Transformer stations:	10
Municipal substations:	17
Transformers:	29,783
Switchgear:	1,367
Poles and pole structures:	32,073
Billing meters:	225,914

Customers

Total (municipalities of Aurora, Markham, Richmond Hill and Vaughan)	228,666
Residential:	200,794
Commercial under 50 kW demand:	24,027
Commercial over 50 kW demand:	3,644
Large industrial user:	6
Sentinel lights:	148
Street lighting:	47

Service Area

Geographical size of service territory:	640.2 km^2

Distribution of Electricity

Total electricity billed in 2005:	6,801GWh
2006 system peak demand:	1,577 MW
All-time system peak demand:	1,577 MW
Average annual electricity consumption billed in 2006 -	
Residential - per customer:	10,037 kWh
Commercial - per customer:	161,041 kWh

Employees **353**

2.2 Engineering Planning and Stakeholder Interests

The Engineering Planning Department is responsible for the long term development of the distribution system.

The planning objective is to determine the optimum level of investment in distribution capacity and the optimum configuration of the distribution system

These objectives are accomplished by having due regard to:

- corporate objectives;
- stakeholder interests;
- relative costs and benefits associated with alternative distribution development strategies;
- acceptable levels of risk;
- environmental factors that directly or indirectly impact on the efficient and reliable operation of the distribution network;
- defensible processes for the selection of capacity and reliability related projects.

In carrying out distribution activities to support the Corporate Mission and Vision statements, stakeholder interests have to be considered and factored into the short and long range planning processes. Stakeholder interests vary and at times can be either complementary or conflicting. As a part of the planning process, assumptions are made about the stakeholder interests. The assumptions and related stakeholder interests are shown in Table 2 below:

Table 2 – Stakeholder Interests

Stakeholders	Stakeholder Needs	Stakeholder Interests	Stakeholder Perception of Planning Risks
PowerStream Corporation	Accurate external/internal information to set policy	Achieve mission vision and objectives	Financial loss due to sub-optimization of operations; brand value deterioration
Shareholders	Stable rate of return	Safe long term investment	Financial and political pitfalls
OPA	Accurate load forecasting	Comprehensive utility forecasting process	Inaccurate information contribution to the IPSP
IESO	Accurate real-time information and market rule compliance by market participants	Utility adherence to technical and communication protocols	Inaccurate or untimely information for SIA
HONI	Activity coordination	Coordination of transmission and distribution growth needs	Inaccurate forecasts affecting resource commitments
Generators	Stable market and ability to connect to distribution system	Clear rules and processes for connection	Distribution congestion affecting plant location and costs
Retailers	Reliable supply to customers	Maximize contract revenues	Loss of revenue
Provincial Government	Efficient, low cost and reliable market	Reliable supply to stimulate growth and political goodwill	Localized negative political impact
OEB	Efficient, low cost and reliable market; regulatory compliance	Minimization of regulatory intervention	Regulatory intervention and political decision risks
Municipalities(non-shareholders)	Reliable supply to customers	Consultations on activities within municipal boundaries; visual aesthetics	Supply/reliability shortfalls affecting their constituents
Residential Customer	Reliable supply and low rates	Aesthetics	Supply/reliability shortfalls; price concerns
Small Commercial	Reliable supply and low rates	Rate stabilization or reduction	Supply/reliability shortfalls; price concerns affecting business plans
Large Commercial/Industrial	Reliable supply and low rates	Rate stabilization or reduction	Supply/reliability shortfalls; price concerns affecting business plans

2.3 Planning Process

2.3.1 General

Distribution System Planning can be defined as a rational process comprising field measurements and analytical activities, which collectively ensure that specifications and authorization, including appropriate lead times, are available for the most economic expansion and modification of the distribution system to meet the electrical supply requirements of customers.

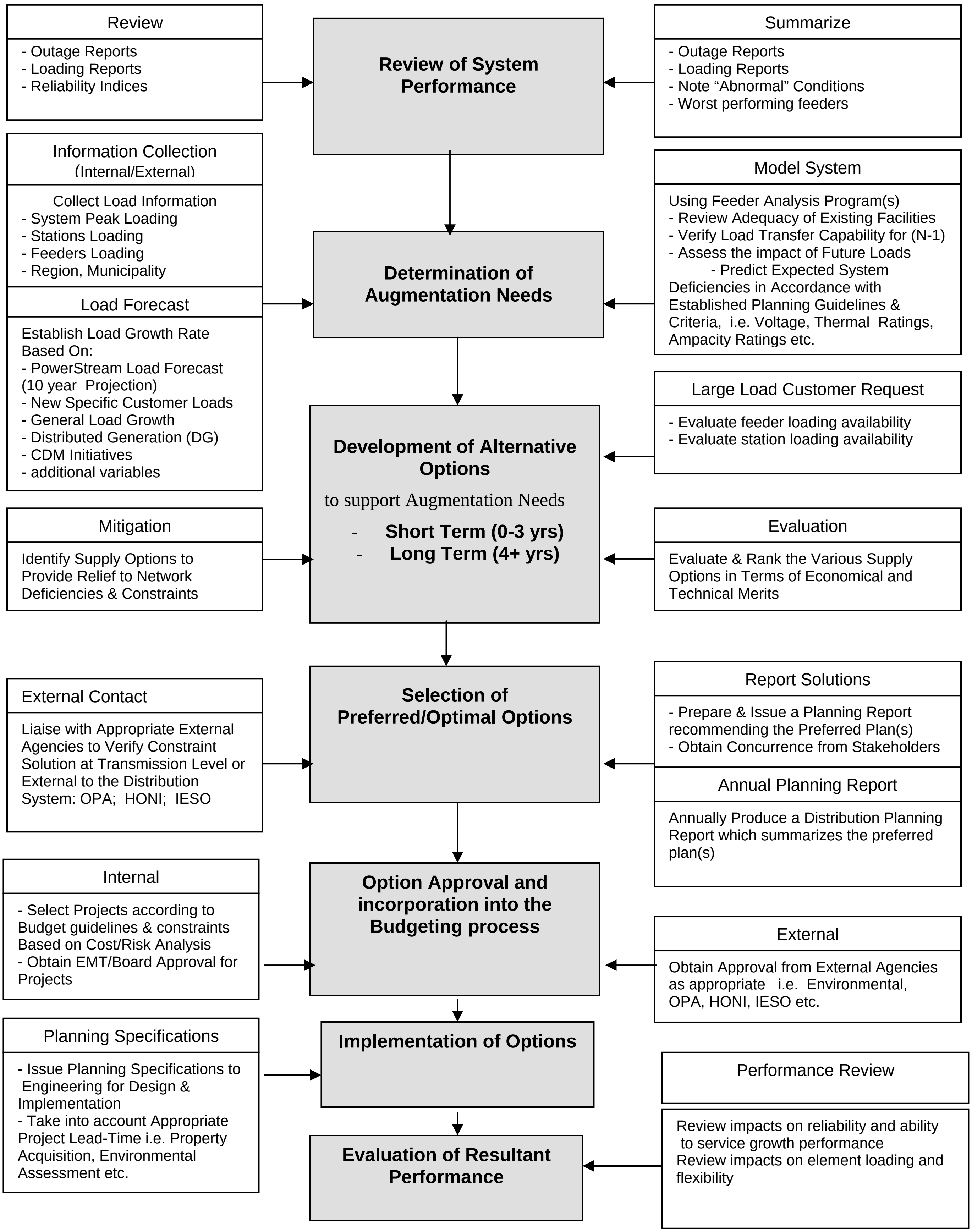
It should also be noted that Distribution Planning is a year round process. Issues of growth and reliability are evaluated on an ongoing basis to determine optimal solutions that feed into the annual budgeting process. Solutions incorporate corporate and stakeholder interests.

The typical planning cycle consists of seven steps:

1. Review of System Performance
2. Determination of Augmentation Needs
3. Development of Alternative Options to support Augmentation Needs
4. Selection of preferred/optimal options
5. Option Approval and Incorporation into the Budgeting process
6. Implementation of Options
7. Evaluation of Resultant Performance

The Planning process as practiced at PowerStream is summarized in Figure 2:

Figure 1 – Distribution System Planning Process



2.3.2 Annual Studies and Reports

Each year, System Planning studies the performance of the distribution system, from the previous year and prepares a:

- "Load Balancing & System Reconfiguration Plan" for PowerStream South (27.6kV system)
- "Load Balancing & System Reconfiguration Plan" for PowerStream North (44kV and 13.8kV systems)
- Studies for anomalies in the distribution system, such as radial supplies or poorly performing segments of the system.

As a result of these studies, capital projects may be suggested for submission to the budget.

2.4 Planning Philosophy

PowerStream's Planning philosophy was developed through a multi-step process review and analysis of industry best practices in this area. The Planning Philosophy covers activities relating to:

- Distribution Design
- Distribution Capacity Planning
- Distribution Risk Assessment
- Distribution Reliability Planning

Specific steps can be seen in the Board approved Planning Philosophy Report.

2.4.1 Distribution Design

Nearly all loads, within PowerStream's service area, are supplied from Dual Element Spot Network (DESN) transformer stations either owned by PowerStream or Hydro One Networks Inc.

The 27.6/16kV distribution feeders are in an "open grid design" arrangement whereby multiple feeders traverse a distribution area with multiple interconnections between the feeders at various normal open points. In the event of a fault on a feeder or loss of supply to a particular feeder, adjacent feeders have the ability to pickup supply to customers after operator intervention.

2.4.2 Distribution Capacity Planning and Risk Assessment

Although there are two alternative approaches to distribution planning - *deterministic* and *probabilistic,* PowerStream Inc. has adopted the deterministic approach to planning.

The deterministic planning technique is based on an N-1 contingency criteria for planning and capital works programs. The N-1 criteria means that all loads will continue to be supplied with a major distribution network element out of service until that element is repaired or replaced, effectively ensuring zero interruptions to customers following any single outage of a major network element, such as a 230 kV supply circuit(s) or power transformer.

For overall planning objectives, at the transmission line and station transformer level, PowerStream aims to achieve a distribution system that is capable of satisfactorily withstanding any single contingency event. This will be achieved by applying a deterministic approach (N-1) to planning the distribution system. This N-1 standard provides for the planned or unplanned removal from service any 230 kV transmission line or station transformer without a sustained interruption to customer loads.

Although not adopted by PowerStream, the probabilistic planning approach relaxes the strict rules of the deterministic technique and studies are conducted to assess the amount of energy that would not be supplied if a major network element were out of service. The system design does not change with probabilistic approach, only the timing of capacity additions and distribution augmentations does.

2.4.3 Reliability Planning

Power Stream measures distribution system reliability in terms of industry and regulator accepted component indices. These indices are customer oriented and have units of "frequency of outage per year" and "outage duration in hours".

The Ontario Energy Board requires that all distributors monitor the three basic system indices of SAIDI, SAIFI and CAIDI on a monthly basis and report them annually. These three basic system indices are defined as follows:

SAIDI = Customer Hours/System Customers
(i.e. the average length of interruption per customer on the system)

SAIFI = Customers Affected/System Customers
(i.e. the average number of times an interruption occurred per customer on the system)

CAIDI = Customer Hours/Customers Affected = SAIDI/SAIFI
(i.e. the average length of interruption per customer interrupted)

The Ontario Energy Board's Guidelines are as follows:

"Utilities that have at least 3 years of data on the Service Reliability Indices should at minimum remain within the range of their historic performance. All utilities are required to monitor the indices monthly and report to the Board on an annual basis".

PowerStream's 3 Year (2004 – 2006 moving) Average is as follows:

SAIDI = 0.847
SAIFI = 1.259
CAIDI = 0.684

PowerStream's regulatory target for service reliability is to remain within the range of the past three year's historic indices performance. Significant deviations from target service reliability would trigger appropriate planning responses to restore service reliability to target levels. PowerStream's internal reliability target is set through consultation with the Reliability Performance Committee. There is no internal indices target for the 2008-2009 Budget program. Target and associated reliability improvement programs/funding are to be determined for the 2009-2010 Budget period.

2.4.4 PowerStream Planning Principles (Criteria, Practices and Guidelines)

Below is a summary of PowerStream's Distribution Planning Standards, which consist of Criteria, Practices and Guidelines.

System Voltages

- The primary supply voltage for PowerStream shall be 27.6kV. In certain areas, where 27.6 kV is not available, 44kV or 13.8kV may be utilized. Selection is governed by the Conditions of Service.

Load Forecast (Practice)

- An annual summer/winter peak demand load forecast is prepared by System Planning for each transformer station and associated feeders (usually over a 10 year window) forming the basis of all planning assessments in the current year. Distribution facilities are planned and designed to meet the expected peak demand as outlined in the official corporate forecast. See Section 2.8 for details.

Feeder Loading (Guideline)

- All 16/27.6 kV feeders shall be designed for full backup capability over peak loading conditions through the switching of load to an adjacent feeder or multiple adjacent feeders. In order to facilitate this restoration capability, three phase feeder loading will be planned to a maximum of 400 amps and 600 amps under normal and emergency operation, respectively.

- In certain industrial/commercial areas a normal operating limit greater than 400 amps is acceptable provided remotely controlled switching is available for load transfer to adjacent feeder(s) during emergency condition.

Transformer Loading (Guideline)

- Station Transformers maximum allowable loading, under contingency conditions, is the 10-day limited time rating (LTR). This loading is 1.4 and 1.6 of the transformer-cooled rating for summer and winter, respectively. Transformation capacity will be added when a station reaches 100% of its 10 day limited time rating (LTR)

Number of Feeders at Transformer Stations (Practice)

- For the purpose of determining the number of feeders emanating from a transformer station, an average loading of 15 MVA per feeder will be used; (e.g. 27.6 kV nominal voltage, transformer capacity 75/100/125 MVA, Summer 10-day LTR of 170 MVA, the number of feeders is 12 with an average load per feeder of 14.2 MVA). Additional feeders should be planned and placed into service when the average summer peak load per feeder exceeds 15 MVA.

Feeder Egress Cable & Overhead Conductor Size (Practice)

- For 27.6 kV feeders, 1000 MCM Cu, XLPE (in a concrete encased duct bank where required)_will be used for a length from the TS breaker to the cable riser switch or to a suitable point (a switch) where the feeder separates and takes an overhead route. The concentric neutral shall be single-point bonded, grounded at the station end. The riser end shall be terminated with a 3 kV arrestor, without an isolator and a 2/0 copper ground lead. A separate neutral conductor shall be used consisting of no more that two sizes smaller than the phase conductor.

- For the overhead part of the feeder main conductor, 556 MCM Al. on poles with armless construction will be used. Overhead laterals of more than 200A that could be tied to another feeder or feeder lateral will also have 556 MCM Al conductors. The neutral conductor will also be 556 MCM Al within a distance of 1.0 km from the transformer station. Beyond a distance of 1.0 km, from the transformer station, 3/0 ACSR will be used as the system's neutral.

Planning Horizon (Practice)

- Short Term Planning Horizon = 0-3 yrs
- Long Term Planning Horizon = 4+ yrs

Economic Analysis (Practice)

- Lowest life cycle cost using discounted cash flow analysis. The economic analysis should include capital and maintenance

First Contingency

- First contingency (N-1) must be covered. Sufficient backup facilities should be planned so that primary supply can be restored from an alternate source at peak demand in contingency of a failure of a "major network component".

Distribution Automation

- Distribution automation through remote switching is to be provided when cost justified ensuring that any load lost during single contingencies can be restored in a minimum amount of time. PowerStream applies the following criteria for the selection of remote switching :
  a) Distribution feeder should be segmented, via automated switches, every 8,495 customer kilometers as a minimum (based on $87,500 per installed switch)
  b) Feeder shall be segmented by RTU switches so that the loading of each segment is no more than 150A.
  c) RTU switches should be deployed to satisfy System Control operational requirements

Industry Standards

- Industry planning standards, that are an integral part of "good utility practice" and are common to all distribution utilities, are summarized in Appendix 1.

Protection Philosophy

- PowerStream is primarily an overhead distribution system. Feeder protection shall incorporate appropriate autoreclose settings to mitigate the impact of transient faults. In certain circumstances the autoreclose setting will be disabled where all faults on the circuit are expected to be permanent in nature. Trip saving protection will be enabled to allow fuses and reclosers to isolate faults where they provide the first line of protection.

Transformer Stations

- All new transformation facilities will be built as Dual Element Spot Network (DESN) Stations.

- Currently, two types of DESN stations exist within the PowerStream service territory; Bermondsey and Jones type. New stations will be Bermondsey type (75/125 MVA) stations. The smaller (50/83 MVA) Jones type stations will be considered in areas of low growth and areas of limited growth due to service boundary constraints.

Municipal Stations

- Municipal Stations will continue to be constructed, as required, in areas of 44kV primary supply. The MS secondary supply voltage shall be 27.6 kV or 13.8kV as determined by the nature and configuration of the load.

- Municipal Stations will not be constructed in areas of 27.6kV primary supply. New load will not be added to existing Municipal Stations shall unless a 27.6kV supply is not available or financially justified. Existing MS load shall be converted to 27.6 kV when cost/reliability justified.

2.5 Asset Condition Assessment

In order to achieve success, a business enterprise needs to optimally manage the risks associated with its assets. Optimal asset management strategies are based on a holistic view, covering all business assets, including physical, human, financial and information assets.

For a power distribution company, optimal management of the physical assets plays a crucial role in ensuring the company's success. Risk of failure of in-service assets can have significant consequences that include worsening of supply system reliability, asset impairment, adverse safety impacts, adverse environmental impacts and potential third party damage. Risk mitigation, on the other hand, often requires substantial investments in form of either capital expenditure or maintenance activities and impacts both the rate payers and shareholders. Best-in-class asset management strategies involve achieving the right balance between the risk of failure and the cost of risk mitigation.

The typical Asset Management process gathers engineering and other technical information from numerous sources and ties them to the annual budgeting process. The typical Asset Management process has a number of steps:

1. Data capture
2. Asset evaluations, which translate condition and criticality information into repeatable, quantitative measures.
3. Program development, which is a risk-based economic analysis to justify and prioritize spending programs. For this project, the spending programs we are most interested in are risk-management replacement and rehabilitation programs.
4. Program execution through the Budgeting process.

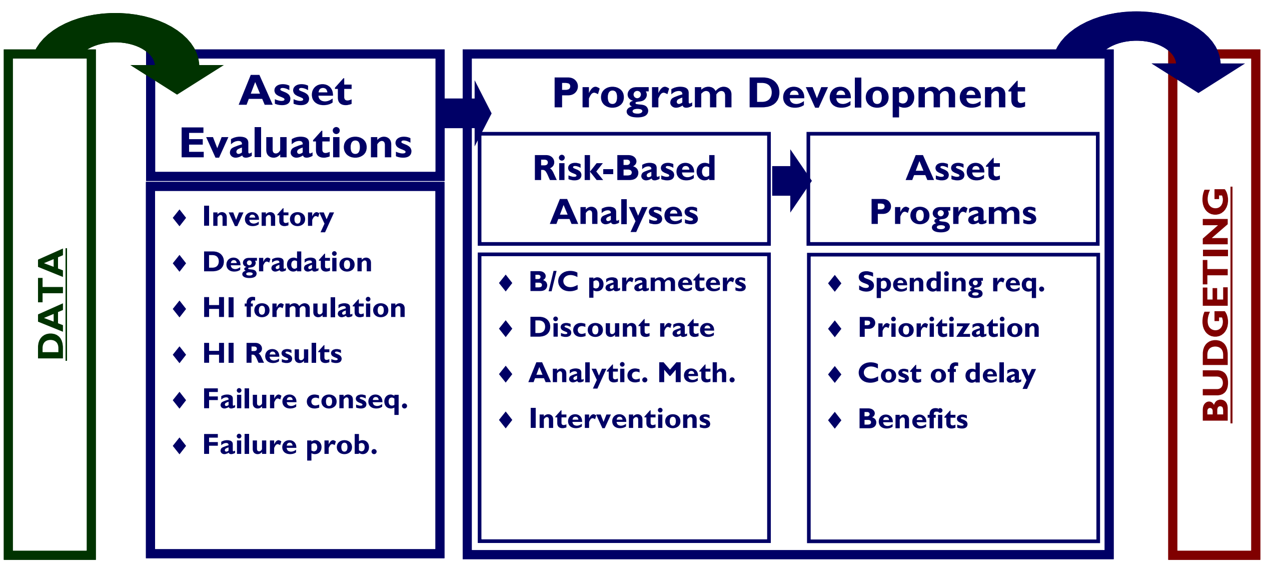
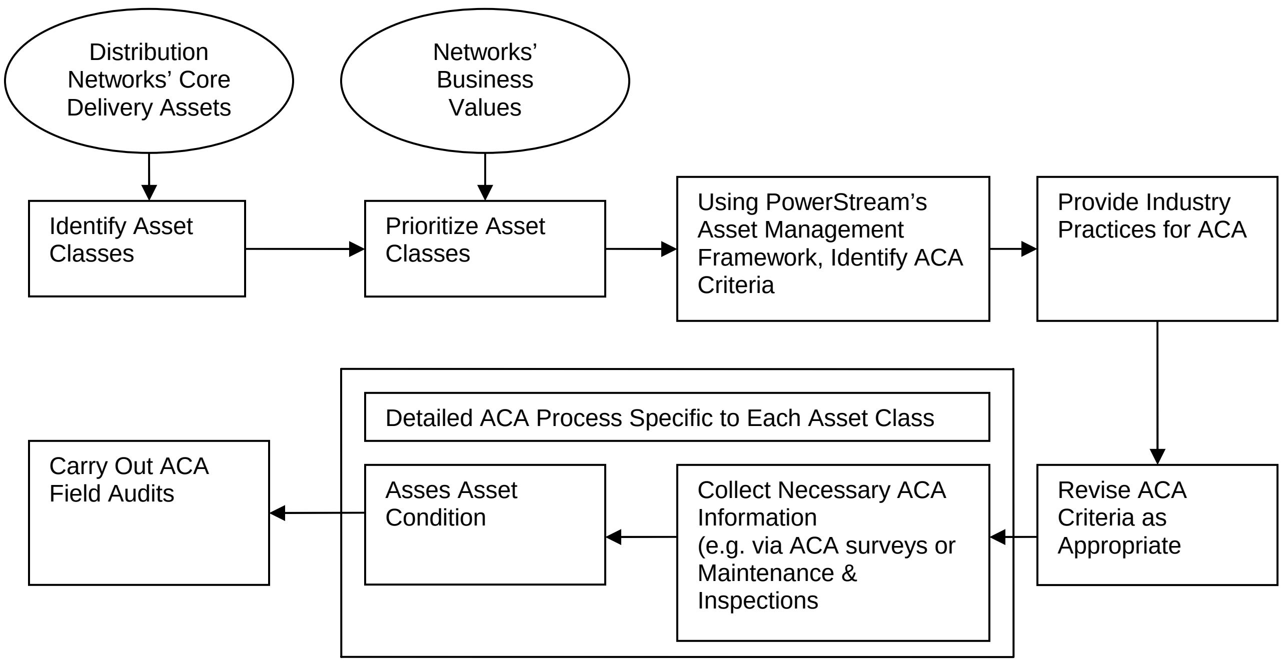


Figure 2 – Asset Management Framework

PowerStream has adopted an Asset Management Framework created by Kinectrics Inc.

As the first step in adopting optimal asset management, an objective yardstick for accurate and quantitative measurement of the health and condition of major assets, which would provide repeatable results at any moment in time needs to be developed. By taking into consideration asset health degradation processes and historic failure modes, appropriate algorithms are developed, relating the results of visual inspections, laboratory tests and other relevant demographic and operating parameters to a normalized health indicator, referred to as "Health Index". Health indices determined in this manner, allow sifting and ranking of the entire population of a specific asset class into categories ranging from "very poor" to "like new" conditions, and they will also permit quantitative determination of asset failure risk for each category, using probabilistic techniques. All consequences of failure for each asset class are identified and the overall impact of failure risk of an asset quantified using probabilistic techniques. Practical risk mitigation options for each asset category are identified and cost estimates for each mitigation option are prepared. With this model, optimal investment decisions are made by balancing the value of risk against the risk mitigation costs.

Figure 3 - PowerStream's Overall Asset Condition Assessment Process



2.6 Priority Classes for Asset Condition Assessment

It is PowerStream's intent to optimize the ACA effort by concentrating initial efforts on those assets that represent the highest priority, have a high asset value and represent a high risk to the business.

This process can be accomplished by grouping the assets into logical asset classes. These classes can be further grouped into three categories and prioritised into Priority 1 (P1); Priority 2 (P2) and Priority 3 (P3) based on the asset value to the business (Table 3).

Table 3 – Priority Categories

Priority 1 (P1)	**Priority 2 (P2)**	**Priority 3 (P3)**
Asset Class	**Asset Class**	**Asset Class**
Power Transformers/and Tap Changers (ULTC's)	Primary Underground Cables & Associated Terminations (Elbows)	Distribution Transformers (Pole/Pad Mount)
230 kV Switches	TS Oil Containment System	Fuses
Transformer Stations Switchgear c/w relays, instrumentation etc.	Substation HV Switches & Fuses	Fault Indicators
Transformer Stations Egress Cables & Terminations	Substation Sites & Structures	Concrete / steel/ composite poles
System Spare Transformers	Overhead Line Conductors	
Station Capacitors & Reactors	Wood poles	
Station Remote Terminal Units (RTU's)	RTU's - Communication Infrastructure Wireless, Fiber, Hardware, Data, Voice	
Protection/Control Relay Building	Distribution System Switchgear Oil, Gas and Air Insulated	
Substation Breakers/Reclosers & Switchgear	Switches: Scadamate, Alduti, In-Line	
Substation Transformers		

Priority 1 assets represent the highest priority assets and are of high value in terms of program expenditures or high risk to the business.

Priority 2 assets are second in priority with moderate program expenditures and moderate risk to the business.

Priority 3 are the lowest in priority with low program expenditures or low risk to the business. A number of assets in this category are considered "run to failure" assets. Assets in this category tend to have relatively consistent historical spending.

For the assets, detailed asset condition assessments are carried out that involve documenting asset description, demographics, condition criteria, comparison with industry practice and condition assessment results. Program development to prioritize spending will be part of the budgeting process. Limited program emphasis will be placed on the asset condition of P3 assets, because acquiring asset condition information on these assets is of "low" value for the following reasons:

- The assets are of low dollar value in terms of ongoing investments and it is not cost effective or practical to collect ACA information on these assets e.g. Distribution Line Fuses.
- When these assets fail, risks and consequence costs are considered relatively low and managed processes exist to quickly identify and repair or replace assets that have failed, or are about to fail ("run to failure"), e.g. pole-top transformers.
- Programs that are developed are likely to support historical replacement expenditures in the

respective asset category

2.7 Priority Asset Detail

Transformer Stations (TS) - Power Transformers

PowerStream has 10 - 75/125 MVA and 10 – 50/83 MVA Power Transformers located at 10 DESN stations. Location, description, age and condition information is noted in Table 4 below:

Table 4 – Power Transformer Health Indices

Location	Position	Manufacturer	Model	MVA Nameplate	Age	Health Index
Greenwood -Vaughan MTS #1	T1	TTI	ABB	125	17	**94**
Greenwood -Vaughan MTS #1	T2	TTI	ABB	125	17	**80**
Greenwood -Vaughan MTS #1 Expansion	T3	ABB	ABB	125	14	**93**
Greenwood -Vaughan MTS #1 Expansion	T4	ABB	MR	125	1	**89**
Torstar - Vaughan MTS #2	T1	ABB	ABB	125	14	**84**
Torstar - Vaughan MTS #2	T2	ABB	ABB	125	14	**86**
Lorna Jackson - Vaughan MTS #3	T1	ABB	MR	125	5	**86**
Lorna Jackson - Vaughan MTS #3	T2	ABB	MR	125	5	**86**
Lazenby MTS1 - Richmond Hill MTS#1	T1	Hyundai	MR	125	14	**81**
Lazenby MTS1 - Richmond Hill MTS#1	T2	Hyundai	MR	125	14	**84**
Lazenby MTS1 - Richmond Hill MTS#2	T1	Pauwels	MR	83	4	**88**
Lazenby MTS1 - Richmond Hill MTS#2	T2	Pauwels	MR	83	4	**94**
J.V. Fry - Markham MTS#1	T1	Ferranti Packard	FP	83	20	**92**
J.V. Fry - Markham MTS#1	T2	Ferranti Packard	FP	83	20	**92**
A.M. Walker - Markham MTS#2	T1	TTI	ASEA	83	18	**94**
A.M. Walker - Markham MTS#2	T2	TTI	ASEA	83	18	**87**
D.H. Cockburn - Markham MTS#3	T1	ABB	ABB	83	14	**88**
D.H. Cockburn - Markham MTS#3	T2	ABB	ABB	83	14	**86**
D.H. Cockburn - Markham MTS#3 Expansion	T3	Pauwels	MR	83	2	**94**
D.H. Cockburn - Markham MTS#3 Expansion	T4	Pauwels	MR	83	2	**94**

All power transformers have been assessed as “Very Good” or “Good” condition. No planned refurbishment or replacement needs are noted within the timeframe of this report.

As additional Priority Assets get evaluated through the Asset Condition Assessment program, they will be detailed in this section. See Table 5

2007 Transformer Events

On June 19, 2007 a lightning storm passed through the Vaughan area causing a total station outage at Vaughan TS#3. 102 MW of power was restored for the 10 feeders from adjacent supplies at Vaughan TS#1, Vaughan TS#2, Kleinberg and Woodbridge. Vaughan TS#1-T4 and Richmond Hill TS#2-T4 also tripped off load with no load loss. Relay settings for the affected station were reviewed and amended.

On November 15, 2007 a forced outage of J.V. Fry T2 occurred due to a failure of an external low voltage bushing. The transformer remained out of service for approximately 3 weeks. The failed low voltage bushing as well as the other two phase bushings were replaced. A subsequent examination and testing of the transformer indicated no internal damage to the unit and the unit was returned to service in December, 2007.

Table 5 - Asset Condition Assessment Optimal Replacement Schedule (10 year horizon)

$$ in 000,000

Item	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
75/125 Power Transformers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
50/83 Power Transformers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
230kV Disconnect Switches and structures	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
TS Switchgear & CB MS Switchgear and CB	$0	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8
TS Cap Banks and Reactors	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
TS RTU	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
Primary Underground Cable & TS Egress Cables	$0	$2	$4.5	$7.1	$7.1	$7.1	$7.1	$7.1	$7.1	$7.1
TS Building, oil containment, services	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
Wood Poles	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
Concrete Poles	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
Fibre Poles	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
Composite Poles	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
MS Power Transformers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
MS structures, switches, fuses	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
Distribution Switchgear	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
Distribution switches (manual)	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
Distribution switches (remote control)	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
Dist. RTU, comm. lines, radio equip.	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
Distribution padmount TX	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
Distribution Overhead Tx	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
Distribution Fuses, Insulators, Arresters	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD

NOTE: Based on the initial ACA program output and constrained through the budget approval process.

2.8 Load Forecast (2008-2017)

As noted in Section 2.5, PowerStream prepares an annual load forecast for the upcoming ten year period.

The load forecast is prepared by comparing trend analysis software results to weather normalized end use forecasts. The weather normalization is based on normal, hot and extreme conditions, while the end use forecast is based on normal, low and high growth. All forecasts include CDM and price elasticity impacts.

The load forecast for the period of 2008 – 2017 is noted below, and is summarized in Table 11.

Three different forecast results are utilized depending on the audience and application.

1.Submission to Hydro One, the IESO, the OPA and the OEB

The coincident peak demand forecast of Base growth under the “1 in 2” (“normal”) and “1 in 10” (hot) weather scenarios with 5% peak reduction through CDM by 2007, and with price elasticity impact is provided to external agencies for capacity planning purposes.

2. Internal Financial/Revenue forecast purposes

The coincident peak demand forecast of Base growth under the “1 in 2” (“normal”) weather scenarios with 5% peak reduction through CDM by 2007, and with price elasticity impact is provided for internal financial/revenue forecast purposes.

3. System Capacity Adequacy Assessment

Coincident peak demand forecasts of Base growth under the “1 in 10” weather scenario without CDM and without price impact are provided for system capacity adequacy assessment.

Table 11: PowerStream Coincident Peak Demand Forecast -Base growth (MW)

Purpose	Item	Weather	2006*	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
OPA/OEB	Peak (MW)	1 in 2	1,481	1,375	1,420	1,453	1,486	1,538	1,592	1,647	1,704	1,763	1,823
		1 in 10		1,491	1,540	1,576	1,612	1,668	1,727	1,786	1,848	1,911	1,977
Financial/ Revenue	Peak (MW)	1 in 2	1,481	1,375	1,420	1,453	1,486	1,538	1,592	1,647	1,704	1,763	1,823
	Energy (GWh)	1 in 2	6,729	6,623	6,842	6,998	7,160	7,411	7,669	7,935	8,210	8,492	8,783
Capacity Assessmant	Peak (MW)	1 in 10	1,481	1,533	1,594	1,642	1,691	1,742	1,794	1,848	1,904	1,961	2,020
	Peak (MVA)	1 in 10	1,646	1,703	1,772	1,825	1,879	1,936	1,994	2,054	2,115	2,179	2,244

*Actual

The load forecast indicates that bulk transformation capacity increases, based on standard 75/125 MVA DESN station transformation capacity, are required in 2010, 2013 and 2016.

2.9 Inclusions from 2007

2.9.1 Load Based Reliability Indices

In 2007, PowerStream investigated the applicability of Load Based Reliability Indices. These indices use the load interrupted rather than the number of customers interrupted to calculate frequency and duration of interruptions.

The study investigated 56 key accounts and provided these results (Table 7A from the report):

Table 7A: Reliability Indices Comparison-2007

Key Customers				PowerStream	
SAIFI	1.36	ASIFI	1.28	SAIFI	1.543
SAIDI	115.32	ASIDI	109.47	SAIDI	130.80
CAIDI	84.97	ASIRI	85.57	CAIDI	84.30

Table 7A indicates that there is no significant difference between customer based indices and load based indices.

Excluding Major Event Days in 2007 from the calculations, reliability indices were recalculated and results are shown in Table 7B (from the report).

Table 7B: Reliability Indices Comparison-2007

Key Customers				PowerStream	
SAIFI	1.13	ASIFI	1.04	SAIFI	1.179
SAIDI	41.02	ASIDI	34.22	SAIDI	55.69
CAIDI	36.46	ASIRI	32.79	CAIDI	47.24

Table 7B indicates that:
- ASIFI is approximately the same as SAIFI.
- ASIDI is 17% lower than SAIDI.
- ASIRI is 10% lower than CAIDI.

In other words, the 56 key customers experience the same number of interruptions in terms of customers and kVA connected, but the outage duration was much shorter in terms of kVA connected.

As a result of the study, the **recommendation** with respect to load based reliability indices is:

Step1: As a pilot project, indices for the 56 key customers are to be calculated for 2007 and compared with the results of 2006. The results of 2006 and 2007 are to be presented to PowerStream's reliability committee in early 2008. A decision should be made by the committee if load based indices should be:

- implemented on the key customers for 2008 and reported monthly with the other normally reported indices
- implemented in 2008 on a larger scale with more customers and reported monthly with the other normally reported indices.

- not implemented as standard reporting indices.

Step 2: If results from step 2 are proven to be valuable, load based reliability indices shall be applied to all customers in PowerStream; in the same way as customer based indices are calculated and monitored. Targets would then need to be developed and monitored.

2.9.2 CAIDI Calculations

In 2007, PowerStream investigated the applicability of applying a methodology to calculate the improvement of CAIDI as a result of capital works that improve restoration times.

The report dealt exclusively with the system configuration factor as it pertains to system planning related budget project recommendations. The goal was to develop a methodology to be applied to projects in order to demonstrate an improvement, however small, in CAIDI

For projects where restoration times can be improved, a calculation, performed on a standard form, will be performed and will include the reduction in outage restoration time for a feeder(s), the number of customers for both before and after construction which are used in calculating the new indices.

The calculation will be based on individual feeder indices, then applied to the system indices.

There are many locations that a fault could be applied to the proposed configurations. For the purposes of establishing a reliability index comparison, the perceived worst outage (ie longest restoration time) will be used. The calculation will be based on the existing configuration at the time the calculation is performed.

These will be applied for future recommended projects as a ranking tool for best CIADI improvements.

2.10 2008 Initiatives

2.10.1 Safety Calculator

In late 2007, The Electrical Safety Authority (ESA) created a "Ranking Tool for Distribution Related Equipment', a system that will assist utilities in determining priorities to ensure public and worker safety in Ontario.

Engineering Planning will be applying this risk assessment tool to future recommended projects to facilitate the identification of electrical safety risks and to prioritize projects with respect to public safety concerns.

2.10.2 Worst Performing Feeders

Proposed in the 2008 work plan for System Planning is a review of the historical worst performing feeders, performing a root cause analysis on outages and preparing a report with appropriate and relevant improvement recommendations for the EMT. This will become an annual exercise.

2.11 Contingency Plans

Contingency Plans are required to deal with any asset related event that affects the proper functioning of the distribution system. Contingency planning with respect to this document will deal with potential high impact low probability (HILP) events that can have major repercussions on the distribution system and our customers. This will mostly apply to Priority 1 assets. All other events, that are generally regular occurrences, low impact, low scope and have established processes to deal with them, are not part of this document. The HILP events considered here are shown in the Table 6 below:

Table 6 – Contingency Plans

Asset Class	Contingency Event	Contingency Plan
TS Power Transformers	Transformer failure requiring off-site servicing	1. Spare Transformer 2. Storage location for spare 3. Individual plans to move spare to affected TS 4. Individual connection plans for each TS configuration
TS Switchgear Cell(s)	Cell or multi-cell failure	1. Spares – Critical parts list 2. Contact plan for manufacturer repair support 3. Spare cell 4. Feeder emergency loading capability
230kV switches	Switch failure – non-repairable	1. Spare switch(s)/parts 2. Storage location for spare(s) 3. Individual mounting plan(s) for each TS structure
TS Feeder cables	Failure of one or more underground cables	1. Spare cable reel
TS Capacitor banks	Failure of significant portion of capacitor bank	1. Spare Capacitor cans 2. Contact plan for manufacturer repair support
TS Reactor failure	Failure of reactor	1. Spare reactor
Station RTU	Failure of RTU leading to loss of station control	1. Standby staff to man station 2. Contact plan for manufacturer repair support
Station Protective Devices	Device failure leading to full/partial loss of station	1. Spare – Critical Parts list
Poles	Loss of high number of pole structures through high impact event(severe weather, etc.)	1. Stock poles 2. Supplier stock 3. Neighbouring LDC stock

In all cases if available contingency measures prove insufficient, rotating load shedding may be required to ensure equipment is not loaded beyond approved tolerances.

2.12 Review of Previous System Planning Report

The performance of the previous planning report needs to be annually reviewed to:

1. determine actual progress versus the plan;
2. evaluate and compare actual performance of the plan against targeted performance objectives;
3. identify any gaps in the plan and resultant performance improvement initiatives.

The 2007 Distribution System Planning Report is the second comprehensive summary of plans and planning processes presented in this format.

Plan Progress

The 2007 Budget identified a number system augmentation projects. Status of those projects is shown in Tables 7 and 8 below:

Table 7 - System Planning Projects

Recommended Projects	Details	Received Budget Approval	Project Completed
Asset Condition Assessment	Phase 2	Yes	Yes
York Region Land Development Map	tools	No	No
Spare 75/125 MVA transformer		Yes	IP
Power Factor Meters and Recorders	tools	No	No
Markham TS4 land purchase	acquisition	Yes	No
Environmental Assessment Consulting	consulting	Yes	IP
IESO Connection Assessment		Yes	n/a
HONI feeders	purchase	No	n/a
North Lake road	Conversion to 3 ph	No	n/a
Denison, Warden to Esna Park	feeder extensions	No	n/a
SCADAMATES	20 locations	No	n/a

Table 8 - Station Design & Construction Projects

Recommended Projects	Details	Received Budget Approval	Project Completed
Fibre Communications Expansion	SONET Ring extension	Yes	Yes
Corporate LAN communications	east/west tie	Yes	Yes
Greenwood TS Drainage Improvement		Yes	Yes
Torstar TS Cap Banks		No	No
Lazenby TS video surveillance		No	No
Lazenby TS control ducts	Between TS1 and TS2	Yes	IP
Markham TS2 drainage study		Yes	90%s
Markham TS1 cap bank replacement		Yes	Yes
230kV Back-up line protection settings		Yes	75%
12M3 and 22M5 reclosers		Yes	90%
Markham TS4	New station	Yes	IP
Aurora MS6	second tx	Yes	IP

IP = In progress

Performance Targets

Reliability comparison – The projected SAIDI,SAIFI, CAIDI indices for 2006 and the 3 year SAIDI, SAIFI, CAIDI averages for 2004 – 2006 are:

	2007*	2004 – 2006 Average
SAIDI	2.090	0.847
SAIFI	1.419	1.259
CAIDI	1.473	0.684

* end of October

Plan Gaps and Performance Improvement Initiatives

Noted gaps in the previous plan -

- At the transformer station level , the lack of spares for the 50/83 MVA transformers continues to elevate N-1 contingency risks
- Distribution automation has not kept pace with system growth.
- Feeder augmentation plans have been deferred to future budgets

Performance objectives not achieved – System reliability performance is outside range of previous performance

Deteriorating performance as compared to previous plan - there has been a significant increase in outage frequency and duration at the customer and system level that may indicate a need to address power restoration issues through enhanced operational processes, contingency planning and distribution automation. It is noted that severe weather events early in 2007 were the prime contributors to the decline of service reliability.

3.0 SUMMARY & RECOMMENDATIONS

It is recommended that capital funding, in the areas noted below, be included in the 2008 and 2009 Budget Programs. Specific program details are in Appendices 3 and 4.

Table 9 – Summary of Total Recommended 2008-2009 Capital Funds
(all $ in 000)

A) Planning

Category	2008 BUDGET $000	2009 BUDGET $000	2010 BUDGET $000	2011 BUDGET $000	2012 BUDGET $000
Special Projects	4,891	8,200	9,900	8,925	12,900
Reliability Projects	3,201	5,452	5,278	3,928	4,780
Capacity Projects	6,570	32,506	3,900	7,323	22,562
TOTAL DOLLARS	$14,662	$46,158	$19,078	$20,176	$40,242

B) Station Design

Category	2008 BUDGET $000	2009 BUDGET $000	2010 BUDGET $000	2011 BUDGET $000	2012 BUDGET $000
Special Projects	$1,932	$415	$295	$1,026	$143
Reliability Projects	$2,045	$277	$418	$2,912	$409
Capacity Projects	$7,720	$11,285	$1398	$4,519	$17,820
Unplanned Projects	$0	$0	$0	$0	$0
TOTAL DOLLARS	**$11,697**	**$11,977**	**$2,111**	**$8,097**	**$18,372**
Category	**2008 BUDGET $000**	**2009 BUDGET $000**	**2010 BUDGET $000**	**2011 BUDGET $000**	**2012 BUDGET $000**
Special Projects	$1,932	$415	$295	$1,026	$143
Reliability Projects	$2,045	$277	$418	$2,912	$409
Capacity Projects	$7,720	$11,285	$1398	$4,519	$17,820
Unplanned Projects	$0	$0	$0	$0	$0

TOTAL DOLLARS	**$11,697**	**$11,977**	**$2,111**	**$8,097**	**$18,372**

Category	**2008** BUDGET **$000**	**2009** BUDGET **$000**	**2010** BUDGET **$000**	**2011** BUDGET **$000**	**2012** BUDGET **$000**
Special Projects	$1,932	$415	$295	$1,026	$143
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TOTAL DOLLARS	**$11,697**	**$11,977**	**$2,111**	**$8,097**	**$18,372**

Appendix 1

Distribution System Planning Standards (Criteria, Practices & Guidelines)

Following is a summary of general Distribution System Planning Standards, common to all LDCs,, which consist of Criteria, Practices and Guidelines. The are an integral part of "good utility practice" in distribution planning.

Voltage Level (Criteria)
Service voltages shall comply with the standards of the Canadian Standards Association, CSA Standard CAN3-C235-83.

CSA Standard CAN3-C235-83 "Preferred Voltage Levels for AC System, 0 to 50,000 volts"

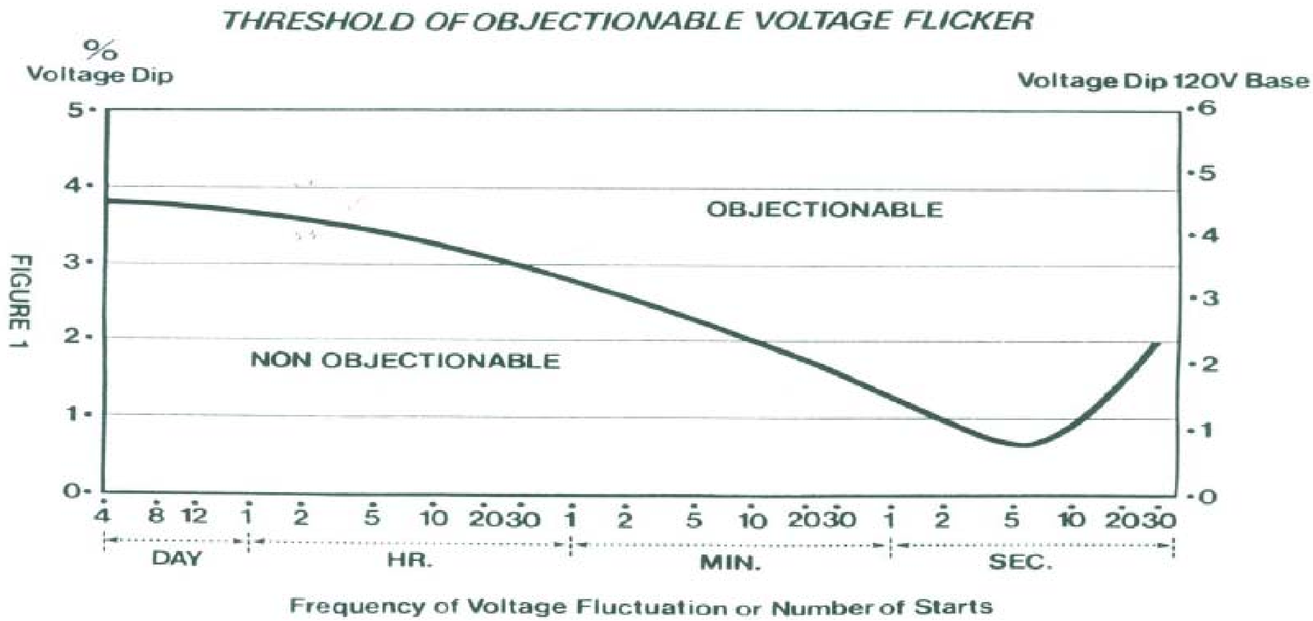
Recommended Voltage Variation Limits for Circuits up to 1000 volts, at Service Entrance

Nominal System Voltage	Voltage Variation Limits for Circuits up to 1000 v, at Service Entrances			
	Extreme Operating Conditions			
		Normal Operating Conditions		
Single-Phase				
120/240	106/212	110/220	125/250	127/254
240	212	220	250	254
480	424	440	500	508
600	530	550	625	635
Three-Phase 4 - Conductor				
120/208 Y	110/190	112/194	125/216	127/220
240/416 Y	220/380	224/388	250/432	254/440
277/480 Y	245/424	254/440	288/500	293/508
347/600 Y	306/530	318/550	360/625	367/635
Three-Phase 3 - Conductor				
240	212	220	250	254
480	424	440	500	508
600	530	550	625	635

Voltage Unbalance (Guideline)
Voltage unbalance is defined as the maximum phase voltage deviation from the average phase voltage, as a percentage of the average phase voltage. All single-phase load additions shall be connected to the main feeder in a manner to balance the overall three-phase load with respect to voltage. The goal is to maintain the individual phase voltages of a main three-phase feeder to within 3% of each other.

Current Unbalance (Guideline)
Current unbalance is defined as the neutral current or approximately the maximum phase current deviation from the average phase current, as a percentage of the average phase current. Feeders with a phase current deviation in excess of 20% from average will be considered for rebalancing.

Voltage Flicker (Guideline)
Flicker can be defined as a perceptible change in lamp output produced by a sudden change in supply voltage.



Neutral Potential (Guideline)
Neutral Potential of up to 10 Volts is acceptable.

Power Factor (Guideline)
Power Factor on feeders as measured at the station bus shall be kept at a minimum of 95% at peak load and a maximum of 100% at light load periods.

Feeder Line Loss Reduction (Practice)
Losses on three phase feeders should be kept to a minimum through the use of appropriately sized conductor, optimal feeder loading and load sharing, phase balancing, and in some cases, applications of shunt capacitors. At the present time the industry standard for a typical Urban utility is in the range of 2.5 -3.5%.

Harmonics (Guideline)
Harmonics are frequencies other than the standard 60-cycle waveform, which can contribute to the malfunction or inefficient operation of electrical devices. Harmonics are usually introduced onto the distribution feeders via non-linear equipment and can be propagated through the system. All customer owned equipment that is connected to the distribution system would be required to comply with the applicable standard such as the IEEE 519 and IEEE STD. #519-1992.

Reliability (Guideline)
The Regulator's Guidelines are as follows:
"Utilities that have at least 3 years of data on the Service Reliability Indices should at minimum remain within the range of their historic performance. All utilities are required to monitor the indices

monthly and report to the Board on an annual basis".

Maximum Fault Duration and Ground Potential Rise (Criteria)
Maximum fault duration on lines involving joint use with communication facilities is 3 sec.
Maximum neutral Ground Potential Rise (GPR) is 3000 Volts (CSA C22.3, #5)

Thermal Loading
During normal operating conditions (all elements in service) the load on all network elements should not exceed established normal ratings (continuous loadability). In contingency condition (loss of a major network element), the load on the remaining elements should not exceed established emergency/limited time ratings. Emergency ratings indicate loadability of equipment for short periods of time and accepting a loss of life of the equipment.

Overhead Conductors (Guideline)
The maximum conductor ampacity based on Perpendicular Wind of 0.61 m/s, Conductor Temperature 90° C, and Ambient Temp. 30° C is as follows:

Conductor	**Ampacity**
556 Al	**777 A.**
336 Al	**564 A.**
4/0 ACSR	**422 A.**
3/0 ACSR	**365 A.**
1/0 ACSR	**273 A.**

Underground Feeder Station Egress Cables (Guideline)
All new underground station egress cables can be Single-Point or Two-Point bonded. When Single-Point bonded is used, a separate neutral is required. The size of the neutral cable shall be no smaller that two sizes below the phase conductor.

The following table shows typical cable ampacities for both grounding options. For site-specific normal and emergency rating, site-specific calculations should be carried out.

The following ampacities are based on 90° C for conductor, 25° C for ambient (soil), thermal resistivity of soil is 90°C cm/watt, and burial depth is approximately 3 m.

Cable Size	Circuits in Duct bank	Two-Point bonded	Single-Point bonded
500 MCM XLPE, Cu*	1	395 A	542 A
750 MCM XLPE, Cu*	1	439 A	678 A
1000 MCM XLPE, Al*	1	-	617 A
750 MCM XLPE, Cu*	2	373 A	576 A
1000 MCM XLPE, Al*	2	-	524 A
1000 MCM XLPE, Cu*	2	-	630 A

A general guideline for determining cable ampacity for multiple feeders in a duct bank is to find the rating from the cable manufacturer for the particular cable in duct and then apply a de-rating factor of 0.7.

APPENDIX 2

Asset Condition Assessment Framework

The following sections describe the asset management framework in detail. The framework basically comprises of the following three elements:

- Management process for a specific asset class
- Overall asset management planning process
- Process for development of a budget for unscheduled maintenance.

<u>Management Process for a Specific Asset Class</u>

Figure 1 shows the flowchart recommended to be employed to support decisions for a specific asset class. This process employs inputs related to asset condition, criticality, and functionality to perform risk-based economic analysis. The results of this analysis will be evaluated against external drivers, such as corporate goals, regulatory requirements, and health and safety goals, to produce an intermediate program. This intermediate program will be initially developed, considering only the single asset group in question. The program will then be considered for all asset group in optimizing the overall asset management plan.

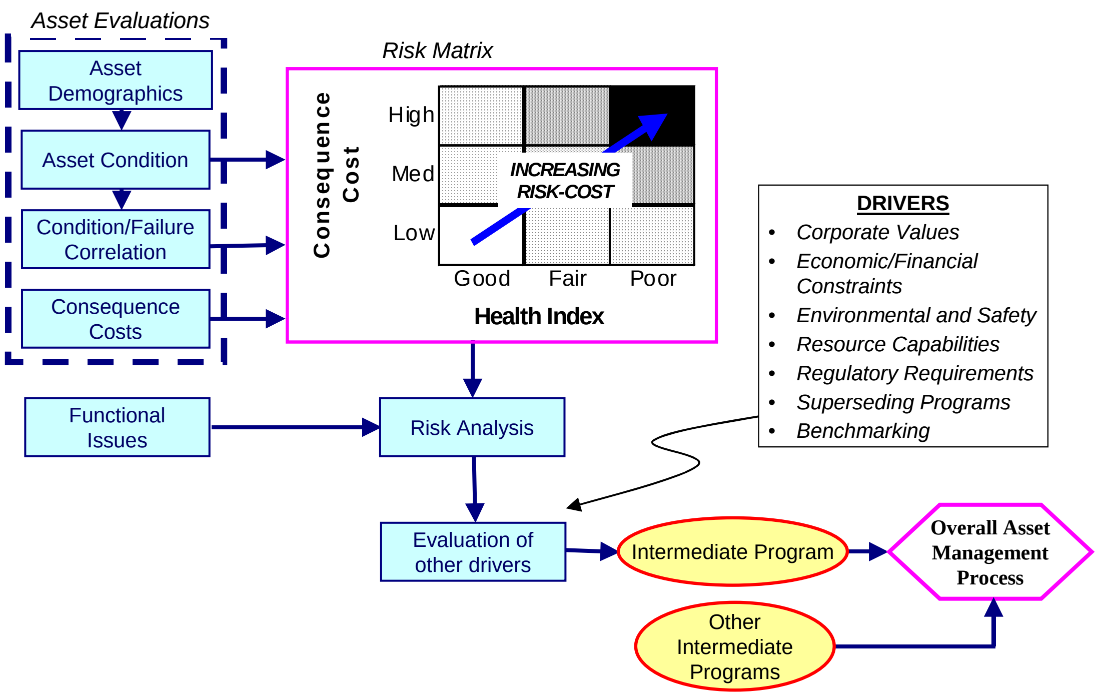


Figure 1 - Management Process for a Specific Asset Group

<u>Asset Evaluation Inputs</u>

The first group of inputs is grouped under Asset Evaluation inputs, as shown inside the dashed box. These inputs define the status of health and condition of existing asset categories, providing an indication of probability of failure risk as well as the consequences of failure. In order for the model to provide accurate results with high confidence levels, it is important that the required information on assets be available.

Asset Demographics includes historic information on assets to permit them to be divided into appropriate categories, so that assets within each category can be independently assessed. Common asset demographic input parameters include asset age, asset quantity, asset type, installation location, and other distinguishing parameters of use.
Asset Condition input parameters include results of visual inspections, in-situ testing, laboratory testing or other diagnostics that might provide information on asset health and condition. By assigning appropriate weights to various condition indicators, a normalized health index, indicating the asset health on a scale of "0 to 100" is intended to be developed.

Condition/Failure Correlation is based on historic failure modes and trends and translates the asset demographic and asset condition information into failure probability. Equipment procurement specifications, historic loading trends, environmental conditions and past preventative maintenance practices, all play a role in determining asset failure probability and will be taken into account.

Consequence Cost is the sum of all anticipated financial consequences of asset failure based on probabilistic model, which is a function of the criticality of the asset within the supply system network. Consequence costs include asset replacement cost, customer loss due to power interruption, other customer damage, environmental and safety effects, and all other impacts. All tangible consequences of asset failure will be expressed quantitatively; by taking into account asset functions, (e.g., dead-end poles versus tangent poles; heavily-loaded transformers versus lightly-loaded ones).

In addition to the asset evaluation inputs described above, there are external drivers that impact the investment decisions. Table 1 lists the asset evaluation inputs along with the external program drivers that can be employed during in the asset specific management process. This list should not be considered exhaustive; it is intended to give an idea of the types of inputs expected to be included in the final process.

Table 1 - Asset Management Process Inputs

Process Inputs	Input Types	
	Asset Evaluation	Program Drivers
1. Condition	A	
2. Performance (including outliers)	A	
3. Benchmarking	A	P
4. Criticality	A	
5. Consequence cost	A	
6. Corporate values		P
7. Regulatory requirements (ie, OEB)		P
8. Safety and environmental	A	P
9. Tertiary regulation (ie, legislative)	A	P
10. Cost and benefit of action		P
11. Probabilities	A	
12. Capacity and ratings	A	
13. Resource cababilities		P
14. Target IRR, NPV, etc.		P
15. Cash flow		P
16. Duration in specific environment	A	
17. Industry standards	A	
18. Demographics	A	
19. Politics and history		P
20. Stakeholders and customers		P
21. Industry peer (ie, transmission)		P
22. External drivers (ie, development)		P
23. Obsolescence or new technology	A	
24. Options	A	
25. Demand projections	A	
26. Depreciation		P

Risk Matrix

The risk matrix is used to prioritize assets based on valuation of the risk, which is defined as the product of failure probability and consequence cost. The entire population within an asset group is distributed throughout the matrix, based on the asset failure probability and the consequence risk cost for each member. Those assets further right and up in the matrix carry more risk, and are therefore higher priority, than those lower and left.

Functional Inputs

Functional inputs reflect operational factors affecting asset’s ability to carry out its intended functions and include capacity, voltage level, short-circuit level, or other characteristics of the equipment that may affect the plan for the asset for reasons other than their condition or risk. These inputs relate the capability of the asset to the operational requirements, for example heavy loading on a transformer, that will influence or drive a requirement to replace the asset.

Risk-Based Economic Analysis

The economic analysis combines the asset's risk profile and functional issues and compares them with risk mitigation investment requirements to develop an economically sound overall plan for maintaining or replacing the asset.

Assessment of Other External Drivers

All tangible costs and benefits will be considered in the economic and risk analysis. However, some external drivers may be difficult to quantify or may simply be significantly more important and may override other considerations. These will be considered separately as a series of "gates" through which the asset plan must pass. As indicated in Figure 2, these external drivers include:

- Corporate values
- Economic and financial constraints
- Environment and safety
- Resource capabilities
- Regulatory requirements
- Superseding programs
- Benchmarks

One benefit of considering these drivers after the economic analysis is that it clearly demonstrates the cost of the drivers based on the changes in the asset program.

Intermediate Program

The final output of this process is the Intermediate Program. This is an optimized plan for the single asset group or program considered, without considering its effects or interactions with any other assets/programs. The intermediate program will have the following characteristics:

- Internal prioritization, directs resources to the highest-risk assets.
- Cost/benefit streams, including risk-cost
- Makes the business case for spending on the specific asset group/program
- Provides justification for the investment to PowerStream shareholders and regulators

Overall Asset Management Planning Process

The flow chart in Figure 2 below shows the process for prioritizing and optimizing among the intermediate asset programs to develop a final asset management plan.

The key parameters of this process are described in the following.

Input, Intermediate Programs

The primary inputs to the process are the intermediate programs developed for each asset groups individually, as described previously. This input includes not only the programs themselves, but also the economic, risk, and other information supporting those programs, which is necessary to make good decisions about trade-offs among the programs.

External Drivers

The same drivers considered in developing the intermediate programs are again considered with regard to development of the overall program. This is to ensure that these overriding requirements are taken into consideration while adopting the overall program.

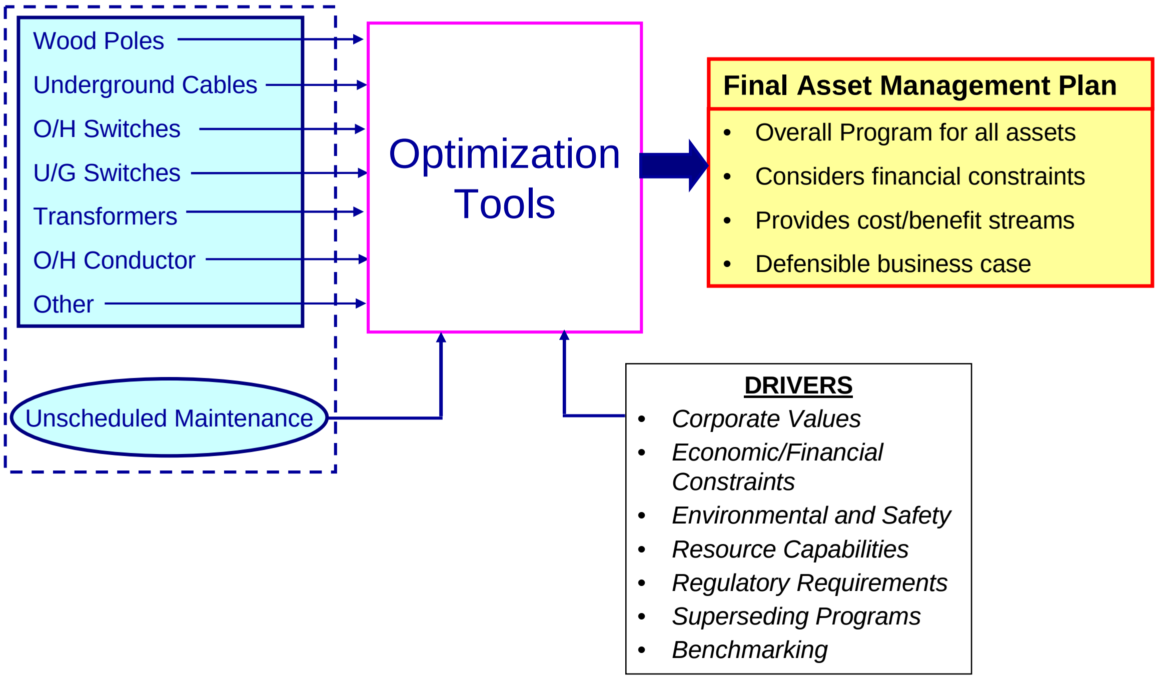


Figure 2 – Overall Asset Management Process

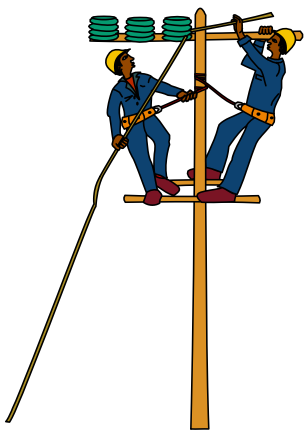
Optimization Process

The optimization process influences and ranks investment plans for all assets, by taking into consideration risk, functionality, corporate goals, regulatory requirements, and other drivers, to maximize the benefit to PowerStream from its investments.

Final Asset Management Plan

The final plan will provide a defensible business case for the spending projects and programs identified. It will also provide a basis for adjusting spending as unexpected events arise.

Five Year Capital Work Plan
Engineering Planning
System Planning Division
2008 - 2012



Prepared by: *Irv Klajman, P.Eng.*
Manager, System Planning

Reviewed by: *Ted Wojcinski, P.Eng.*
Director, Engineering Planning

5 Year Capital Work Plan, Engineering Planning 2008-2012

TABLE OF CONTENTS

EXECUTIVE SUMMARY

Selected projects are recommended by Engineering Planning for investigation or construction for the five-year period between 2008 and 2012.

The projects have been categorized as:

- Special Projects
- Reliability Projects
- Capacity Projects

The forecasts for the dollar requirements on a yearly basis are shown in Table 1.

TABLE 1: SUMMARY OF TOTAL RECOMMENDED CAPITAL DOLLARS

Category	2008 BUDGET $000	2009 BUDGET $000	2010 BUDGET $000	2011 BUDGET $000	2012 BUDGET $000
Special Projects	4,891	8,200	9,900	8,925	12,900
Reliability Projects	3,201	5,452	5,278	3,928	4,780
Capacity Projects	6,570	32,506	3,900	7,323	22,562
TOTAL DOLLARS	14,662	46,158	19,078	20,176	40,242

The numbers presented have been estimated by Design, and filtered through the Design Departments capital budget restrictions. Only the Markham TS#4 feeder integration numbers are reported here differently than in the budget system.

1.0 INTRODUCTION

1.1 Background

Selected projects are recommended by Engineering Planning for investigation or construction for the five-year period between 2008 and 2012.

The projects have been categorized as:

- Special Projects
- Reliability Projects
- Capacity Projects

Generally, PowerStream's capital work originates from construction driven by the City of Vaughan, Towns of Markham, Richmond Hill and Aurora, the Region of York, Ministry of Transportation, development of new subdivisions which require services or facilities that are not presently in place and customers installing new services or customers upgrading their electrical service capacities.

Work recommended in this document support projects that are not, in general, driven by direct legal need, governmental or regulatory bodies, and for those that have not been dictated as a requirement - they have been previously considered “discretionary” projects. These projects are aimed at improvements to system reliability and for providing additional capacity.

It should be stated that monitoring of the system’s performance is an annual undertaking and involves discussions with Operations and the recently formed Reliability Committee. Projections of specific projects for a five-year window is not an accurate exercise. Where stated, placeholders for anticipated projects have been recommended.

1.2 Purpose

This report provides the background support and justifications for projects, specifically;

a) detailing projects Engineering Planning has identified to complete the required work requested based on system analysis;
b) providing budgetary estimates of the recommended projects;
c) providing an overview of the scope of each of the projects;
d) providing a summary of the total estimated recommended costs by category;
e) provides the identification of projects that Design will require to create project estimates.

2.0 PROJECTS

2.1 SPECIAL PROJECTS

Each year, there are a number of issues that arise resulting in creating initiatives to provide solutions. These are listed below.

2.1.1 System Studies

Project SP1: Asset Condition Assessment (ACA) ***IK101***

This work would be the continuation of the work from both 2006 and 2007. The estimated expenditure in 2008 and beyond is noted below.

TABLE 2A: ACA - CONSULTANT FEES

ITEM	*2008*	*2009-2012*
Distribution Transformers	$30,000	
Distribution Switchgear	$35,000	
230kV Switches Substation HC Switches & Fuses	$33,000	
Conductors, Wood Poles, Concrete Poles, Insulators	$48,000	
Station Capacitors & Reactors	$18,000	
TOTAL	***$164,000***	***$0***

As a result of the recommendations from the reports, Table 2B lists potential capital expenditures required to maintain the assets in an acceptable manner. These have been estimated based on preliminary findings and yearly dollar smoothing. NOTE: *TBD = to be determined*

TABLE 2B: ACA - POTENTIAL CAPITAL EXPENDITURES

Item	2008	2009	2010	2011	2012
75/125 Power Transformers	$0	$0	$0	$0	$0
50/83 Power Transformers	$0	$0	$0	$0	$0
230kV Disconnect Switches and structures	TBD	TBD	TBD	TBD	TBD
TS Switchgear & CB & MS Switchgear and CB	$0.8	$0.8	$0.8	$0.8	$0.8
TS Cap Banks and Reactors	TBD	TBD	TBD	TBD	TBD
TS RTU	TBD	TBD	TBD	TBD	TBD
Primary Cables & TS Egress Cables	$0	$2.0	$4.5	$7.1	$7.1
TS Building, oil containment, services	TBD	TBD	TBD	TBD	TBD
Wood Poles	TBD	TBD	TBD	TBD	TBD
Concrete Poles	TBD	TBD	TBD	TBD	TBD
Fibre Poles	TBD	TBD	TBD	TBD	TBD
Composite Poles	TBD	TBD	TBD	TBD	TBD
MS Power Transformers	TBD	TBD	TBD	TBD	TBD
MS structures, switches, fuses	TBD	TBD	TBD	TBD	TBD
Distribution Switchgear	TBD	TBD	TBD	TBD	TBD
Distribution switches (manual)	TBD	TBD	TBD	TBD	TBD
Distribution switches (remote control)	TBD	TBD	TBD	TBD	TBD
Dist. RTU, comm. lines, radio equip.	TBD	TBD	TBD	TBD	TBD
Distribution padmount TX	TBD	TBD	TBD	TBD	TBD
Distribution Overhead Tx	TBD	TBD	TBD	TBD	TBD
Distribution Fuses, Insulators, Arresters	TBD	TBD	TBD	TBD	TBD

2.1.2 System Planning Philosophy

Project SP2: 75/125 MVA Spare Power Transformer (2008) ***IK132***

The approved Planning Philosophy adopted, in principle, the acquisition of a system spare(s) for the 20 power transformers in the PowerStream Inc. fleet.

The business case for 125 MVA unit was finalized. Spending will follow the progress payment schedule as defined by the station design group. The 230 kV 50/125MVA transformer was ordered in May 2007 along with the two TS#4 transformers. The approximate value of the unit is $3,000,000.

Payment	ARO	Amount	Budget Year	
20% successfully tested	5 months	$ 600,000	2008	
35% delivery to site	6 months	$1,050,000	2008	
25% completion of installation	9 months	$ 750,000	2008	ik132
10% hold back < 60 days	10 months	$ 300,000	2008	

Project SP3: 50/83 MVA Spare Power Transformer (2010) ***IK150***

The approved Planning Philosophy adopted, in principle, the acquisition of a system spare(s) for the 20 power transformers in the PowerStream Inc. fleet.

The 125MVA has already been approved and ordered. It was recommended that the smaller unit and an order be placed, as approval was received in
October 2007

The approximate value of the unit is $2,500,000. 2008 is the anticipated order date with delivery in 2009.

Payment	ARO	Amount	Budget Year
10% on design drawing approval	1 month	$ 250,000	2008
20% successfully tested	5 months	$ 500,000	2008
35% delivery to site	6 months	$ 875,000	2008
25% completion of installation	9 months	$ 625,000	2009
10% hold back < 60 days	10 months	$ 250,000	2009

2.1.5 Transformer Stations

Project SP4: TS#4 Vaughan Land (2010) ***IK151***

After the sites have been short listed, potential options on the lands been acquired, and after the requisite approvals have been obtained, the purchase of land will be required for a station in Vaughan that will be needed between 2012 and 2015. Alternatively, land can be purchased on speculation to assist in the probability that will be available after approvals are received.

Budget estimate of $1,000,000 is estimated for a site in Vaughan.

Project SP5: TS#5 Markham Land (2012) ***IK152***

Current load forecasts estimate a need for another DESN in Markham as early as i2015. It would be prudent to secure land options or land in advance of that date.

Budget estimate of $4,000,000 is estimated for Markham or northern Richmond Hill in 2012.

Project SP6: IESO Connection Assessment (2011) ***IK153***

A study will be required for Vaughan TS#4. Assume $25,000 in 2011.

2.1.6 Additional Supplies

Project SP7: Purchase of Hydro One Feeders (2009) ***IK131***

There are several Hydro One owned 28kV feeders that emanate from outside PowerStream Inc.'s service territory. Hydro One is permitting the sale of these assets. Part 1 of the review of these assets was performed in 2006, and a recommendation has been made to acquire some of these feeders. Discussions with neighbouring utilities and Hydro for determining cost will occur in 2008, with the fund and asset transfers in 2009.

At present, it is expected that there will be only the purchase of the Woodbridge feeder based on a cost benefit threshold of $200,000. Consideration for the conductors for Armitage M14 on Yonge St .may also be warranted, at an estimated cost of $200,000.

2.1.7 CYME Software Applications **_IK154_**

Project SP8: Purchase of Additional Modules (2008)

CYMCAP/OPT $ 3,450 + GST

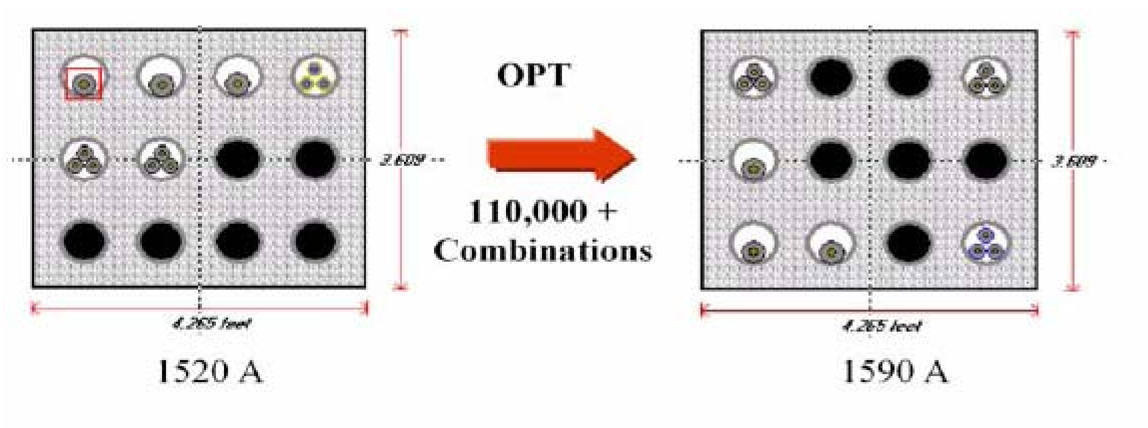
A power cable has only one temperature rating and only one voltage rating, but it has many ampacities depending on how and where it is used. The particular location of the cable relative to the other cables, makes a difference in the cable ampacity, especially when the cables are in ducts. The task is to determine the combination which provides the maximum cable ampacity.

The Duct Bank Optimizer (CYMCAP/OPT) is an add-on module to CYMCAP.This module allows the user to determine the placement of multiple circuits within a duct bank such that certain optimal criteria are fulfilled. The most common criteria is maximizing the duct bank overall ampacity. Another common criteria is maximizing the ampacity of any given circuit.

The Duct Bank Optimizer (CYMCAP/OPT) provides a fast and efficient method for analyzing various duct bank structures and cable combinations to determine the optimal cable ampacity. The results will show the various circuit disposition within the duct bank in order to achieve maximum ampacity, as shown in Figure 1, below.

Figure 1:

The condition illustrated below, shows the cable locations for maximum ampacity.



CYMDIST-RAMPRED-RAMHIST $ 12,650 + GST

Reliability assessment has become important for utility planners in recent years. Improved service reliability is motivated by government regulation, but providing superior service at an attractive price is in the interest of both the utility and the customer.

CYMDIST (RAM) is an add-on module to CYMDIST designed to aid distribution engineers in assessing the reliability of electric distribution networks. The program computes a set of predictive reliability indices for the overall system and their corresponding protection zones such as MAIFI, SAIFI, SAIDI, CAIDI, ASAI, ENS (Energy Not Supplied), AENS and LEI. It also computes customer point indices such as the frequency of interruption, the duration, etc., for each customer.

CYMDIST (RAM) provides a high degree of flexibility for analyzing various distribution system configurations ("what-if" scenarios). The effects of network modifications can be analyzed to measure the improvement in reliability indices by each capital project. It will help to justify capital expenditures. The reports include numerous graphical reports showing the reliability indices by color as well as customizable tabular reports.

CYMDIST-FORECASTER $ 11,500 + GST

Carrying out "what-if" scenarios with anticipated new loads and new devices is becoming more important for utility planners as capital dollars are becoming scarce and lead times for acquisition of major equipment is becoming longer. This new module (CYMDIST-Forecaster), allows users to create multiple scenarios of the base networks to analyze forecasted system changes.

CYMDIST-Forecaster is an add-on module to CYMDIST designed to aid distribution engineers in assessing the impact of changes to the network. The network scenarios that can be simulated range from validation of a planned switching scenario to a multi year modeling of the system forecasted changes.

The basis of the network forecaster module is to allow the user to create a series of modifications, insert a series of analysis at specific moments in the project and perform a simulation in batch mode throughout the project. The project modifications can be grouped by year or by any other user-defined grouping.

This module can only be used after the GIS-CYME Integration is completed and operational.

Total for the 3 modules = $ 27,600 + GST

2.2 RELIABILITY PROJECTS

2.2.1 Necessary Capital to Maintain System Integrity

Project R1: Conversion 13.8kV Amber MS F3 Feeder (2008) **SG134**

Markham TS#1 peaked at 94MW, exceeding the planned capacity of 80MW. The 22M5 and the 22M6 each exceeded 460A. It is recommended that the existing 13AMB-F3 line be converted to 27.6kV and connected to the 22M2 at Amber MS allow it to become a third 28kV three phase overhead circuit. The conversion will allow the 22M5 and 22M6 to be off-loaded to another 27.6kV feeder. The overhead F3 feeder will be tapped to the 28kV outside of the station.

This would be a 2008 project at an estimated cost of $1,391,000.

Project R2: Radial Supply Remediation (2008-2012) ***various***

In 2007, Planning prepared a report that reviewed radial supply situations in the 28kV distribution system. See the attachments for the complete report.

For the higher priority situations, recommendations to resolve them were developed. The selected segments, as noted in the report, are noted below in Table 3B, along with the initial estimates.

Estimates from design and the final slotted projects can be seen Table 3A. The estimates are considerably higher than those noted in the report.

TABLE 3A: RADIAL FINAL SUPPLY REMEDIATION ($000)

ITEM	2008	2009	2010	2011	2012
Segments R1, V1, M2,	$227				
Segments V5, V6, M3, M4, M6, V2		$3,882			
Segments R2, R4, V4, V7, M7, M8			$4,203		
Segments V8, M5, M9				$2,853	
Segments V9, M10, M11, M12, M1					$3,526
TOTAL ($14,691)	***$227***	***$3,882***	***$4,203***	***$2,853***	***$3,526***

TABLE 3B: INITIAL FINAL SUPPLY REMEDIATION ($000)

ITEM	2008	2009	2010	2011	2012
Segments R1, V1, V2, M1	$1,950				
Segments V5, V6, M3, M4, M6		$1,930			
Segments R2, R3, R4, V4, V7, M7, M8			$1,880		
Segments V8, M5, M9				$2,150	
Segments V9, M2, M10, M11, M12					$2,045
TOTAL ($9,955)	***$1,950***	***$1,930***	***$1,880***	***$2,150***	***$2,045***

Project R3: Rural /Urban Feeder Segregation
Also included in the report was a review of urban and rural segregation. One project was recommended for inclusion in the 2007 budget. If this work is not completed in 2007, it is recommended that it be completed in 2008.

Project R4: Plant with Suspected Problems (2008) ***KD***
A review of the plant with suspected problems did not occur in 2007. It is now planned to be undertaken in 2008. The areas noted that are believed to require remediation are shown below.

TABLE 4: SUSPECTED PROBLEMS REPAIRS

ITEM	2008	2009	2010	2011	2012
Segment A – Downtown Richmond Hill	$				
Segment B – Village Parkway		$			
Segment C -			$		
TOTAL					

2.2.2 Reinforcement of the Power System in areas of High Load Density
Project R5: Feeder Balancing ***KD***
The Approved Planning Philosophy dictates that feeders are to be planned to operate at 400A or

lower. In the summer of 2007, there were feeders that consistently exceeded these values under normal system configurations.

In the fall, feeders that peak above the 400A planning standard on a regular basis from May 1 to August 1, 2006 are identified. A plan is then developed to reduce the loading to be low the planning standard prior to the following year's peak season.

Typically, the balancing can be done with minimal costs, such as moving open points or changing taps. Although there are no capital costs, the cost for the work will be budgeted for by lines within their yearly standing work orders.

There are occasions, as noted below, where a distribution loop should be split to reduce its loading to rated limits.

It is assumed for budget purposes, that there will be one of these annually, such that for future years, it is assumed that similar funding will be required.

TABLE 5: PROPOSED 2008 WORK TO RESPECT 400A PLANNED FEEDER LIMIT

Feeder	2007 Peak Load (Amps)	Work to Be Done	Estimated Capital WO Cost
(A) 21M6	527A	***Split 1/0 loop at Hwy #7 and Weston Road – new u/g tap from 21M11 south of 30-L3 to switch 30-L207*** (This will be accomplished by installing 2 dip new poles and connecting to the existing gear.)	$234,000 *(SG133)*

Additionally, there are locations in the distribution system where additional manual switches are required to enhance ties between feeders. The 2009 locations have been identified, and similar dollars should be carried for future years. This is similar to the approach used in previous Aurora budgets.

TABLE 6: PROPOSED FUTURE WORK FOR FEEDER BALANCING/ TIES

ITEM	*2008*	*2009*	*2010*	*2011*	*2012*
(B) Aurora – re-conductor Mill St from 3/0 to 336 – build feeder tie between MS3 and MS1 **(SC131)**		$466,000			
(C) Aurora – Install LIS* between 4F1 and 4F2 **(SC132)**		$29,000	$	$	$
(D) Aurora – Install LIS* between 6F1 and 6F2 **(SC133)**	$29,000		$	$	$
(E) Aurora – Install LIS* between 4F2 and 1F3 **(SC134)**	$29,000		$	$	$
(F) Install 44kV Transfer Switch arrangement at MS#6 – allows MS#6 to be placed on 2 different 44kV feeders **(SC135)**	$53,000		$	$	$

***Note:** Design to select location with consultation from operations.

2.2.3 Distribution Automation

In 2006, Planning released a draft report on Distribution Automation. This report quantified the rationale for installation of remote switches.

Project R6: Automated Switches ***TB127***

Based on the report, there should be 68 switches added to the distribution for reliability purposes, with 6 of these completed in 2007:

TABLE 7: PROPOSED DISTRIBUTION AUTOMATION

ITEM	*2008*	*2009*	*2010*	*2011*	*2012*	*TOTAL*
Number of Automated Switches	12 $1,075	12 $1,075	12 $1,075	12 $1,075	14 $1,254	***62***

A single unit is estimated at $90,000 per switch.

The criteria noted justifying the automation can be defined, in summary form, as:

Customers – where the customers km per segment exceed 8,145. This number is supported by the calculations in the Distribution Automation report, and it essentially means that the 8,145 limit should be respected where the distance, in km, multiplied by the number of customers in that distance exceeds 8,145.

Loading – where feeders are over 300A, the feeder should be segmented so that the excess amperage can be split amongst one or more feeders.

Operations – where System Control would recommend an automated switch based on operational flexibility.

2.2.4 Feeder Projects

Project R7: North Lake Road (2008) ***TB 106***

It is recommended that the 1 phase line along North Lake Road to converted to a 3 phase line. This will provide an additional 28kV east / west backup, and provide a tie between the 27M1 and the 27M8 feeders.

This would be a 2008 project at an estimated cost of $76,000.

Project R8: Yonge and Weldrick ***SG126***

It is recommended that at Yonge St., a 27.6kV crossing be established between the overhead feeders on the east and the west side of Yonge s/o Major Mackenzie Dr. This will change an overhead feeder on the west side from the existing lateral condition to part of a main feeder. This will eliminate series fuses on west side. An open point is recommended to be established between Petro Canada and Pizza Hut on Yonge at Weldrick.

This would be a 2008 project at an estimated cost of $87,000.

2.3 CAPACITY PROJECTS

2.3.1 Grid Projects Required for Integration of Vaughan TS#1E

When the planning for the feeder integration for TS#1E transpired, several circuit additions were proposed for 2007 and 2008. These are still recommended.

Project C1: Dufferin St. from Rutherford Rd. to Major Mack Dr. (2008) ***SG117***

This project adds 1 circuit to an existing pole line. It provides a double circuit line to border area V11 that is under development.

This would be a 2008 project at an estimated cost of $.

Project C2: Major Mack Dr , from Dufferin St. to Bathurst St (2008) ***SGKD124***

This project adds 1 circuit to an existing pole line. It provides a double circuit line to border area V11 that is under development.

This would be a 2008 PROBABILITY project at an estimated cost of $379,000.

Project C3: Dufferin St. from Greenwood TS. to Centre St. (2008) ***JNKD118***

This project constructs new feeders, the 20M23 and the 20M24, and integrates these into the grid.

This would be a 2008 PROBABILITY project at an estimated cost of $2,136,000.

Project C4: Centre St, from Dufferin St. to Bathurst St. (2008) ***JNKD119***
This project constructs new feeders, the 20M23 and the 20M25, and integrates these into the grid.

This would be a 2008 PROBABILITY project at an estimated cost of $2,313,000.

Project C5: Centre St. from Yonge St. East to Yonge St. West (2008) ***TB102***
This project extends the pole line that takes the 20M9 and 20M10 into Markham, providing a tie between Greenwood TS, Richmond Hill TS and Leslie TS.

This would be a 2008 PROBABILITY project at an estimated cost of $810,000.

2.3.2 Grid Projects Required for Integration of Transformer Stations

A) MARKHAM
Markham TS#4 is planned for an in-service date of late in 2009 or early 2010. The location of the station is not known at this time, and will likely not be known until sometime in 2008.

Construction of feeder lines should commence in 2009 and all feeders completed in Q1 of 2012.

Previous stations, plus feasibility studies for previous station, indicate that allowing for $7,000,000 for feeder integration would be reasonable, however, given the location on the Parkway Belt, the congestion and requirement for underground feeders has driven the estimate up to approximately $20,000,000. This has been split over several years.

(A) Allow for $7,500,000 in 2009
(B) Allow for $3,900,000 in 2010
(C) Allow for $2,900,000 in 2011
(D) Allow for $6,700,000 in 2012. (total of $21,000)

In the budget system, the following monies have been included:
(A) $4,969,000 in 2008
(B) $4,970,000 in 2009
(C) $4,972,000 in 2010
(D) $4,972,000 in 2011 (total of $19,883)

B) VAUGHAN
Vaughan TS#4 is planned for an in-service date of between 2012 and 2015, depending on CDM initiatives (currently believed to be 2013). The location of the station is not known at this time, and will likely not be known for several years.

Construction of feeder lines should commence in 2012, and be completed for 4 feeders in Q1 of 2013. This is work from the end of the TS#4 feeder egress (included in the budget) to the connection point in the existing system form this project, plus feeder integration out in the distribution system.

Similar costing to Markham TS#4 is contemplated, allowing for inflation.

Project C8*: *Vaughan TS#4 Feeder Egress

KD

(A) Allow for $7,500,000 in 2012
(B) Allow for $4,000,000 in 2013
(C) Allow for $3,000,000 in 2014
(D) Allow for $7,000,000 in 2015.

In the budget system, the following monies have been included:
(A) $5,372,000 in 2011
(B) $4,205,000 in 2012

2.3.3 Grid Projects Required for Integration of Armitage Feeders (Holland Junction TS)

Holland Junction TS has an anticipated in-service date of early summer 2009.

Once completed, both Newmarket Hydro and Hydro One will be transferring feeders from Armitage TS to Holland Junction. Once their transfer is completed, work at Armitage TS is needed to connect the new Aurora 44kV feeders.

The entire supply project will be split in two – work outside Armitage TS, and work inside Armitage TS.

The initial estimates for this work were done in 2005. Since that time, some 44kV line construction within Aurora has transpired. The same methodology used in 2005 has been applied using 2006 typical per km costs for single, double, triple and quad circuit construction.

Project C9: Aurora 44kV Line Work (2009) ***SC129***

In 2009, the feeder work outside Armitage TS should transpire. This has been planned as 44kV feeder construction for the two feeder positions being provided to PowerStream Inc. by Hydro One and Newmarket Hydro from Armitage TS. See the reference drawings for a schematic representation of the work.

The costs are estimated to be $5,824,000 in 2009.

Project C10: Armitage TS 44kV Work (2009) ***SGKD115***

There is considerable work required by Hydro One and Newmarket Hydro to rearrange feeder configurations within the station to make the two feeders useable for PowerStream Inc. The work is based in discussions with the other two utilities in 2005, and it will be constructed by Newmarket Hydro, funded by PowerStream Inc.

This would be a 2009 project at an estimated cost of $5,198,000.

Project C11: Gormely TS 44kV Work (2012) ***SC136***

Included in the OPA long term plans for Northern York Region supply is another 230/44kV station in 2011. The location of the station is not known at this time, and will likely not be known for several years. This station would provide feeders at 44kV as it will service northern York Region. Assume that PowerStream will obtain 2 feeder positions, and that these may be 6km in length, double circuit construction north into Aurora.

Construction of feeder lines should commence in 2011 and be completed in Q1 of 2012.

The costs are estimated to be $5,900,000.

2.3.4 Grid Projects to Improve Feeder Ampacity

In 2006, the CYME program was used to calculate feeder egress ampacities. It was determined that the several transformer station feeder egress ratings could be increased with remedial construction.

Project C12: Hold open

Project C13: Vaughan TS#2 – Torstar Feeders (2011)

The 2 Torstar feeders (M1 and M12) supply less than 5MW of load.

In 2007, a plan was reviewed and identified to tap these feeders to allow an additional 10MW to be integrated into the distribution system.

This project would see the dedicated feeders split such that they could be also used in the distribution system.

This project was not recommended to be done as there are technical restrictions.

Project C14: Vaughan TS#2 – Additional Feeders from Existing Stations (2009)

SG135

In the fall of 2006, Planning prepared a report titled *"Vaughan TS Feeder Egress Ampacity Calculation"*. This report identified some feeders that required assistance to achieve higher ampacities.

This project would utilize the existing TS#2 M2 feeder breaker position and add one feeder from the TS to Steeles Ave., approximately 1 km, then go east on Steeles to Jane St..

During the June 2007 peak period, the loading on 5 out of the 11 feeders exceeded the feeder rating. A transfer of about 200 amps will be required to bring the 5 feeders within their calculated rating. The 2006 feeder peak loading and June 2007 is shown in Table 7 below.

Table 7: Vaughan MTS2 Feeder Loading

Vaughan MTS#2 Feeder Loading					
TS Name	Feeder ID	Calculated Rating (A)	2006 Coincident Feeder Peak (A)	June 2007 Coincident Feeder Peak (A)	Remarks
VTS2	M1	428	50	52	Torstar Feeder
	M2				Spare Breaker Position
	M3	Assume 600 A	440	364	O/H Feeder
	M4	428	518	458	
	M5	428	373	475	
	M6	428	466	527	
	M7	428	308	333	
	M8	428	473	453	
	M9	428	465	437	
	M10	428	388	398	
	M11	428	284	414	
	M12	428	54	64	Torstar Feeder

The costs are estimated to be $3,772,000 in 2009.

Project C15: Transformer Station Feeder Egresses (2008-2010) ***KD***

Reports were completed in 2006 and 2007 that reviewed the current ampacities for the station feeders, and recommended changes to those that were not high enough.

Changing the bonding method from two-point bonding to single-point bonding by adding two separate neutrals to the duct bank containing M7, M8, M11 & M12 feeders, open the concentric neutral at the riser-end and terminate with a 3kV arrester were recommended at Vaughan TS#1.

The calculated ampacity rating of these circuits with the existing two-point bonding is 377 amps. By changing the bonding to single-point bonded, the rating will be increase from 377 amps to 550 amps.

The Markham stations were recommended for inclusion in the 2007 budget, but were not approved due to resource constraints. This project would change the installation of the neutrals to eliminate circulating currents resulting in an increase of feeder ampacities. The Vaughan and Richmond Hill egresses are now added.

TABLE 8: TRANFORMER STATION EGRESS REMEDIATION

ITEM	*2008*	*2009*	*2010*	*2011*	*2012*	*TOTAL*
Transformer Stations	VTS#1 $36,000 MTS#3 $119,000 **(A)**	RHTS#1 MTS#2 $123,000 **(B)**	RHTS#2 MTS#1 **(C)**			

2.3.5 Requirements due to Development and Growth

Project C16: Kleinburg Feeder Utilization (2008) ***SC130***

In order to fully utilize all of the low voltage supplies within the PowerStream service territory, the two existing Kleinburg feeders (45M3 and 45M4) require construction work prior their ability to provide capacity.

It is proposed that feeder 22M5 from Huntington Rd. n/o Rutherford Rd. be re-rerouted to Huntington Rd. s/o Rutherford Rd. to Langstaff Rd. This will allow us to use the HONI's feeders (30MVA), supply new load, and accommodate load transfers and greater system reliability. Rerouting will fit in for future TS3 service needs.

During the 2006 peak load period, 2 out of the 10 feeders exceeded the feeder rating. A load transfer will be required to bring the 2 feeders within their calculated rating.

The utilization of the Kleinberg feeders will provide the required capacity relief to the TS3 Feeders. The 2006 feeder peak loading is shown in Table 9, below.

Table 9: Vaughan MTS3 Feeder Loading

Vaughan MTS#3 Feeder Loading					
TS Name	Feeder ID	Calculated Rating (A)	2006 Coincident Feeder Peak (A)	June 2007 Coincident Feeder Peak (A)	Remarks
VTS	M		0	0	Spare Breaker Position
	M		0	0	Spare Breaker Position
	M	471	158	78	
	M	471	358	195	
	M	471	219	405	
	M	471	187	214	
	M	471	355	458	
	M	471	451	356	
	M	471	452	427	
	M1	471	442	409	
	M1	471	488	458	
	M1	471	483	134	
	M1		0	0	Spare Breaker Position
	M1		0	0	Spare Breaker Position

This would be a 2008 PROBABILITY project at an estimated cost of $777,000.

Project C17: 44kV Feeders for OEB Sanctioned Embedded Generators (2012) TBKD116

If the RFP for supply to Northern York Region is issued by the OEB, there is likelihood that one proponent will earn the right to generate electricity that will be connected to the 44kV system and to Armitage TS. Currently, the OPA has not indicated a willingness to continue with this project, but has not ruled out the idea for the future.

Monies should be reserved for construction of pole lines to facilitate connections in the event this does transpire. This would be a 2012 project at an estimated cost of $4,205,000, based on the fact that PowerStream Inc. would either be required to fund the project, or be a willing partner in the project. It is presumed that there would be three 44kV feeders installed from the location of the generation to the connection points in the sub-transmission system with remove and replace construction where required.

Project C18: Denison Ave. from Warden to Esna Park (2009) JN130

It is recommended that two three phase overhead circuits be installed on Denison Ave. In 2006, Markham TS#1 peaked at 94MW, exceeding the planned capacity of 80MW. The 22M5 and the 22M6 each exceeded 460A. The extension will allow the 22M5 and 22M6 to be off-loaded to Markham TS#3. This project will likely be required to be underground.

This would be a 2009 project at an estimated cost of $3,121,000.

Project C19: Double cct 16th Ave, 9th Line to Reesor Rd. (2009) **JN139**

The updated Cornell Secondary Plan estimated approx. 38,000 people in 14,500 residential units, and 11,000 to 13,000 jobs.

The existing feeders on 16th Ave is a non-standard 3/0 three phase feeder. It is recommended to upgrade the supply to a double cct on 16th Ave to allow for increased capacity and improve supply reliability for the surrounding developments.

This would be a 2009 project at an estimated cost of $1,191,000.

Project C20: 14th Ave., 9th Line to Reesor Rd. (2011) **JN140**

The Box Grove Community is bounded by Highway 407 to the north, the CP Havelock Rail Line and Reesor Road to the east, the CN York Rail Line to the south, and 9th Line and the Rouge River to the west. It will accommodate approximately 2,600 dwelling units with approximately 10,000 people.

14th Ave is in the middle of Box Grove Development. The existing feeder is single phase. A new three feeder on 14th Ave. will increase supply capacity, form a feeder loop around Box Grove and improve reliability.

This has been moved to be a 2011project at an estimated cost of $4,423,000. It was originally stated as a 2009 project.

Project C21: Double cct Reesor Rd., 14th Ave. to 16th Ave. (2012) **JN141**

The updated Cornell Secondary Plan estimated approx. 38,000 persons in 14,500 residential units, and 11,000 to 13,000 jobs. Box Grove will accommodate approximately 2,600 dwelling units, approximately 10,000 persons.

The existing feeders on Reesor Rd. is 3/0 three phase feeder. Double cct on Ressor Rd. will increase capacity to those two developments, form a feeder loop around Box Grove/Cornell, and improve supply reliability.

This has been moved to be a 2012 project at an estimated cost of $4,157,000. It was originally stated as a 2009 project.

3.0 SUMMARY

TABLE 10: ANTICIPATED CAPITAL SPENDING for 2008 to 2012.

Category & Project Description	2008 BUDGET	2009 BUDGET	2010 BUDGET	2011 BUDGET	2012 BUDGET
Special Projects					
IK101 - SP1: Asset Condition Assessment					
a) Consultant fees	$164,				
b) Capital Assets	$2,000	$5,300	$8,900	$8,900	$8,900
IK132 - SP2: 75/125 MVA Spare Transformer	$2,700,				
IK150 - SP3: 50/83 MVA Spare Transformer		$2,500			
IK151 - SP4: TS#4 Vaughan Land			$1,000		
IK152 - SP5: TS#5 Markham Land					$4,000
IK153 - SP6: IESO Connection Assessment				$25	
IK131 - SP7: Purchase of Hydro One Feeders		$400			
IK154 - SP8: CYME Software	$27				
Sub-total	**$4,891**	**$8,200**	**$9,900**	**$8,925**	**$12,900**
Reliability Projects					
SG134 (KK) - R1: Conversion of 13.8kV Systems	$1,391				
(All) - R2: Radial Supply Remediation	$227	$3,882	$4,203	$2,853	$3,526
R3: Rural/Urban Feeder Segregation					
R4: Plant with Suspected Problems					
(All) - R5: Feeder Balancing	$345	$495			
TB127 (JT) - R6: Distribution Automation	$1,075	$1,075	$1,075	$1,075	$1,254
TB106 (WH) - R7: North Lake Road	$76				
SG126 (SW) - R8: Yonge & Weldrick	$87				
Sub-total	**$3,201**	**$5,452**	**$5,278**	**$3,928**	**$4,780**
Capacity Projects					
SG117 - C1: Dufferin, Rutherford to Major Mac					
SGKD124 (IH) - C2: Major Mac, Dufferin to Bathurst	$379				
JNKD118 (BG) - C3: Dufferin, VTS#1 to Bathurst	$2,136				
JNKD119 (BG) - C4: Centre, Dufferin to Bathurst	$2,313				
TB102 (WH) - C5: Centre, Yonge St.	$810				
KD113 (MC)- C6: Markham TS#4 Feeder Egress Part 1		$7,500	$3,900		
KD (MC)- C7: Markham TS#4 Feeder Egress Part 2				$2,900	**$6,700**
KD (MC)- C8: Vaughan TS#4 Feeder Egress					**$7,500**
SC129 (BL) - C9: Aurora 44kV Line Work		$5,824			
SGKD115 (SW) - C10: Armitage TS Work		$5,198			
SC136 - C11 (BL) : Gormely TS 44kV Work		$5,900			
C12: hold open					
C13: cancelled					
SG134 - C14 (KK): Increase VTS#2 Fdr Capacity		$3,772			
KD (WH) - C15: Markham TS Feeder Egresses	$155				
SC130 (MP) - C16: Kleinburg TS Feeder Utilization	$777				
TBKD116 (WH)- C17: 44kV Work for the Embedded Generator					$4,205
JN130 (MC) - C18: Denison, Warden to Esna Park		$3,121		$4,423	
JN139 (BG) C19: 16th Ave, 9th to Reesor		$1,191			
JN140 (BG) C20: 14th Ave, 9th to Reesor					$4,157
JN141 (BG) C21: Reesor Rd, 14th to 16th					
Sub-total	**$6,570**	**$32,506**	**$3,900**	**$7,323**	**$22,562**
TOTAL DOLLARS (000)	**$14,662**	**$46,158**	**$19,078**	**$20,176**	**$40,242**

COLOUR CODE: Orange – estimates provided by Planning, Black – estimates provided by Design

TECHNICIANS (All = all have at least one, MC = Matt, BG = Bruce, WH = Warren, BL=Bill, JT=Joe, SW=Stew)

Five Year Capital Work Plan
Station Design & Construction
System Planning Division
2008 - 2012

Prepared by: *Glenn Allen, P. Eng.*
Manager, Station Design & Construction

Reviewed by: *Ted Wojcinski, P. Eng.*
Director, Engineering Planning

February 12, 2008 Station Design & Construction

5 Year Capital Work Plan, Station Design & Construction 2008-2012

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EXECUTIVE SUMMARY

Selected projects are recommended by Station Design for implementation for the two-year period of 2007 and 2008.

The projects have been categorized as:

- Special Projects
- Reliability Projects
- Capacity Projects
- Unbudgeted Projects

The forecasts for the dollar requirements on a yearly basis are shown in Table 1.

TABLE 1: SUMMARY OF TOTAL RECOMMENDED CAPITAL DOLLARS

Category	2008 BUDGET $000	2009 BUDGET $000	2010 BUDGET $000	2011 BUDGET $000	2012 BUDGET $000
Special Projects	$1,932	$415	$295	$1,026	$143
Reliability Projects	$2,045	$277	$418	$2,912	$409
Capacity Projects	$7,720	$11,285	$1398	$4,519	$17,820
Unplanned Projects	$0	$0	$0	$0	$0
TOTAL DOLLARS	**$11,697**	**$11,977**	**$2,111**	**$8,097**	**$18,372**

1.0 INTRODUCTION

1.1 Background

Selected projects are recommended by Engineering Planning for completion for the Five-year period of 2008 to 2012.

The projects have been categorized as:

- Special Projects
- Reliability Projects
- Capacity Projects
- Unbudgeted Projects

The majority of capital work originates from growth in the City of Vaughan, Towns of Markham, Richmond Hill and Aurora, the Region of York.

Work recommended in this document support projects that are not, in general, driven by direct legal need, governmental or regulatory bodies, and for those that have not been dictated as a requirement, they have been previously considered “discretionary” projects. These projects are aimed at improvements to system reliability and for providing additional capacity.

1.2 Purpose

This report provides the background support and justifications for projects, specifically;

f) detailing all projects Station Design has identified to complete;
g) providing budgetary estimates of the recommended projects;
h) providing an overview of the scope of each of the projects; and
i) providing a summary of the total estimated recommended costs by category.

1.3 Project Selection Process

Projects are selected for implementation, as follows:

a) Projects with a value less than $250,000 require a detailed summary and are approved on the basis of achieving reliability targets, meeting statutory requirements or providing needed capacity.
b) Projects with a value greater than $250,000 require a formal business case for approval.

PROJECTS

2.1 SPECIAL PROJECTS

Each year, there are a number of issues that arise resulting in initiatives to provide solutions. These are listed below.

2.1.1 Transformer Stations

Project SP1: Install Capacitor Banks at Torstar TS (2008) ***GA105***

This project is to install capacitor banks at Torstar TS to meet IESO power factor requirements. The scope of the project includes Installation of two 20MVAR outdoor, externally fused, capacitor banks, two 28kV indoor breakers as well as associated cables & ductwork.

The approximate cost of the two units is $1,047,000, including burdens.

Project SP2: Site Drainage Improvement - Markham TS #2 (2008) ***GA206***

Drainage at Markham TS #2 is poor. Recent changes to fill in low lying land on the adjacent property have made the situation worse. A study to determine the best course of action was completed in 2007.

The scope of this project will be to improve water drainage at the Markham TS #2 site. Completion of this project will permit the new Markham TS #4 to be built on this site. This will be a 2008 project at an estimated cost of $208,000, including burdens.

Project SP3: On-line Monitoring of Transformer Oil (2008-2013)
GA201, GA301, GA401, GA501 & GA601

This project will provide real time transformer gas in oil telemetry to PowerStream's control room and to Station Maintenance staff. This on-line gas in oil analysis is currently implemented at Richmond Hill TS #1 & #2 and Vaughan TS #3, but is not implemented at Markham TS #1, #2 & #3 or at Vaughan TS #1 & #2. The scope of this project will be to provide transformer gas-in-oil telemetry and analysis for the transformers at Markham TS #1, #2 and #3 as well as Vaughan TS #1 and #2.

The gas in oil monitoring and analysis equipment will be installed over a six year period between 2008 and 2013. The expected costs, including burdens, are shown below in Table 2:

Table 2 – Summary of On-Line Transformer Oil Monitoring Project Costs

Year	Station	Cost
2008	Markham TS #1 – T1 & T2	$129,000
2009	Markham TS #3 – T1, T2, T3 & T4	$219,000
2010	Vaughan TS #1 – T1 & T2	$137,000
2011	Vaughan TS #1 – T3 & T4	$141,000
2012	Vaughan TS #2	$143,000
2013	Markham TS #2 – T1 & T2	$145,000

Project SP4: On-line Monitoring of Markham & Richmond Hill TS Transformer Temperature (2009-2010) GA302 & GA402

This project will provide real time transformer temperature monitoring and telemetry to PowerStream's control room and to Station Maintenance staff. On-line transformer temperature monitoring is currently implemented at Vaughan TS #1, #2 & #3, but is not implemented at Markham TS #1, #2 & #3 or at Richmond Hill TS #1 & #2. The scope of this project will be to provide transformer temperature telemetry for the transformers at Markham TS #1, #2 and #3 as well as Richmond Hill TS #1 & #2.

The transformer temperature monitoring and telemetry equipment will be installed over a two year period between 2009 and 2010. The expected costs are shown below in Table 3:

Table 3 – Summary of On-Line Transformer Temperature Monitoring Project Costs

Year	Station	Cost
2009	Markham TS #1, #2 & #3	$330,000
2010	Richmond Hill TS #1 & #2	$196,000

Project SP5: Connect Jackson TS and Lazenby TS to Town Water & Sewage (2010) GA406

At present there is no washroom facility at Lazenby TS #1 & #2 and the sewage at Jackson TS is stored in a holding tank.

The scope of this project will be to:

1. Connect Jackson TS to town water & sewage and eliminate the sewage holding tank, if water and sewage are available.
2. Connect Lazenby TS #1 to town water & sewage and install washroom facilities.

This will be a 2010 project at an estimated cost of $158,000, including burdens.

Project SP6: Install Capacitor Banks at Markham TS #2 (2011) GA502

This project is to install capacitor banks at Markham TS #2 to meet IESO power factor requirements. The scope of the project includes Installation of two 20MVAR outdoor, externally fused, capacitor banks, two 28kV outdoor breakers as well as associated cables & ductwork.

The approximate cost of the two units is $885,000, including burdens.

2.1.2 Operations Communications

Project SP7: Cyber Security-Operations Communications (2008) GA108

The purpose of this project is to improve the security of operations communications to meet the North American Electricity Reliability Council (NERC) Critical Infrastructure Protection (CIP) cyber security standard. A consultant would be engaged to conduct a cyber security review. Procedures will be developed and a cyber security system will be installed.

This will be a 2008 project at an estimated cost of $111,000, including burdens.

Project SP8: Relocate Markham control room Radio Communications to MTS #3 (2008) GA203

The purpose of this project is to facilitate the relocation of PowerStream staff out of 8100 Warden Avenue by relocating the Markham control room Radio Communications from 8100 Warden Ave. to MTS #3.

The scope of the project includes:

1. Erection of a 100 foot radio tower at Markham TS #3,
2. Relocation of the operations 400MHz voice radios and SCADA 400 & 900MHz digital radios to Markham TS#3,
3. Removal of the 8100 Warden Ave. SONET node and
4. Rerouting leased communication circuits currently terminating at 8100 Warden Ave. to MTS #3.

This will be a 2008 project at an estimated cost of $107,000, including burdens.

2.2 RELIABILITY PROJECTS

2.2.1 Transformer Stations

Project R1: Greenwood TS Feeder Protections & RTU Replacement (2008) GA103

Replace the aging ASW RTU and ABB DPU feeder protection relays at Greenwood TS with a new RTU, HMI and feeder protection IED's. The new RTU would use the new IED's for SCADA inputs and outputs on the feeders. The new HMI would link to the new feeder IED's and to the HMI in the Greenwood TS expansion so that both halves of the station could be monitored and controlled from either relay room. Engineering would be contracted out installation would be by P&C.

This project is expected to be completed in 2008 at an estimated cost of $401,000.

Project R2: Protection upgrade - Richmond Hill TS #2 (2012) GA107

This project was initiated in response to problems with and lack of manufacturer support for the existing Alstom protection relays at Lazenby TS #2.

The project scope includes the following; upgrade Bus, Line & Transformer protections and install new Human Machine Interface (HMI) at Lazenby TS #2. Upgrade Feeder protections at Lazenby TS #2 and install new HMI in Lazenby TS #1 in. Engineering would be provided by an engineering consultant, installation to be completed by P&C.

The project is expected to be completed in 2012 at an estimated cost of $409,000, including burdens.

Project R3: High Set Instantaneous Feeder Protection - Markham (2010-2011) GA403 & GA503

This project was initiated, because Markham TS #1 & # 2 feeder protections do not have high set instantaneous elements (50a). The feeder protections at these two stations are also an older design that cannot accept the settings required to implement PowerStream's Trip Saving protection philosophy.

The scope of this project is to replace the feeder protections at Markham TS #1 in 2010 & TS#2 in 2011.

The 2010 project cost is estimated at $115,000, and the 2011 project cost is estimated at 116,000, including burdens.

Project R4: Transfer Trip - Jackson TS (2008) ***GA205***

Replace the existing remote trip line protection with transfer trip facilities. Transfer trip signals would be transmitted to Parkway TS over the PowerStream SONET ring. Hydro One would cascade the transfer trip signals from Parkway TS to Richview TS and Claireville TS by means of their SONET ring.

This project was initiated because:

i) Hydro One is refurbishing their existing remote trip line protection with transfer trip facilities at Claireville TS and PowerStream will need to install new transfer trip equipment at Jackson TS to be compatible with Hydro One.

ii) Migrating to the new transfer trip facility will improve the reliability of the 230kV line protection at Jackson TS.

This project is expected to be completed in 2008 at an estimated cost of $164,000, including burdens.

Project R5: Transfer Trip - Greenwood TS and Torstar TS (2009) ***GA111***

Replace the existing remote trip line protection with transfer trip facilities. Transfer trip signals would be transmitted to Parkway TS over the PowerStream SONET ring. Hydro One would cascade the transfer trip signals from Parkway TS to Richview TS and Claireville TS by means of their SONET ring.

This project is expected to be completed in 2009 at an estimated cost of $277,000, including burdens.

Project R6: Backup Station Service Lazenby TS (2010) ***GA405***

This project was initiated to permit a single back-up generator to provide station service power to both Lazenby TS #1 and to Lazenby TS #2. Lazenby TS#2 has already been equipped with an external generator connection facility. A cable trench has been constructed between the two station control buildings. All that remains is to provide a connection between the station service panels in each building.

The scope of this project is to install a backup AC station service connection from Lazenby TS #2 to Lazenby TS #1

This project is expected to be completed in 2010 at an estimated cost of $24,000, including burdens.

Project R7: Torstar TS Feeder Protection Upgrade (2010) GA407

Replace the aging ABB DPU feeder protection relays at Torstar TS with a new HMI and feeder protection IED's. The new HMI would link to the new feeder IED's providing analog & digital telemetry and remote control for the control room via the SCADA master. Engineering would be contracted out installation would be by P&C.

This project is expected to be completed in 2010 at an estimated cost of $279,000.

2.2.2 Municipal Stations

Project R8: Replace Reclosers and 13.8kV Bus at Aurora MS #1 (2008) GA208

This project was initiated as a result of numerous outages, in 2006 and 2007, at Aurora MS #1. The outages were caused by problems on the 13.8kV bus and reclosers, as follows:

- A Red phase insulator failed on the secondary bus causing a lengthy station outage,
- The F2 recloser failed and was replaced by a similar vintage recloser borrowed from John MS in Markham,
- MS 1 is the only station with outdoor bus in Aurora and as such is susceptible to outages caused by animal related flashovers, and
- MS 1 is 39 years old and there is reason to believe the outdoor equipment may be reaching the end of its useful life.

The project scope includes replacing the existing outdoor 13.8kV bus and reclosers with enclosed switches and vacuum interrupters similar to the design of the new Aurora MS 7. The existing transformers, 44kV structures and SCADA RTU would be retained.

This project is expected to be completed in 2008 at an estimated cost of $1,120,000.

Project R9: Replace 2 Transformer Secondary Switches at Amber MS (2008) GA204

This project was initiated, because one pole of one of the existing transformer secondary switches was overheating and when it was operated the switch blade broke away from the mounting and fell to the ground below very close to the person on the end of the switch stick. It has been determined that these switches were not mounted properly because there is no support at the cable end to the transformers.

The project scope includes replacing the existing secondary switches on both transformers at Amber MS.

This project is expected to be completed in 2008 at an estimated cost of $90,000.

Project R10: Replace Rainbow MS or Install Pad Mount Transformer (2011) GA504

Rainbow MS is a single transformer MS that supplies 13.8kV load in the Woodbridge area. The customers supplied from Rainbow MS are fed radially and suffer the loss of reliability that radial supply imposes. Most of this load has been converted to 28kV as part of a radial remediation program.

However, approximately 1 MW of the 13.8kV load remains and has remained for a number of years. If the remaining 13.8kV load is converted to 28kV, Rainbow MS will be decommissioned and this project will be cancelled.

The scope of this project is to build a new 10 MVA MS on the existing Rainbow MS site or to install a pad mounted transformer. The cost estimate provided is for a new 10MVA MS this estimate will be revised if a different option is selected.

This project is expected to be completed in 2011 at an estimated cost of $1,398,000.

Project R11: Replace Concord MS or Install Pad Mount Transformer (2011) GA505

Concord MS is a single transformer MS that supplies 8.3kV load in the Concord area. The customers supplied from Concord MS are fed radially and suffer the loss of reliability that radial supply imposes. Much of this load has been converted to 28kV as part of a radial remediation program.

However, approximately 8 MW of the 8.3kV load remains and has remained for a number of years. If the remaining 8.3kV load is converted to 28kV, Concord MS will be decommissioned and this project will be cancelled.

The scope of this project is to build a new 10 MVA MS on the existing Concord MS site or to install a pad mounted transformer(s). The cost estimate provided is for a new 10MVA MS this estimate will be revised if a different option is selected.

This project is expected to be completed in 2011 at an estimated cost of $1,398,000.

2.2.3 Distribution Automation

Project R12: Reclosers Jackson TS Feeder 22M5 (2008) GA202

The reliability committee has identified, Jackson TS feeder 22M5 as having a very high number of outages. A plan has been put forward to install reclosers on this feeder to improve its reliability.

The 2008 project cost is estimated at $148,000, including burdens.

2.3 CAPACITY PROJECTS

2.3.1 Station Construction to Support Load Growth

Load growth in the PowerStream service area has made additional 230kV to 28kV and 44kV to 28kV transformation capacity necessary. The following project is recommended.

Project C1: New transformer station, to be built in Markham (2007-2009) GA100 & GA200

Markham TS#4 is planned for an in-service date of late 2009 or early 2010. The estimated cost for the new station is shown below in Table 4.

Station Component	Cost $000
Engineering Design	600
Approvals (EA, IESO, Permits)	50
Hydro One CCRA	70
Transformers	7700
28kV Switchgear	2425
Protection, Metering , Control	656
230 kV Switches	62
Primary Metering (Revenue)	184
Grounding Reactors	56
230kV Insulators	16
Station Service Transformers (2)	200
DC System	50
20MVAR Cap Banks (2)	276
28kV Cable	700
Site Supervisor	90
Civil Contract	2600
Electrical Contract	900
Commissioning	131
Construction Cost	**$16,766**
10% Contingency	$1,677
Subtotal	**$18,442**
PST	$1,475
Total Cost	**$19,918**

Table 4 – Markham TS #4 Estimated Component Costs

We originally planned for a 2009 in-service date. However, due to of uncertainties around land acquisition, the in-service date may be delayed to early 2010.

Work on the Markham TS #4 project started in 2007, and by the end of 2007 it is expected that $912,000 of the $19,918,000 total cost will be spent. If a site is acquired in time for a 2009 in-service date, we expect to spend $7,720,000 in 2008 and $11,285,000 in 2009. If a site is not acquired in time for a 2009 in-service date, but in time for a 2010 in-service date we expect to spend 7,027,000 in 2008, $9,698,000 in 2009, and $2,280,000 in 2010.

Project C2: New transformer station, to be built in Vaughan (2011-2013) GA500, GA600 & GA700

Vaughan TS#4 is planned for an in-service date of 2013. The estimated cost for the new station is shown below in Table 5.

Station Component	Cost $000
Engineering Design	675
Approvals (EA, IESO, Permits)	56
Hydro One CCRA	72
Transformers	8666
28kV Switchgear	2730
Protection, Metering , Control	738
230 kV Switches	70
Primary Metering (Revenue)	207
Grounding Reactors	63
230kV Insulators	18
Station Service Transformers (2)	225
DC System	56
20MVAR Cap Banks (2)	311
28kV Cable	788
Site Supervisor	101
Civil Contract	3000
Electrical Contract	1013
Commissioning	148
Construction Cost	**$18,937**
10% Contingency	$1,894
Subtotal	**$20,831**
PST	$1,666
Total Cost	**$22,497**

Table 5 – Vaughan TS #4 Estimated Component Costs

Vaughan TS#4 is planned for an in-service date of between 2012 and 2015, depending on CDM initiatives (currently believed to be 2013).

If a site is acquired in time for a 2013 in-service date, we expect to spend $4,159,000 in 2011, $17,820,000 in 2012, and $927,000 in 2013.

2.3.2 Projects Required to Support Growth in Aurora

Project C3*: *New Municipal Station, to be built in Aurora (2010) ***GA404***

PowerStream is planning to construct a new Municipal Station on the East side of Aurora to meet anticipated new demand. The station will be designated Aurora MS-9. The purpose of MS-9 will be to augment the 28kV supply from Aurora MS7 and MS8.

This project is expected to be completed in 2010 at an estimated cost of $1,398,000, including burdens.

2.4 UNBUDGETED PROJECTS

Each year, there are several projects which are required due to investigations resulting from agencies inquiries, unanticipated development or distribution system requirements that do not get budgeted for.

Additionally, there may be necessary expenditures as a result of the asset condition assessment project. Funds should be carried to allow for replacement or refurbishment as dictated by the reports.

Stations Design has not budgeted for any unbudgeted projects.

3.0 SUMMARY

Table 6 summarizes the capital spending anticipated for 2008 to 2012.

TABLE 6: SUMMARY OF TOTAL RECOMMENDED CAPITAL DOLLARS

WO SERIES	2008 BUDGET $	2009 BUDGET $	2010 BUDGET $	2011 BUDGET $	2012 BUDGET $
Special Projects					
SP1: Install Capacitor Banks at Torstar TS	$1,047,000	$0	$0	$0	$0
SP2: Markham TS#2-**Site drainage improvement**	$208,000	$0	$0	$0	$0
SP3: On-line Monitor TS Transformer Oil	$129,000	$219,000	$137,000	$141,000	$143,000
SP4: On-line Monitor TS Transformer Temp	$330,000	$196,000	$0	$0	$0
SP5: Jackson TS & Lazenby TS – Water & Sewage	$0	$0	$158,000	$0	$0
SP6: Install Capacitor bank at Markham TS #2	$0	$0	$0	$885,000	$0
SP7: Cyber Security – Operations Communications	$111,000	$0	$0	$0	$0
SP8: Markham Radio Communications	$107,000	$0	$0	$0	$0
Sub-total	$1,932,000	$415,000	$295,000	$1.026,000	$143,000
Reliability Projects					
R1: Greenwood TS Feeder Protections & RTU Replacement	$401,000	$0	$0	$0	$0
R2: Protection upgrade - Richmond Hill TS #2	$0	$0	$0	$0	$409,000
R3: High Set Instantaneous Feeder Protection – Markham	$122,000	$0	$115,000	$116,000	$0
R4: Transfer Trip - Jackson TS	$164,000	$0	$0	$0	$0
R5: Transfer Trip - Greenwood TS and Torstar TS	$0	$277,000	$0	$0	$0
R6: Backup Station Service – Lazenby TS	$0	$0	$24,000	$0	$0
R7: Torstar TS Feeder Protections	$0	$0	$279,000	$0	$0
Replacement	$1,120,000	$0	$0	$0	$0
R8: Reclosers & 13.8kV Bus - Aurora MS 1	$90,000	$0	$0	$0	$0
R9: Transformer Secondary Switches – Amber MS	$0	$0	$0	$1,398,000	$0
R10: Replace Rainbow MS	$0	$0	$0	$1,398,000	$0
R11: Replace Concord MS	$148,000	$0	$0	$0	$0
R12: Reclosers on Jackson TS Feeder 22M5					
Sub-total	$2,045,000	$277,000	$418,000	$2,912,000	$409,000
Capacity Projects					
C1: New transformer station, to be built in Markham	$7,720,000	$11,285,000	$0	$0	$0
C2: New transformer station, to be built in Vaughan	$0	$0	$0	$4,159,000	$17,820,000
C2: New Municipal Station, to be built in Aurora	$0	$0	$1,398,000	$0	$0
Sub-total	$7,720,000	$11,285,000	$1,398,000	$4,159,000	$17,820,000
Unbudgeted Projects	$0	$0	$0	$0	$0
TOTAL DOLLARS	**$11,697,000**	**$11,977,000**	**$2,111,000**	**$8,097,000**	**$18,372,000**

4.0 REFERENCE DOCUMENTS

Background information associated with the recommended projects is appended. These include:

a) Aurora MS1 Station Outage – Protection Coordination Review, October 29, 2006
b) PowerStream Corporate SONET Ring Bandwidth Use by Information Technology memo
c) Greenwood TS Water Infiltration Remediation Report, TSH Engineers.
d) 2008-2012 Capital Budget Detail Costs spreadsheets used to estimate capital costs

DRAFT

April 2009

PowerStream
Asset Condition Assessment
Technical Report

Phases 1, 2, and 3

Introduction

PowerStream, the third largest local electricity distribution company in Ontario, delivers power to more than 238,000 residential and business customers in the municipalities of Aurora, Markham, Richmond Hill, and Vaughan. PowerStream owns and operates distribution assets valued at approximately $617 million, including 4,294 km of underground cable and 17 municipal substations.

PowerStream is in the process of implementing an asset management program for its transmission and distribution assets. The program includes the development of Health Indices, risk-based economic analyses (probability of failure and criticality), and recommended Asset Sustainability Plans (replacements).

A key part of the asset management program is Asset Condition Assessment (ACA), involving collection and interpretation of condition and performance data to enable informed investment decisions. The primary purpose of the ACA is to detect and quantify long-term degradation, which would necessitate major capital expenditure. The result of the ACA is an optimized life-cycle plan based on real asset sustainability.

Asset Condition Assessment Framework

The general ACA framework is a two-step process consisting of Asset Evaluations and Program Development.

Asset Evaluations

The first step, Asset Evaluations, translates condition and criticality information into repeatable, quantitative measures.

<u>Health Index</u>

Asset Evaluations involves a technical condition assessment, wherein condition information is translated into a quantitative Health Index. The Health Index is based on information such as equipment age, historical utilization, maintenance, and visual inspections.

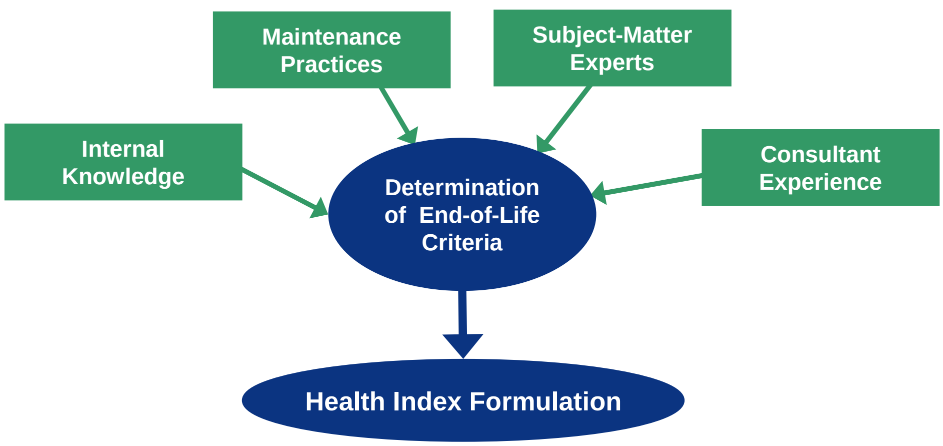

Figure 1. The Health Index establishes the condition of the asset population relative to end of life.

The Asset Evaluations step also includes defining the inputs for an asset risk assessment. Risk is calculated by multiplying asset failure probability times the consequence of asset failure. The failure probability is an annual failure rate, based on end of life failures. The consequence of asset failure is related to the criticality of the asset, is defined in dollar terms, and is intended to reflect the customers' perspective.

Failure Rate

The model includes failure probability curves, projecting failures as a function of age and type. The failure probability curve, or hazard rate, is a conditional probability; for example, the chance of a transformer failing at age 30 given it is 30 years old. The curves are based on the experience of PowerStream's technical experts. Over time, failure data may be collected to verify the assumed curves.

Failure probability can vary within an asset class. For example, different types of breakers (e.g., air, SF6, etc.) may have different failure probability curves. Because of this, the failure probability curve, and hence risk cost, for an asset may be different before replacement than after if replacement is not in-kind.

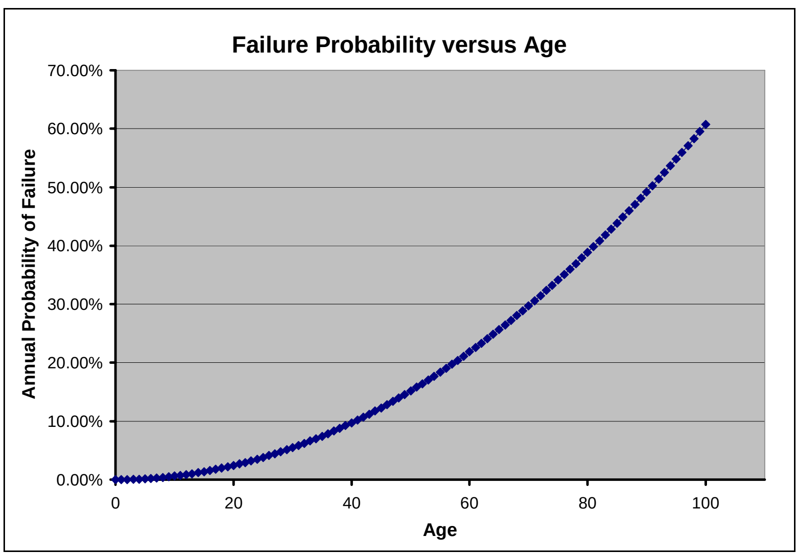

Figure 2. The failure probability curve projects conditional failure probability versus age.

Criticality

The consequences of an asset failure include the replacement cost of the failed asset and customer outage effects. The expected consequence may be the average of multiple failure scenarios, weighted by their relative probabilities. All costs must be expressed in dollar terms for consistent prioritization.

An asset management-based system of justifying expenditures must consider not only the direct costs to the utility, but also the costs to its customers in lost power and inconvenience. Customer outage costs can be estimated using a willingness to pay or willingness to accept method. The method evaluates outage consequences based on how much customers are willing to pay to avoid them, or what payment they would require to accept them. For this study it has been agreed to use the following, which can be altered at a later stage if better information is available.

- $20/kW of peak load for the customers interrupted
- $10/kW of peak load times the duration of the outage in hours

Risk Matrix

The risk matrix summarizes the condition and criticality of an asset. The risk matrix plots the current age failure probability versus the consequence of failure (criticality). The blue diamonds represent the entire asset population, while the red diamonds relate to the assets recommended for immediate intervention.

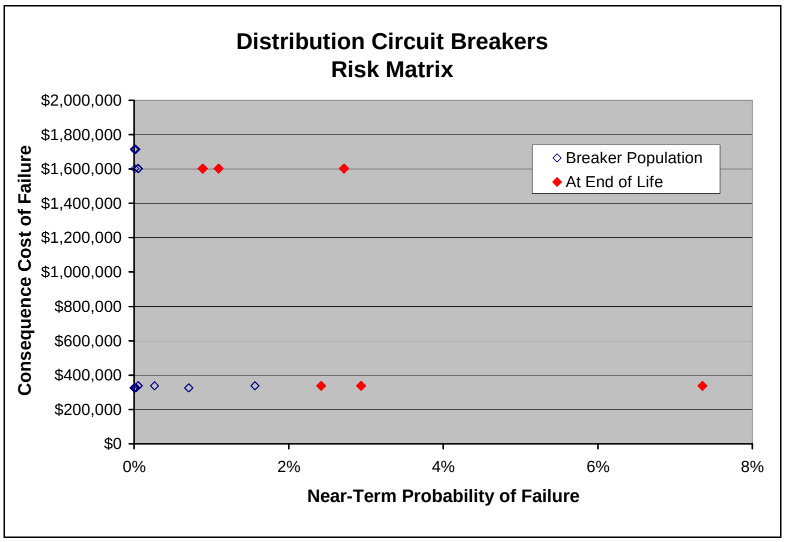

Figure 3. The risk matrix plots consequence cost of failure versus failure probability.

Program Development

The Program Development step involves defining intervention modes to mitigate asset risk, performing risk-based economic analyses to minimize asset life-cycle cost, and providing justification and prioritization for long-range spending.

Intervention Modes

Intervention modes are actions that can be done to mitigate asset risk, such as rehabilitation, replacement, monitoring, or purchase of spares. Intervention modes may affect the probability or consequence of failure.

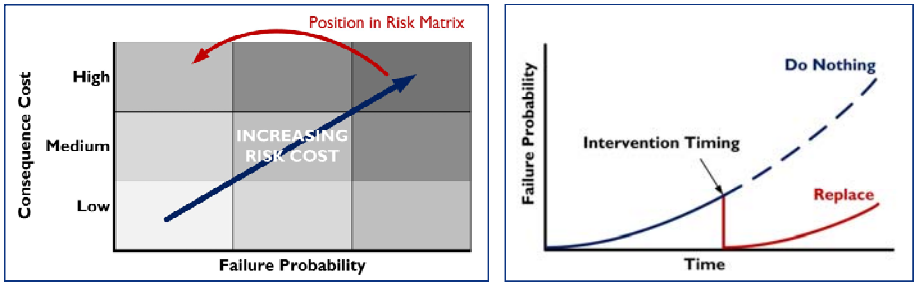

Figure 4. Effect of replacement on risk mitigation.

The simplest example is in-kind replacement, whereby an old asset with relatively high failure probability is replaced with a new one with lower failure probability.

<u>Risk-Based Economic Analysis</u>

The risk-based economic analysis determines the asset least life-cycle cost by balancing the risk of failure against the benefit of delaying capital expenditures.

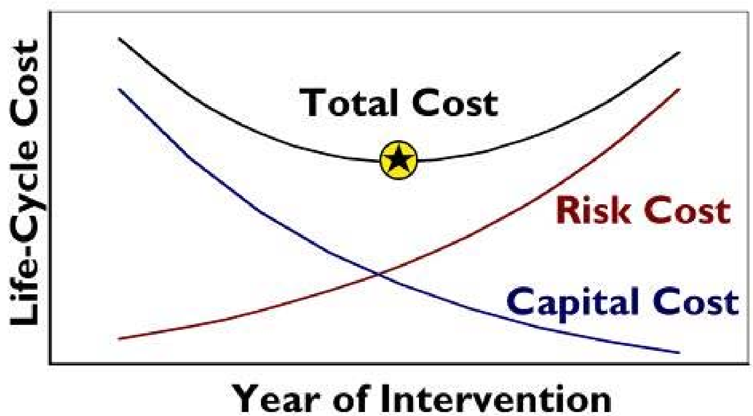

Figure 5. Life-cycle optimization.

The economic analysis methodology compares the available intervention alternatives to determine the lowest cost strategy (e.g., inject cable in 10 years, and then replace cable in 30 years). The methodology projects the performance effects of each strategy (i.e., mitigating failure probability or consequence of failure) to determine the optimal intervention timing.

The risk-based economic analysis methodology justifies spending decisions by determining the economically optimal timing of asset expenditures based on the associated asset risk profiles and related capital costs for interventions. Applying the same methodology to all the assets in an asset class produces a consistent spending program. The associated benefits and costs of delaying from the optimal timing provide the basis for a benefit/cost ratio for prioritization of limited resources.

Existing assets may be replaced with shorter-life assets. This means that the life-cycle cost of the new asset is different than the existing asset. The methodology in this case requires two steps, as shown in Figure 6.

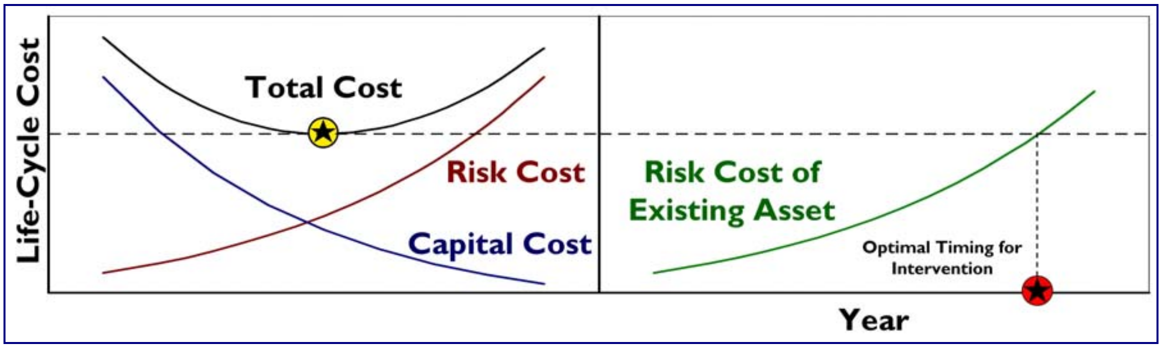

Figure 6 - Optimizing replacement timing of assets requires two steps: 1) Calculate the annualized life-cycle cost of the new asset; 2) identify the year in which the risk cost of the existing asset reaches this value. In that year, it is less expensive to replace the assets than to continue operating the existing asset.

Spending Justification and Prioritization

Limited resources should be directed toward programs with higher benefit/cost ratios. A benefit/cost ratio is calculated for all assets recommended for an intervention in the current or next year. In the case of asset replacements, benefit is the avoided cost of delaying replacement for one year. If an asset should be replaced this year, but replacement is delayed for one year, the incremental cost is the difference between the asset's risk cost and the annualized cost of the new asset. The graph below indicates the additional risk cost resulting from delaying intervention.

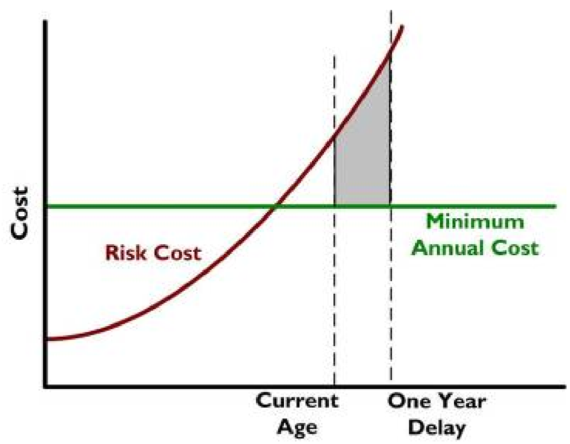

Figure 7. Incremental Benefit of Replacement this Year instead of Next Year.

The shaded area represents the net incremental benefit of replacement. This quantity is compared to the cost of the replacement to calculate benefit/cost ratio, which is used for prioritization.

Station Transformers – Asset Class Details and Results

Summary of Asset Class
Highly complex assets with a very high price per unit. Number of methods available to assess condition and status. PowerStream employs most of them which made detailed analysis of condition a relatively straightforward task. Risk analysis was more complex as redundancy needed to be addressed and different intervention options evaluated (most importantly levels of spares).

Data Sources Available
Comprehensive demographic and condition data was made available. Testing data available included DGA tests, standard oil tests and Doble power factor tests. Comprehensive load data was also provided which was useful both for condition and criticality assessments.

Demographics
Number of units: 20
Typical life expectancy (years): 50
Estimated replacement cost: $1.5 to 3 million

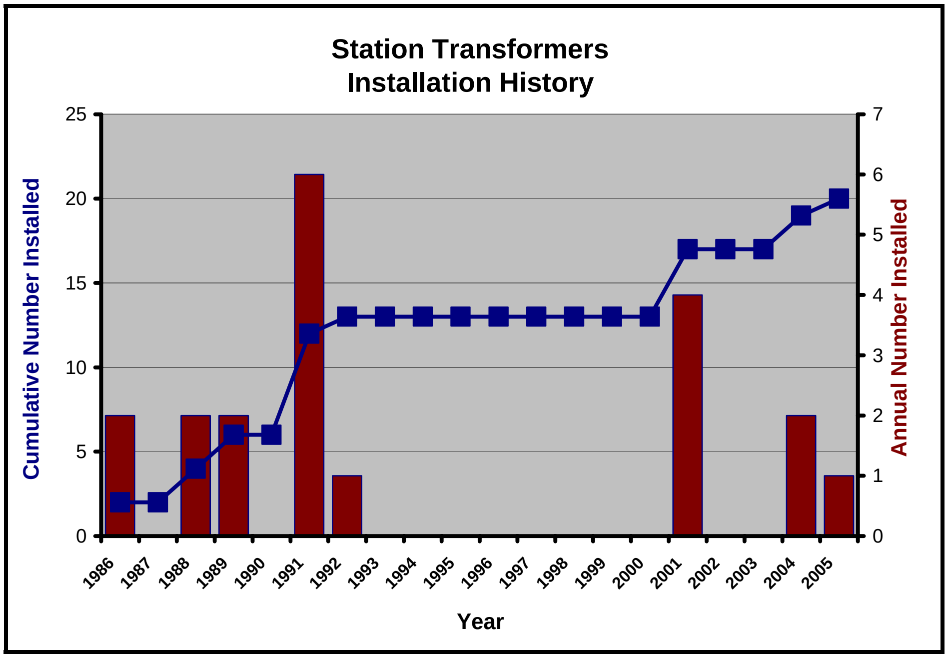

Figure 8. Station transformers installation history.

Asset Degradation

While substation transformers can be employed in either step-up or step-down mode, a majority of the applications in transmission and distribution stations involve step down of the transmission or sub-transmission voltage to distribution voltage levels. Substation transformers vary in capacity and ratings over a broad range.

For a majority of transformers, end of life (EOL) is expected to be defined by the failure of an insulation system and more specifically the failure of pressboard and paper insulation. While the insulating oil can be treated or changed, it is not practical to change the paper and pressboard insulation. The condition and degradation of the insulating oil, however, plays a significant role in aging and deterioration of transformer, as it directly influences the speed of degradation of the paper insulation. The degradation of oil and paper in service in transformers is essentially an oxidation process. The three important factors that impact the rate of oxidation of oil and paper insulation are presence of oxygen, high temperature and moisture.

The paper insulation consists of long cellulose chains. As the paper ages through oxidization, these chains are broken. The tensile strength and ductility of insulting paper are determined by the average length of the cellulose chains. Therefore, as the paper oxidizes the tensile strength and ductility are significantly reduced and the insulating paper becomes brittle. The average length of the cellulose chains can be determined by measurement of the degree of polymerization (DP). As the paper ages the DP value gradually decreases. The lack of mechanical strength of paper insulation can result in failure if the transformer is subjected to mechanical shocks that may be experienced during normal operational situations.

In addition to the general oxidation of the paper, degradation and failure can also result from partial discharges which can be initiated if the level of moisture is allowed to rise in the paper or if there are other minor defects within active areas of the transformer.

The relative levels of carbon dioxide and carbon monoxide dissolved in oil can provide an indication of paper degradation. Detection and measurement of furans in the oil provides a more direct measure of the paper degradation. Furans are a group of chemicals that are created as a bi-product of the oxidation process of the cellulose chains. The occurrence of partial discharge and other electrical and thermal faults in the transformer can be detected and monitored by measurement of hydrocarbon gases in the oil through Dissolved Gas Analysis (DGA).

Oil analysis is such a powerful diagnostic and condition assessment technique that combining it with background information, related to the specification, operating history, loading conditions and system related issues, provides a very effective means of assessing the condition of transformers and identifying units at high risk of failure.

Other condition assessment techniques for substation transformers include Doble (power factor) testing, infrared surveys, partial discharge detection and location using ultrasonics and/or electromagnetic detection and frequency response analysis.

Load tap changers (LTCs) are prone to failure resulting from either mechanical or electrical degradation. Active maintenance is required for tap changers in order to manage these issues. It is normal practice to maintain tap changers either at a fixed time interval or after a number of operations. During operation wear of contacts and build up of oil degradation products, resulting from arcing activity during make and break of contacts, are the primary degradation processes. Maintenance, cleaning and replacement of contacts and any defective components in the mechanism, and changing or reprocessing of oil are the primary maintenance activities that deal with these issues. Oil analysis for tap changers is considered more difficult than oil analysis for transformers due to the generation of gases and general degradation of the oil during arcing under normal LTC operation.

The health indicator parameters for substation transformers usually include:

- Condition of the bushings,
- Condition of transformer tank,
- Condition of gaskets and oil leaks
- Condition of transformer foundations
- Oil test results and
- Transformer age and winding temperature profiles

The anticipated life of transformers is often quoted as being 40 to 50 years. Many transformers in service are now approaching this age but failure rates remain low and there is little evidence that many are at, or near, EOL. There are a number of contributory factors to the long life of transformers. In the 1950s and 1960s transformers were designed and manufactured conservatively such that the thermal and electrical stresses, even at high load, were relatively low compared to modern designs. In addition, the loading of many of these transformers has been relatively light during their working life.

Health Index Formulation and Results

The following charts provide the main condition parameters that were used in the PowerStream asset condition assessment and the weights assigned to each. Details of the Health Index formulation are provided in the tables.

Transformer Inspections:

Transformer Visual Inspection Criteria	Weight
Bushing Condition	3
Main Tank/ Controls	0.5
Conservator	0.5
Oil Leaks	1
Foundation/Grounding	0.5
Radiator/Cooling	0.5
Overall Physical	2

Trans-former Health Index

Transformer Testing:

Weight	Transformer Testing Analysis Criteria
4	DGA Analysis
4	Furan Analysis
4	Winding Doble Test
2	Thermograph
3	Oil Quality Test

Tap Changer Criteria:

Tap Changer Criteria	Weight
Tank Condition	0.5
Gaskets/Seals	0.5
Control & Mechanism	1
Tank Leaks	1
Overall Physical	2

Figure 9. Station transformers Health Index flowchart.

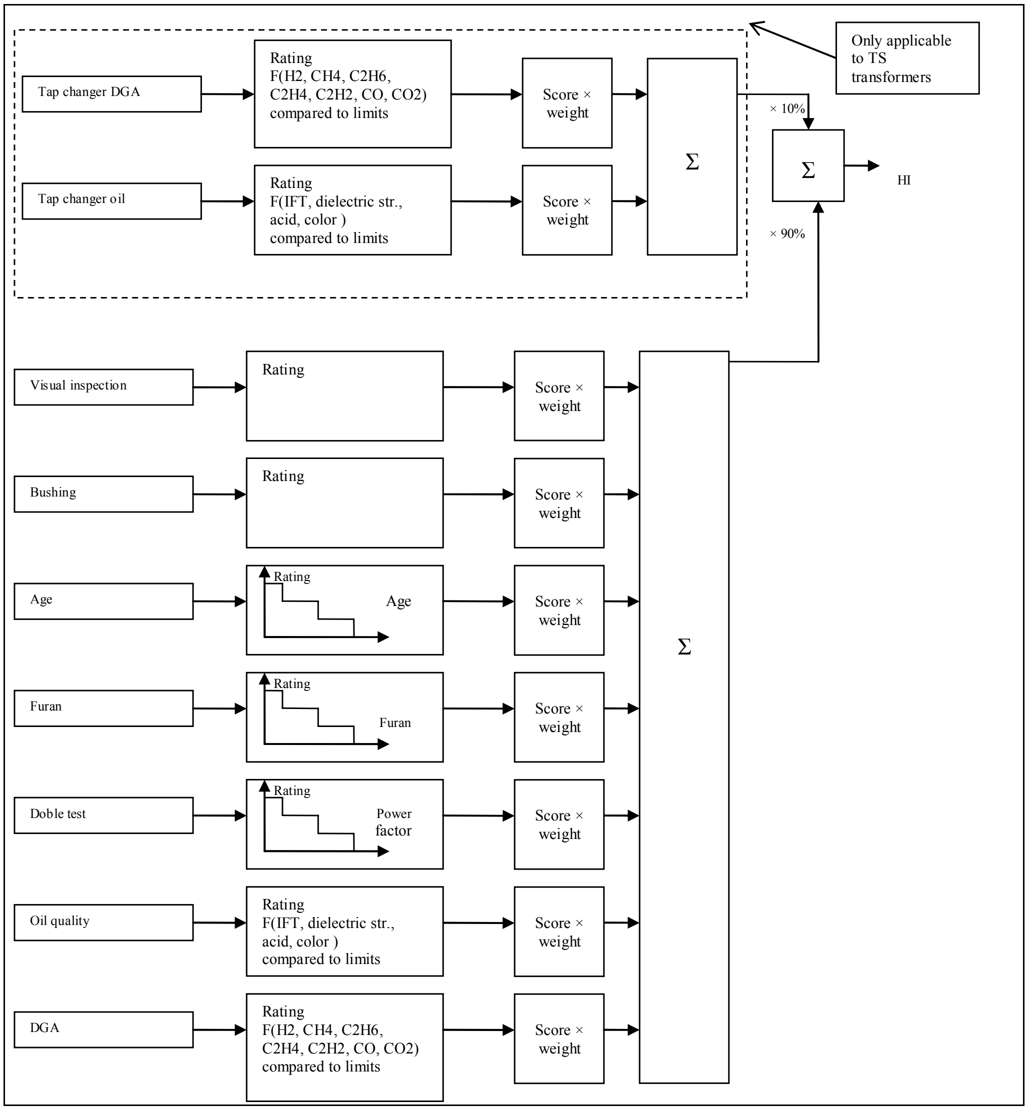

Figure 10. Station transformers Health Index formulation flowchart.

Table 1. Station transformers Health Index parameters and weights

#	Transformers Condition Parameters	Weight
1	Bushing Condition	1
2	Oil Leaks	1
3	Main Tank/Cabinets and Controls	0.5
4	Conservator/Oil Preservation System (Airbag Integrity)	0.5
5	Radiators/Cooling System	0.5
6	Foundation/Support Steel/Ground	0.5
7	Overall Power Transformer	2
8	DGA Oil Analysis*	4
9	Furan Oil Analysis*	4
10	Age	2
11	Winding Doble Test	4
12	Oil Quality Test	3
13	Thermograph (IR)	2
14	Bushing DGA Oil Analysis	2

*In the case of a score of E, overall Health Index is divided by 2

Tap changers are responsible for a high percentage of transformer failures. Therefore, in developing a relevant health index for transformers, it is appropriate to include information specific to tap changers. Table 2 shows the Health Index formulation for tap changers.

Table 2. Station transformers tap changers Health Index parameters and weights

#	Tap Changers Condition Parameters	Weight
1	Tank Condition	0.5
2	Tank Leaks	1
3	Gaskets, Seals and Pressure Relief	0.5
4	LTC Control and Mechanism Cabinet	0.5
5	Control and Mechanisms Cabinet Component and operation	0.5
6	Overall Tap Changer Condition	2
7	DGA,Moisture, Metal Content	4
8	Oil Quality Tests	3

Table 3. Station transformer parameter #1: busing condition

Condition Factor	Factor	Condition Criteria Description
A	4	Bushings are not broken and are free of chips, radial cracks, flashover burns, copper splash and copper wash. Cementing and fasteners are secure.
B	3	Bushings are not broken, however minor chips and cracks are visible. Cementing and fasteners are secure.
C	2	Bushings are not broken, however major chips, and some flashover burns and copper splash are visible. Cementing and fasteners are secure.
D	1	Bushings are broken/damaged or cementing and fasteners are not secure.
E	0	Bushings, cementing or fasteners are broken/damaged beyond repair.

Table 4. Station transformer parameter #2: oil leaks

Condition Factor	Factor	Condition Criteria Description
A	4	No oil leakage or water ingress at any of the bushing-metal interfaces or at gaskets, weld seals, flanges, valve fittings, gauges, monitors.
B	3	Minor oil leaks evident, no moisture ingress likely.
C	2	Clear evidence of oil leaks but rate of loss is not likely to cause any operational or environmental impacts
D	1	Major oil leakage and probable moisture ingress. If left uncorrected it could cause operational and/or environmental problems.
E	0	Oil leaks or moisture ingress have resulted in complete failure or damage/degradation beyond repair.

Table 5. Station transformer parameter #3: transformer main tank/cabinets and control condition

Condition Factor	Factor	Condition Criteria Description
A	4	No rust or corrosion on main tank. No external or internal rust in cabinets – no evidence of condensation, moisture or insect ingress. No rust or corrosion on weld seals, flanges, valve fittings, gauges, monitors. All wiring, terminal blocks, switches, relays, monitoring and control devices are in good condition.
B	3	No rust or corrosion on main tank, some evidence of slight moisture ingress or condensation in cabinets
C	2	Some rust and corrosion on both tank and on cabinets.
D	1	Significant corrosion on main tank and on cabinets. Defective sealing leading to water ingress and insects/rodent damage.
E	0	Corrosion, water ingress or insect/rodent damage or degradation is beyond repair.

Table 6. Station transformer parameter #4: transformer conservator/oil preservation system condition

Condition Factor	Factor	Condition Criteria Description
A	4	No rust or corrosion on body conservator tank. No rust, corrosion on weld seals, flanges, valve fittings, gauges, monitors.
B	3	No rust or corrosion on conservator.
C	2	Some rust and corrosion on conservator.
D	1	Significant rust and corrosion on conservator. Could lead to major oil leakage or water ingress.
E	0	Major oil leakage or water ingress has resulted in damage/degradation beyond repair. Any seal failure on a sealed tank transformer. Note: For transformers employing sealed tanks or air bags, a failure of the seal would be indicated by the presence of air in the tank, which can be detected by measuring oxygen or nitrogen content while conducting gas in oil analysis.

Table 7. Station transformer parameter #5: transformer radiators/cooling system condition

Condition Factor	Factor	Condition Criteria Description
A	4	No rust or corrosion on body of radiators. Fan and pump enclosures are free of rust and corrosion and securely mounted in position, pump bearings are in good condition and fan controls are operating per design.
B	3	Normal signs of wear with respect to the above characteristics.
C	2	One or two of the above characteristics are unacceptable.
D	1	More than two of the above characteristics are unacceptable.
E	0	Fan and pump enclosures damaged/degraded beyond repair.

Table 8. Station transformer parameter #6: transformer foundation/support steel/grounding condition

Condition Factor	Factor	Condition Criteria Description
A	4	Concrete foundation is level and free from cracks and spalling. Support steel and/or anchor bolts are tight and free from corrosion. Ground connections are tight, free of corrosion and made directly to tanks, radiators, cabinets and supports, without any intervening paint or corrosion.
B	3	Normal signs of wear with respect to the above characteristics.
C	2	One of the above characteristics is unacceptable.
D	1	Two or more of the above characteristics are unacceptable.
E	0	Foundation, supports, or grounding damaged/degraded beyond repair.

Table 9. Station transformer parameter #7: overall power transformer condition

Condition Factor	Factor	Condition Criteria Description
A	4	Power transformer externally is clean, and corrosion free. All primary and secondary connections are in good condition. All monitoring, protection and control, pressure relief, gas accumulation and silica gel devices, and auxiliary systems, mounted on the power transformer, are in good condition. No external evidence of overheating or internal overpressure. Appears to be well maintained with service records readily available.
B	3	Normal signs of wear with respect to the above characteristics.
C	2	One or two of the above characteristics are unacceptable.
D	1	More than two of the above characteristics are unacceptable.
E	0	More than two of the above characteristics are unacceptable and cannot be brought into acceptable condition.

Table 10. Station transformer parameter #8: DGA oil analysis

Condition Factor	Factor	Condition Criteria Description
A	4	DGA overall factor is less than 1.2
B	3	DGA overall factor between 1.2 and 1.5
C	2	DGA overall factor is between 1.5 and 2.0
D	1	DGA overall factor is between 2.0 and 3.0
E	0	DGA overall factor is greater than 3.0

Where the DGA overall factor is the weighted average of the following gas scores:

	Scores						
	1	**2**	**3**	**4**	**5**	**6**	**Weight**
H2	<=100	<=200	<=300	<=500	<=700	>700	2
CH4	<=120	<=150	<=200	<=400	<=600	>600	3
C2H6	<=50	<=100	<=150	<=250	<=500	>500	3
C2H4	<=65	<=100	<=150	<=250	<=500	>500	3
C2H2	<=3	<=10	<=50	<=100	<=200	>200	5
CO	<=700	<=800	<=900	<=1100	<=1300	>1300	1
CO2	<=3000	<=3500	<=4000	<=4500	<=5000	>5000	1

Table 11. Station transformer parameter #9: transformer furan analysis

Condition Factor	Factor	Condition Criteria Description
A	4	Less than 1.0 PPM of 2-furaldehyde and no significant change from last test
B	3	Between 1 – 1.5 PPM of 2-furaldehyde and no significant change from last test
C	2	Between 1.5 – 10 PPM of 2-furaldehyde or significant change from last test
D	1	Between 3 - 10 PPM of 2-furaldehyde and significant change from last test
E	0	Greater than 10 PPM of 2-furaldehyde

Table 12. Station transformer parameter #10: age

Condition Factor	Factor	Condition Criteria Description
A	4	Less than 20 years old
B	3	20-40 years old
C	2	40-60 years old
D	1	Greater than 60 years old
E	0	Not Applicable

Table 13. Station transformer parameter #11: winding Doble test

Condition Factor	Factor	Condition Criteria Description
A	4	Values well within acceptable ranges; power factor less than 0.5 %
B	3	N/A
C	2	Values exceed acceptable ranges; power factor between 0.5 – 1%.
D	1	Values considerably exceed acceptable levels; power factor between 1 - 2%
E	0	Values are not acceptable> 2%, immediate attention required; power factor greater than 2%

Table 14. Station transformer parameter #12: oil quality test

Condition Factor	Factor	Condition Criteria Description
A	4	Overall factor is less than 1.2
B	3	Overall factor between 1.2 and 1.5
C	2	Overall factor is between 1.5 and 2.0
D	1	Overall factor is between 2.0 and 3.0
E	0	Overall factor is greater than 3.0

Where the Overall factor is the weighted average of the following gas scores:

	Scores				
	1	**2**	**3**	**4**	**Weight**
*** Moisture PPM (T ^{o}C Corrected)** U $\leq$ 69 kV	<=20	<=30	<=40	>40	4
*** Moisture PPM (T ^{o}C Corrected)** 230 kV $\leq$ U	<=15	<=20	<=25	>25	
*** Dielectric Str. kV 1mm D1816** 230 kV $\leq$ U	>30	>28	>=25	Less than 25	3
*** Dielectric Str. kV 1mm D1816** U $\leq$ 69 kV	>23	>20	>=18	Less than 18	
*** Dielectric Str. kV D877**	>40	>30	>20	Less than 20	
*** IFT dynes/cm** U $\leq$ 69 kV	>20	16-20	13.5-16	Less than 13.5	2
*** IFT dynes/cm** 230 kV $\leq$ U	> 32	25-32	20-25	Less than 20	
Color	Less than 1.5	1.5-2	2-2.5	> 2.5	2
Acid Number	Less than 0.05	0.05-0.1	0.1-0.2	>0.2	1

Table 15. Station transformer parameter #13: transformer thermograph (IR)

Condition Factor	Factor	Condition Criteria Description
A	4	No hot spots are noticeable, no temperature excess over reference point of transformer at normal temperature
B	3	Small hotspots are identified but do not require further investigation, excess of 0-9 degrees over reference point
C	2	Significant hot spots are identified and further investigation is required, excess of 10-20 degrees over reference point
D	1	Serious hot spots are identified that need further investigation/attention as soon as possible, excess of 21-49 degrees over reference point
E	0	Critical hotspots are identified that need immediate attention, excess of more than 50 degrees over reference point

Table 16. Station transformer parameter #14: transformer busing DGA analysis

Condition Factor	Factor	Condition Criteria Description
A	4	Passed test, DGA overall factor less than 3 and Passed PF Test
E	0	Failed test, overall DGA factor greater than 3 or Failed PF Test

Table 17. Station transformer tap changer parameter #1: tank condition

Condition Factor	Factor	Condition Criteria Description
A	4	No external corrosion or rust on the LTC tank, conservator or switch compartments. No rust or corrosion on tank, cover plates, weld seals, flanges, valve fittings, pressure relief diaphragms, qualitrol or other relays and fittings associated with the LTC.
B	3	Normal signs of wear with respect to the above characteristics.
C	2	One of the above characteristics is unacceptable.
D	1	Two or more of the above characteristics are unacceptable.
E	0	More than two unacceptable characteristics that cannot be made acceptable

Table 18. Station transformer tap changer parameter #2: tank leaks

Condition Factor	Factor	Condition Criteria Description
A	4	No external corrosion or rust on the LTC tank, conservator or switch compartments. No rust or corrosion on tank, cover plates, weld seals, flanges, valve fittings, pressure relief diaphragms, qualitrol or other relays and fittings associated with the LTC.
B	3	Normal signs of wear with respect to the above characteristics.
C	2	One of the above characteristics is unacceptable.
D	1	Two or more of the above characteristics are unacceptable.
E	0	More than two unacceptable characteristics that cannot be made acceptable

Table 19. Station transformer tap changer parameter #3: gaskets, seals and pressure relief condition

Condition Factor	Factor	Condition Criteria Description
A	4	No external sign of deterioration of tank gaskets, weld seams or gaskets on valve fittings, pressure relief diaphragms, qualitrol or other relays and fittings associated with the LTC. Weather seal of LTC mechanism cabinet is in good condition. Dynamic seals of drive shaft are in good condition.
B	3	Normal signs of wear with respect to the above characteristics.
C	2	One of the above characteristics is unacceptable.
D	1	Two or more of the above characteristics are unacceptable.
E	0	More than two unacceptable characteristics that cannot be brought into acceptable condition.

Table 20. Station transformer tap changer parameter #4: LTC control and mechanism cabinet

Condition Factor	Factor	Condition Criteria Description
A	4	No external or internal rust in cabinets. No rust, corrosion or paint peeling on cabinets, sealing very effective – no evidence of moisture or insect ingress or condensation. All control devices are in good condition.
B	3	No rust or corrosion, some evidence of slight moisture ingress or condensation in mechanism cabinet or control circuitry.
C	2	Some rust and corrosion on mechanism cabinet or some deterioration of control circuitry, requires corrective maintenance within the next several months.
D	1	Significant corrosion on mechanism cabinet or significant deterioration of control circuitry. Defective sealing leading to water ingress and insects/rodent damage. Requires immediate corrective action.
E	0	Corrosion, water ingress, or insect/rodent damage/degradation that is beyond repair.

Table 21. Station transformer tap changer parameter #5: control and mechanism cabinet component condition

Condition Factor	Factor	Condition Criteria Description
A	4	Wiring, terminal blocks, relays, heaters, motors, contactors and switches all in good condition. LTC operating mechanism, shafts, brakes, gears, bearings, indicators are free from corrosion, abrasion or obstruction and are lubricated. No sign of overheating or deterioration on any electrical or mechanical components..
B	3	A small percentage of the wiring, terminal blocks, relays and switches are in a degraded condition. LTC operating mechanism is in good condition
C	2	About 20% of the wiring, terminal blocks, relays and switches are in a degraded condition. LTC operating mechanism is in fair condition.
D	1	Significant amount of wiring, terminal blocks, relays and switches are in very poor condition. Fuses blow periodically. One or more of the LTC operating mechanism components is in imminent danger of failure. Requires immediate corrective action.
E	0	Components have failed or are damaged/degraded beyond repair.

Table 22. Station transformer tap changer parameter #6: overall tap changer condition

Condition Factor	Factor	Condition Criteria Description
A	4	Tap changer external components, including the mechanism cabinet components, are all in good operating condition, and free from corrosion, deformation, cracks and obstruction. No external evidence of overheating or switch contact failure. Operation counter readings are below the critical range for this type of LTC. Appears to be well maintained with service records readily available.
B	3	Normal signs of wear with respect to the above characteristics.
C	2	One or two of the above characteristics are unacceptable.
D	1	More than two of the above characteristics are unacceptable.
E	0	More than two characteristics that are unacceptable and cannot be brought into acceptable condition.

Table 23. Station transformer tap changer parameter #7: oil analysis (DGA metal content)

Condition Factor	Factor	Condition Criteria Description
A	4	Oil tests passed; DGA overall factor<3 or limited metal content
E	0	Any failed oil test; DGA overall factor>3 or serious metal content

Table 24. Station transformer tap changer parameter #8: oil quality test

Condition Factor	Factor	Condition Criteria Description
A	4	Overall factor is less than 1.2
B	3	Overall factor between 1.2 and 1.5
C	2	Overall factor is between 1.5 and 2.0
D	1	Overall factor is between 2.0 and 3.0
E	0	Overall factor is greater than 3.0

Where the Overall factor is the weighted average of the following gas scores:

	Scores				
	1	2	3	4	Weight
*** Moisture PPM (T °C Corrected)** U ≤ 69 kV	<=20	<=30	<=40	>40	4
*** Moisture PPM (T °C Corrected)** 230 kV ≤U	<=15	<=20	<=25	>25	
*** Dielectric Str. kV 1mm D1816** 230 kV ≤U	>30	>28	>=25	Less than 25	3
*** Dielectric Str. kV 1mm D1816** U ≤ 69 kV	>23	>20	>=18	Less than 18	
*** Dielectric Str. kV D877**	>40	>30	>20	Less than 20	
*** IFT dynes/cm** U ≤ 69 kV	>20	16-20	13.5-16	Less than 13.5	2
*** IFT dynes/cm** 230 kV ≤U	> 32	25-32	20-25	Less than 20	
Color	Less than 1.5	1.5-2	2-2.5	> 2.5	2
Acid Number	Less than 0.05	0.05-0.1	0.1-0.2	>0.2	1

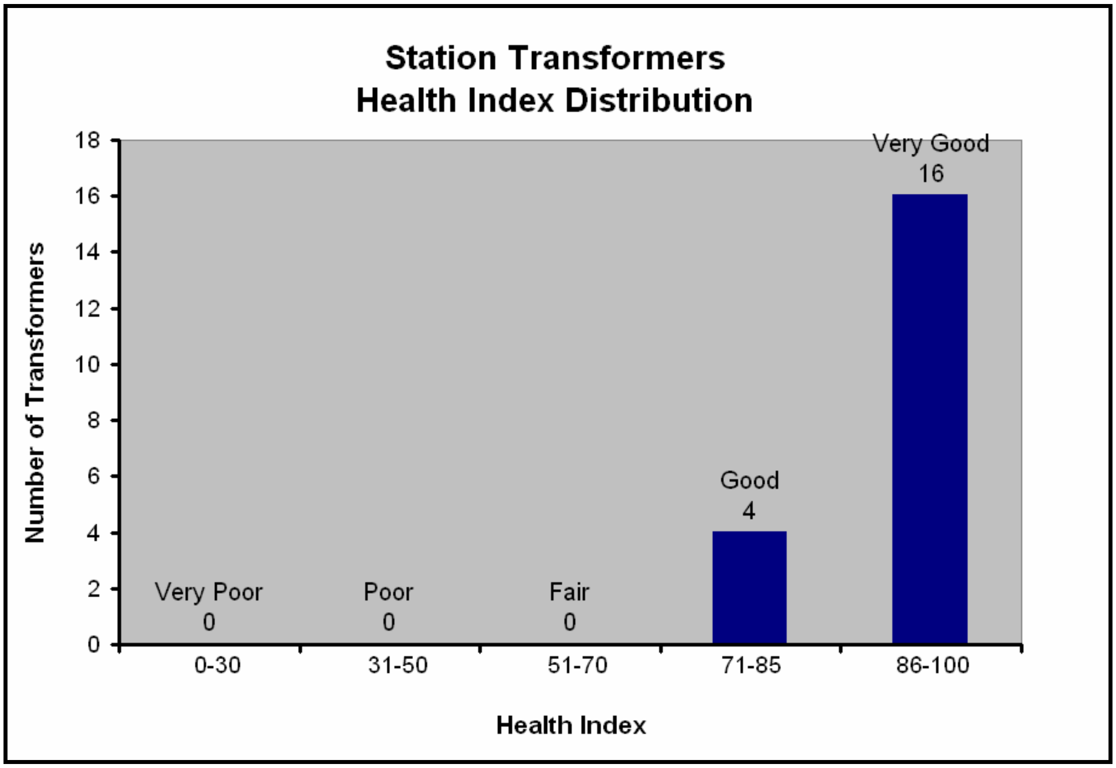

Figure 11. Station transformers Health Index histogram.

Location	Position	Manufacturer	Model	MVA Nameplate	Age	Health Index
Greenwood -Vaughan MTS #1	T1	TTI	ABB	125	17	94
Greenwood -Vaughan MTS #1	T2	TTI	ABB	125	17	80
Greenwood -Vaughan MTS #1 Expansion	T3	ABB	ABB	125	14	93
Greenwood -Vaughan MTS #1 Expansion	T4	ABB	MR	125	1	89
Torstar - Vaughan MTS #2	T1	ABB	ABB	125	14	84
Torstar - Vaughan MTS #2	T2	ABB	ABB	125	14	86
Lorna Jackson - Vaughan MTS #3	T1	ABB	MR	125	5	86
Lorna Jackson - Vaughan MTS #3	T2	ABB	MR	125	5	86
Lazenby MTS1 - Richmond Hill MTS#1	T1	Hyundai	MR	125	14	81
Lazenby MTS1 - Richmond Hill MTS#1	T2	Hyundai	MR	125	14	84
Lazenby MTS1 - Richmond Hill MTS#2	T1	Pauwels	MR	83	4	88
Lazenby MTS1 - Richmond Hill MTS#2	T2	Pauwels	MR	83	4	94
J.V. Fry - Markham MTS#1	T1	Ferranti Packard	FP	83	20	92
J.V. Fry - Markham MTS#1	T2	Ferranti Packard	FP	83	20	92
A.M. Walker - Markham MTS#2	T1	TTI	ASEA	83	18	94
A.M. Walker - Markham MTS#2	T2	TTI	ASEA	83	18	87
D.H. Cockburn - Markham MTS#3	T1	ABB	ABB	83	14	88
D.H. Cockburn - Markham MTS#3	T2	ABB	ABB	83	14	86
D.H. Cockburn - Markham MTS#3 Expansion	T3	Pauwels	MR	83	2	94
D.H. Cockburn - Markham MTS#3 Expansion	T4	Pauwels	MR	83	2	94

Figure 12. Station transformers Health Index results.

As can be seen the lowest Health Index is 80 which is just below Very Good (85), again showing that the overall transformer fleet is in excellent condition.

Failure Probability Curves

The station transformer failure probability (hazard rate) curve is based on a normal curve, with mean life (service life) equal to 50 years.

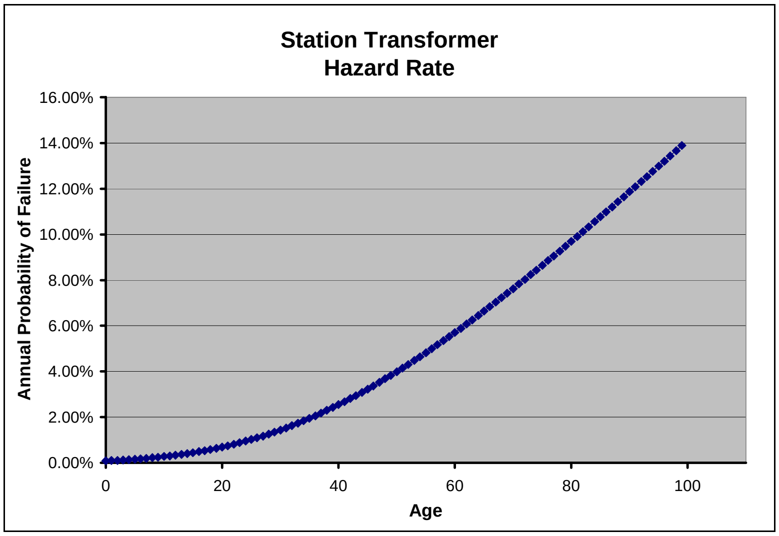

Figure 13. Station transformer hazard rate curve.

The curve fits the failure experience of other utilities with larger populations.

Failure Effects

Failure of a single station transformer is assumed to cause a 5-hour outage. Failure of the second transformer in the station is assumed to cause a 360-hour outage for all customers. Outage costs are based on peak loading.

Risk Matrix

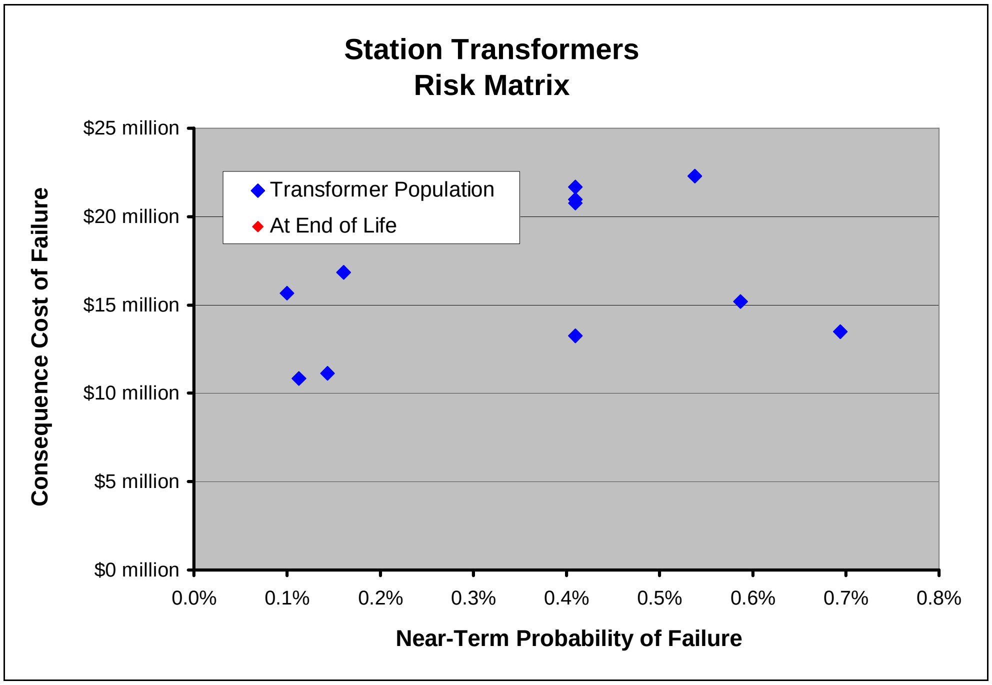

Figure 14. Risk matrix plotting consequence of failure versus failure probability.

Intervention Mode

The intervention mode modeled for station transformers is replacement in-kind. The replacement costs were provided by PowerStream.

Replacement Program Results
The economic model projects the optimal intervention timing for each asset analyzed. The program charts are generated by combining the optimal intervention timings and the associated capital costs.

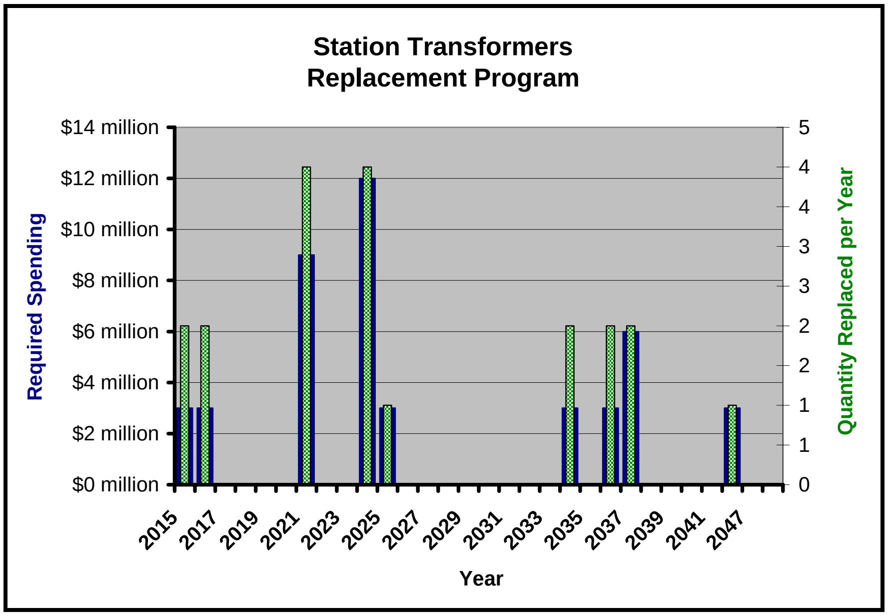

Figure 15. Station transformer 30-year spending program.

Spares Analysis
A spares analysis was performed to determine the benefit of purchasing a spare. The spare decreases the transformer risk cost by reducing the expected outage duration of a transformer failure. The net present value (NPV) of the “No Spares” optimal spending program was compared to the NPV results of the optimal spending programs related to “One 125 MVA Spare” and “One 125 MVA Spare and one 83 MVA Spare” (Figure 17 and Figure 18). Due to the decreased risk cost of having a spare available, some of the transformer investments get shifted further into the future.

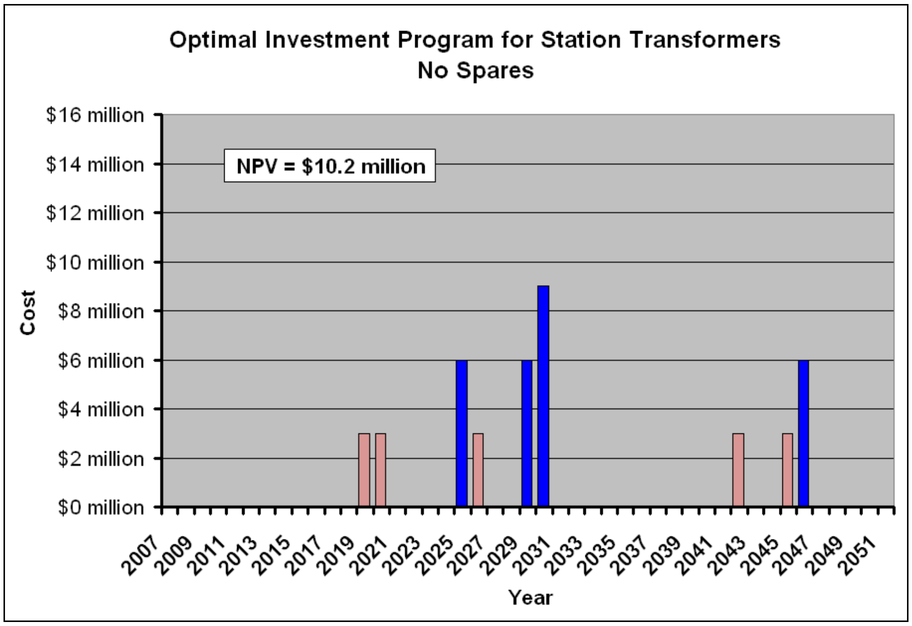

Figure 16. Station transformer optimal investment program (no spares).

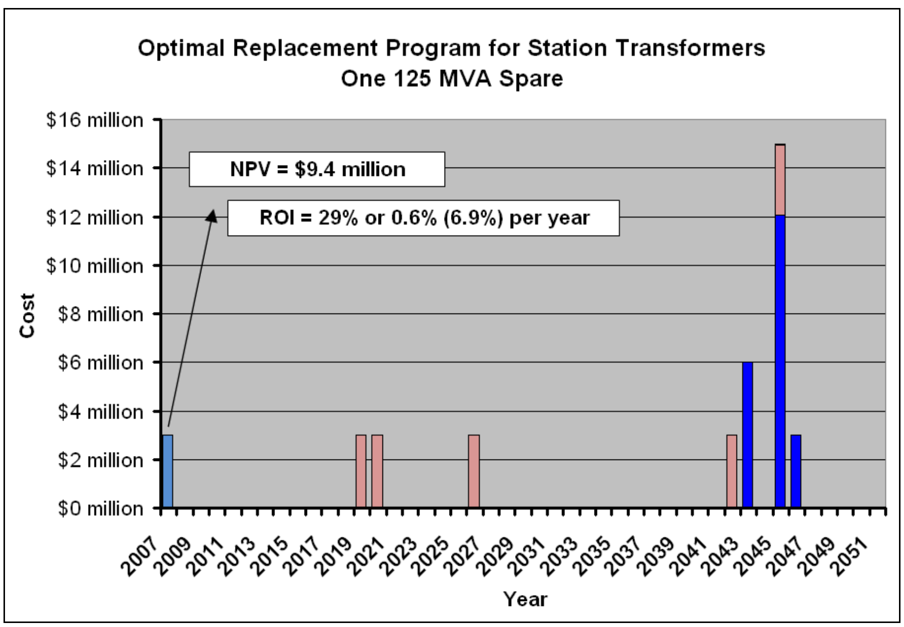

Figure 17. Station transformer optimal replacement program (One 125 MVA spare).

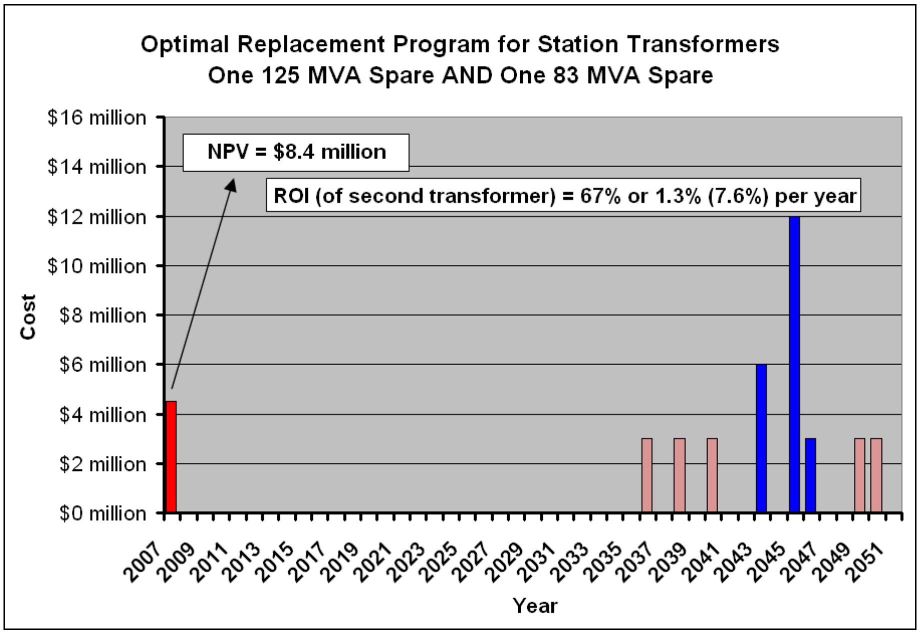

Figure 18. Station transformer optimal replacement program (One 125 MVA spare and one 83 MVA spare).

Scenario	Investment	NPV for Transformer Fleet Lifecycle Optimal Replacement	Total Return on Investment (ROI)	Yearly ROI	Next Year Risk Costs Outage Component	Next Year Risk Costs Other Components
With No Spare Available	$0	$ 10,243,905	-	-	$ 721,274	$ 247,815
First Spare (125 MVA)	$3,000,000	$ 9,378,070	29%	0.56%	$ 477,596	$ 247,815
Second Spare (83 MVA)	$1,500,000	$ 8,365,709	67%	1.30%	$ 272,836	$ 247,815

Figure 19. Spares analysis results.

Investment in spares has the following benefits:

- The overall NPV (Net Present Value) of the transformer fleet, including the cost of buying the spares, is noticeably lower if spares are made available. This is due to the fact that the optimal strategy for transformer replacements is based on the overall life-cycle costs.
- Reduced yearly risk costs. As seen in Figure 19, the outage component for next year will go down approximately threefold with full spare availability.

<u>Conclusions</u>

- Recommendations:
  - The transformers are highly critical to the operation of the system, and although system design is robust, catastrophic risk issues need to be considered.
  - If spares were available, and the catastrophic consequences of the second transformer failure were avoided, all transformers would be operated much longer or closer to real end-of-life.
  - More options in spare analysis can be considered, such as one spare transformer that fits all and sharing spares with others.
- Gaps:
  - None identified.

Circuit Breakers – Asset Class Details and Results

Summary of Asset Class
Circuit breakers are highly complex assets with a moderate price per unit. Types include vacuum, oil, air, and SF6 breakers.

There is limited end-of-life condition data available; health index formulation is based on industry best-practice, and data will be collected in the future.

Data Sources Available
The data sources available for circuit breakers include assumed loading, nameplate, and general demographic information.

Demographics
Number of units: 227
Typical life expectancy (years): 50
Estimated replacement cost: $30,000 - $125,000

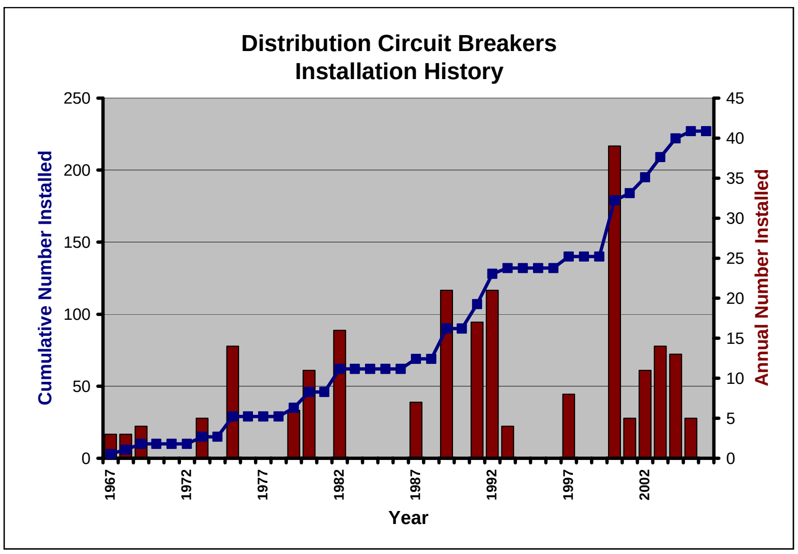

Figure 20. Circuit breaker installation history.

Asset Degradation

The substation breakers are automated switching devices that can make, carry and interrupt electrical currents under normal and abnormal conditions. Circuit breakers are required to operate infrequently, however, when an electrical fault occurs, breakers must operate reliably and with adequate speed to minimize damage. Circuit breakers designs have evolved over the years and many different types are currently in use. Commonly used circuit breaker types include oil circuit breakers, vacuum breakers, magnetic air circuit breakers and SF6 circuit breakers.

Substation breakers have many moving parts that are subject to wear and stress. They frequently "make" and "break" high currents and experience the arcing accompanying these operations. All circuit breakers undergo some contact degradation every time they open to interrupt an arc. Also, arcing produces heat and decomposition products that degrade surrounding insulation materials, nozzles, and interrupter chambers. The mechanical energy needed for the high contact velocities of these assets adds mechanical deterioration to their degradation processes.

The rate and severity of degradation depends on many factors, including insulating and conducting materials, operating environments, and a breaker's specific duties. The International Council on Large Electric Systems' (CIGRE) has identified the following factors that lead to end-of-life for this asset class:

- Decreasing reliability, availability and maintainability
- High maintenance and operating costs
- Changes in operating conditions, rendering the existing asset obsolete;
- Maintenance overhaul requirements; and
- Circuit breaker age.

Outdoor circuit breakers may experience adverse environmental conditions that influence their rate and severity of degradation. For outdoor mounted circuit breakers, the following represent additional degradation factors:

- Corrosion;
- Effects of moisture;
- Bushing/insulator deterioration; and
- Mechanical;

Corrosion and moisture commonly cause degradation of internal insulation, breaker performance mechanisms, and major components like bushings, structural components, and oil seals. Corrosion presents problems for almost all circuit breakers, irrespective of their location or housing material. Rates of corrosion degradation, however, vary depending on exposure to environmental elements. Underside tank corrosion causes problems in many types of breakers, particularly those with steel tanks. Another widespread problem involves corrosion of operating mechanism linkages that result in eventual link seizures. Corrosion also causes damage to metal flanges, bushing hardware and support insulators.

Moisture causes degradation of the insulating system. Outdoor circuit breakers experience moisture ingress through defective seals, gaskets, pressure relief and venting devices. Moisture in the interrupter tank can lead to general degradation of internal components. Also, sometimes free water collects in tank bottoms, creating potential catastrophic failure conditions.

For circuit breakers, mechanical degradation presents greater end-of-life concerns than electrical degradation. Generally, operating mechanisms, bearings, linkages, and drive rods represent components that experience most mechanical degradation problems. Oil and gas leakage also occurs. Contacts, nozzles, and highly stressed components can also experience electrical-related degradation and deterioration. Other defects that arise with aging include:

- Loose primary and grounding connections;
- Oil contamination and/or leakage; and
- Deterioration of concrete foundation affecting stability of breakers.

The diagnostic tests to assess the condition of circuit breakers include:

- Visual inspections
- Travel time tests
- Contact resistance measurements
- Bushing - Doble (Power Factor) Test
- Stored energy tests (Air/Hydraulic/Spring Recharge Time)
- Insulating medium tests

As indicated above, the useful life of circuit breakers can vary significantly depending on the duty cycle and typically lies within a broad range of 25 to 80 years.

Consequences of circuit breaker failure may be significant as they can directly lead to catastrophic failure of the protected equipment, leading to customer interruptions, health and safety consequences and adverse environmental impacts.

Health Index Formulation and Results

The following charts provide the main condition parameters that were used in the PowerStream asset condition assessment and the weights assigned to each. Details of the Health Index formulation are provided in the tables.

The following figure illustrates the HI formulation for circuit breakers.

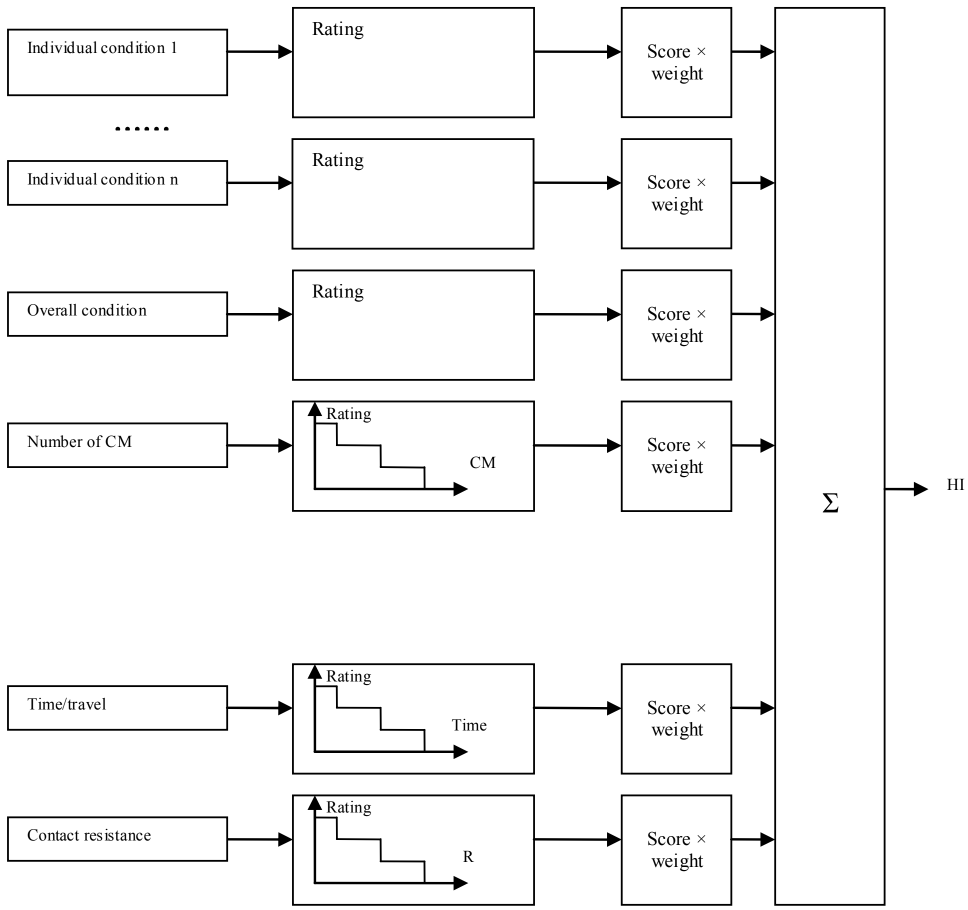

Figure 21. Circuit breaker Health Index formulation flowchart.

Table 25. Circuit breakers Health Index parameters and weights

#	CB Condition Parameters	Weight
1	Bushing/Insulator Condition	3
2	Leaks (OCB only)	3
3	Tank and Control/Mechanism Box	2
4	Control and Mechanism Box Components	2
5	Foundation and Support Steel Grounding	2
6	Overall Condition	4
7	Time/Travel	3
8	Contact Resistance	4
9	Number of Corrective Maintenance	4

Table 26. Circuit breaker parameter #1: bushing/insulator condition

Condition Factor	Factor	Condition Criteria Description
A	4	Bushings/Support Insulators are not broken and are free of chips, radial cracks, flashover burns, copper splash and copper wash. Cementing and fasteners are secure.
B	3	Bushings/Support Insulators are not broken, however there are some minor chips and cracks. No flashover burns or copper splash or copper wash. Cementing and fasteners are secure.
C	2	Bushings/Support Insulators are not broken, however there are some major chips and cracks. Some evidence of flashover burns or copper splash or copper wash. Cementing and fasteners are secure.
D	1	Bushings/Support Insulators are broken/damaged, or cementing or fasteners are not secure.
E	0	Bushings/Support Insulators, cementing or fasteners are broken/damaged beyond repair.

Table 27. Circuit breaker parameter #2: leaks

Condition Factor	Factor	Condition Criteria Description
A	4	No oil leakage or water ingress at any of the bushing-metal interfaces. No oil leakage or water ingress at any of the flanges, manholes, covers, breathers, pipes or gauges. Oil levels are acceptable.
B	3	Minor oil leaks evident, no moisture ingress likely.
C	2	Clear evidence of oil leaks but rate of loss is not likely to cause any operational or environmental impacts
D	1	Major oil leakage and probable moisture ingress at the bushings, or at one other location indicate the immediate need for a major reconditioning or replacement.
E	0	Significant oil leakage and moisture ingress resulting in damage/degradation beyond repair.

Table 28. Circuit breaker parameter #3: tank and control/mechanism box

Condition Factor	Factor	Condition Criteria Description
A	4	No rust or corrosion on main tank. No external or internal rust in cabinets. No rust, corrosion or paint peeling on tanks or cabinets, sealing very effective – no evidence of moisture or insect ingress or condensation.
B	3	No rust or corrosion on main tank, some evidence of slight moisture ingress or condensation in mechanism box.
C	2	Some rust and corrosion on both tank and on mechanism box, requires corrective maintenance within the next several months.
D	1	Significant corrosion on main tank and on mechanism box. Defective sealing leading to water ingress and insects/rodent damage. Requires immediate corrective action.
E	0	Corrosion, water, insect or rodent damage or degradation beyond repair.

Table 29. Circuit breaker parameter #4: control and mechanism components

Condition Factor	Factor	Condition Criteria Description
A	4	Wiring, terminal blocks, relays, contactors and switches all in good condition. Operating mechanism, trip and close coils, relays, auxiliary switches, motors, compressors, springs are all in good condition. No sign of overheating or deterioration. Linkages, drive rods, trip latches are clean, lubricated, free from cracks, distortion, abrasion or obstruction. Mechanical integrity of dampers/dashpots, and oil levels, is acceptable. No visible evidence of poor mechanism settings, looseness, loss of adjustment, excess bearing wear or other out of tolerance operation.
B	3	Normal signs of wear with respect to the above characteristics.
C	2	One or two of the above characteristics are unacceptable.
D	1	More than two of the above characteristics are unacceptable.
E	0	Control and mechanism components are damaged/degraded beyond repair.

Table 30. Circuit breaker parameter #5: foundation and support steel grounding

Condition Factor	Factor	Condition Criteria Description
A	4	Support steel and/or anchor bolts are tight and free from corrosion. Ground connections are direct to tank, cabinets, supports without any intervening paint or corrosion.
B	3	Normal signs of wear with respect to the above characteristics.
C	2	One of the above characteristics is unacceptable.
D	1	Two or more of the above characteristics are unacceptable.
E	0	Supports or grounding are damaged/degraded beyond repair.

Table 31. Circuit breaker parameter #6: overall condition

Condition Factor	Factor	Condition Criteria Description
A	4	Breaker externally is clean, corrosion free. All primary and secondary connections are in good condition. No external evidence of overheating. Number of breaker operations on counter, and run timer readings on auxiliary motors, are below average range for age of breaker. Appears to be well maintained with service records readily available.
B	3	Normal signs of wear with respect to the above characteristics.
C	2	One or two of the above characteristics are unacceptable.
D	1	More than two of the above characteristics are unacceptable.
E	0	The circuit breaker is damaged/degraded beyond repair.

Table 32. Circuit breaker parameter #7: time/travel

Condition Factor	Factor	Condition Criteria Description
A	4	Close travel, wipe, overtravel, rebound and time are all within specified limits. Trip time and velocity are within specified limits. Trip free time is within specified limits. Interpole close and trip contact time spread is within specified limits for the specific application.
B	3	Normal signs of wear with respect to the above characteristics.
C	2	One of the above characteristics is unacceptable.
D	1	Two or more of the above characteristics are unacceptable.
E	0	Two or more of the above characteristics are unacceptable and cannot be brought into acceptable condition.

Table 33. Circuit breaker parameter #8: contact resistance

Condition Factor	Factor	Condition Criteria Description
A	4	Values well within specifications with high margins
B	3	Values close to specification (little or no margin)
C	2	Values do not meet specification (by a small amount)
D	1	Values do not meet specification (by a significant margin)
E	0	Values do not meet specification and cannot be brought into specification condition.

<u>Failure Probability Curves</u>

The circuit breaker failure probability (hazard rate) curves are based on normal curves, with mean life (service life) assumptions as follows:

- OCB = 40 years
- Air, vacuum, and gas-insulated vacuum = 50 years
- SF6 = 35 years

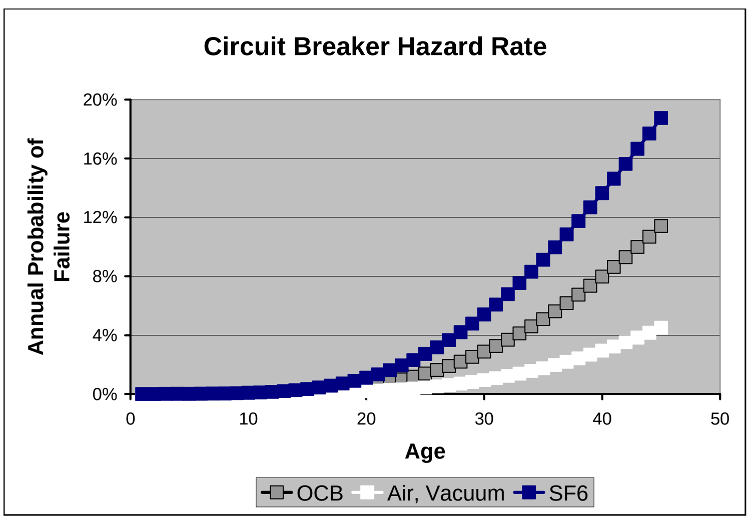

Figure 22. Circuit breaker hazard rate curves.

The curves fit the failure experience of other utilities with larger populations.

Failure Effects

Circuit breakers are assumed to fail with two dominant failure modes: operational failure and catastrophic failure. The relative probability of each failure mode occurring differs for obsolete versus non-obsolete breakers. The failure effects are summarized in Figure 23 and Figure 24 below.

Effects of Distribution Circuit Breaker Failure
Non-Obsolete Breaker

Failure Mode 1		
Relative Probability	50%	
Description	Operational failure	
Effect	Repair required; non-destructive	
Cost		
Direct cost	15%	Percent of replacement cost
Outage cost	2	Hours that breaker is out
Occurrence factor	3	Occurrences over life of breaker

Failure Mode 2		
Relative Probability	50%	
Description	Failure to open; catastrophic	
Effect		
Cost		
Direct cost	115%	Percent of replacement cost
Outage cost	2	Full station is out

Figure 23. Non-obsolete circuit breaker failure effects.

Effects of Distribution Circuit Breaker Failure
Obsolete Breaker

Failure Mode 1		
Relative Probability	40%	
Description	Operational failure	
Effect	Repair required; non-destructive	
Cost		
Direct cost	30%	Percent of replacement cost
Outage cost	2	Hours that breaker is out
Occurrence factor	3	Occurrences over life of breaker

Failure Mode 2		
Relative Probability	60%	
Description	Failure to open; catastrophic	
Effect		
Cost		
Direct cost	130%	Percent of replacement cost
Outage cost	2	Full station is out

Figure 24. Obsolete circuit breaker failure effects.

Risk Matrix

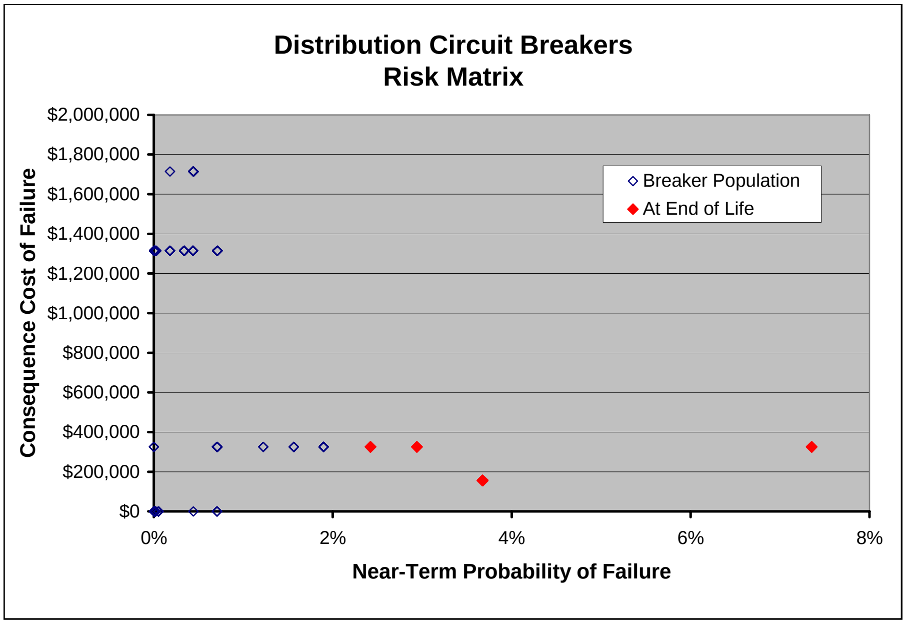

Figure 25. Risk matrix plotting consequence of failure versus failure probability.

Intervention Mode

The intervention mode modeled for circuit breakers is replacement in-kind. The replacement costs vary by circuit breaker type and size. The replacement costs were provided by PowerStream.

Replacement Program Results

The economic model projects the optimal intervention timing for each asset analyzed. The program charts are generated by combining the optimal intervention timings and the associated capital costs.

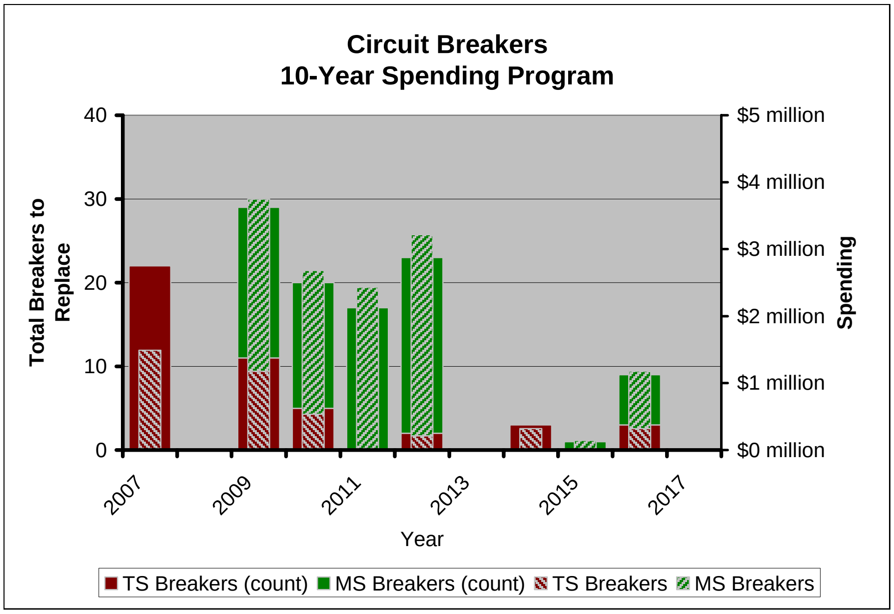

Figure 26. Circuit beaker 10-year spending program.

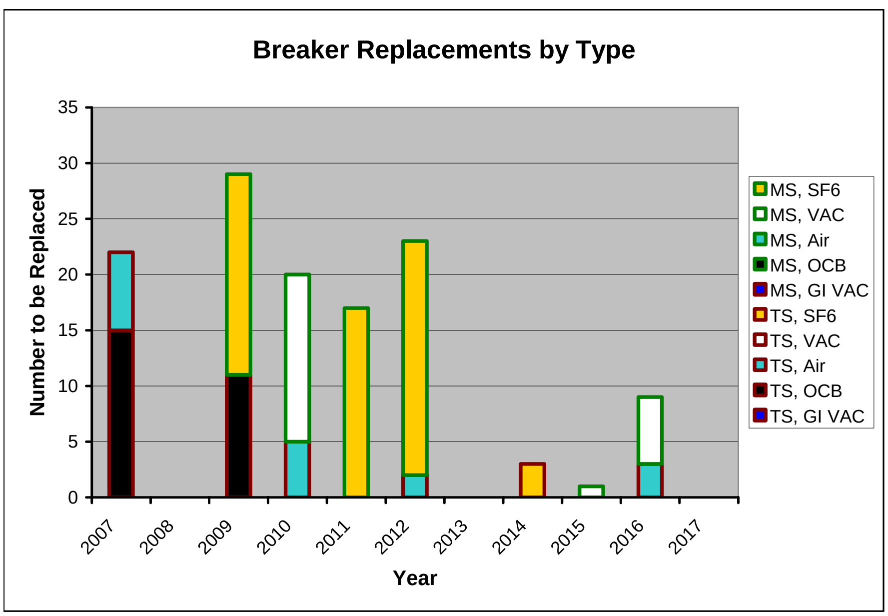

Figure 27. Circuit breaker replacements by type.

<u>Conclusions</u>

- Recommendations:
  - Near-term breaker replacements are warranted.
  - Consider whether "bad-actor" breakers (e.g., ABB) should be sub-classes with their own risk profile.
  - Consider full life-cycle cost, including risk cost, when purchasing new breakers.
  - Consider interventions other than replacement, especially for larger breakers: rehabilitation, purchase of spares.
- Gaps:
  - Capture condition data per Health Index formulation and integrate into the model.

MS Transformers – Asset Class Details and Results

Summary of Asset Class
MS transformers are highly complex assets with a high price per unit.

Many methods are available to assess condition and status; PowerStream employs most of them, which makes analysis of condition a relatively straightforward task.

Distribution transformers serve customers directly, so outage consequences are well-understood. They are a relatively low criticality due to light loading, especially of the oldest units.

Data Sources Available
Comprehensive demographic and condition data was made available. Testing data available included DGA tests and Standard Oil Tests; limited visual condition.

Demographics
Number of units: 22
Typical life expectancy (years): 50
Estimated replacement cost: $300,000 - $450,000

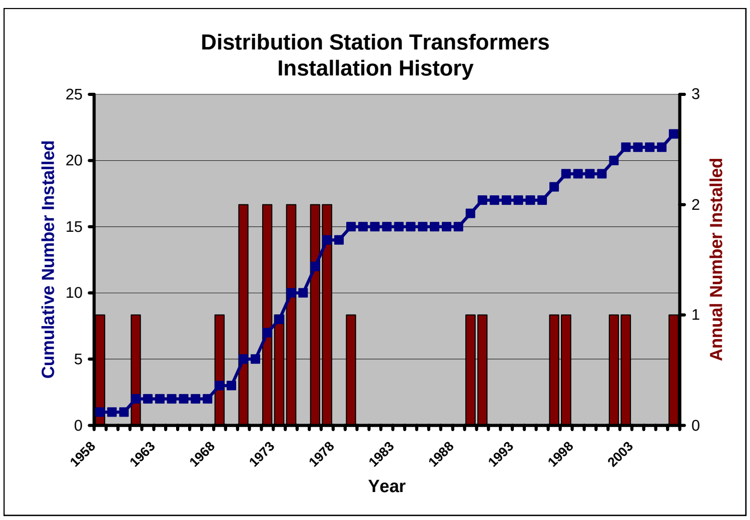

Figure 28. MS transformers installation history.

Asset Degradation

While substation transformers can be employed in either step-up or step-down mode, a majority of the applications in transmission and distribution stations involve step down of the transmission or sub-transmission voltage to distribution voltage levels. Substation transformers vary in capacity and ratings over a broad range.

For a majority of transformers, end of life (EOL) is expected to be defined by the failure of an insulation system and more specifically the failure of pressboard and paper insulation. While the insulating oil can be treated or changed, it is not practical to change the paper and pressboard insulation. The condition and degradation of the insulating oil, however, plays a significant role in aging and deterioration of transformer, as it directly influences the speed of degradation of the paper insulation. The degradation of oil and paper in service in transformers is essentially an oxidation process. The three important factors that impact the rate of oxidation of oil and paper insulation are presence of oxygen, high temperature and moisture.

The paper insulation consists of long cellulose chains. As the paper ages through oxidization, these chains are broken. The tensile strength and ductility of insulting paper are determined by the average length of the cellulose chains. Therefore, as the paper oxidizes the tensile strength and ductility are significantly reduced and the insulating paper becomes brittle. The average length of the cellulose chains can be determined by measurement of the degree of polymerization (DP). As the paper ages the DP value gradually decreases. The lack of mechanical strength of paper insulation can result in failure if the transformer is subjected to mechanical shocks that may be experienced during normal operational situations.

In addition to the general oxidation of the paper, degradation and failure can also result from partial discharges which can be initiated if the level of moisture is allowed to rise in the paper or if there are other minor defects within active areas of the transformer.

The relative levels of carbon dioxide and carbon monoxide dissolved in oil can provide an indication of paper degradation. Detection and measurement of furans in the oil provides a more direct measure of the paper degradation. Furans are a group of chemicals that are created as a bi-product of the oxidation process of the cellulose chains. The occurrence of partial discharge and other electrical and thermal faults in the transformer can be detected and monitored by measurement of hydrocarbon gases in the oil through Dissolved Gas Analysis (DGA).

Oil analysis is such a powerful diagnostic and condition assessment technique that combining it with background information, related to the specification, operating history, loading conditions and system related issues, provides a very effective means of assessing the condition of transformers and identifying units at high risk of failure.

Other condition assessment techniques for substation transformers include Doble (power factor) testing, infrared surveys, partial discharge detection and location using ultrasonics and/or electromagnetic detection and frequency response analysis.

Load tap changers (LTCs) are prone to failure resulting from either mechanical or electrical degradation. Active maintenance is required for tap changers in order to manage these issues. It is normal practice to maintain tap changers either at a fixed time interval or after a number of operations. During operation wear of contacts and build up of oil degradation products, resulting from arcing activity during make and break of contacts, are the primary degradation processes. Maintenance, cleaning and replacement of contacts and any defective components in the mechanism, and changing or reprocessing of oil are the primary maintenance activities that deal with these issues. Oil analysis for tap changers is considered more difficult than oil analysis for transformers due to the generation of gases and general degradation of the oil during arcing under normal LTC operation.

The health indicator parameters for substation transformers usually include:

- Condition of the bushings,
- Condition of transformer tank,
- Condition of gaskets and oil leaks
- Condition of transformer foundations
- Oil test results and
- Transformer age and winding temperature profiles

The anticipated life of transformers is often quoted as being 40 to 50 years. Many transformers in service are now approaching this age but failure rates remain low and there is little evidence that many are at, or near, EOL. There are a number of contributory factors to the long life of transformers. In the 1950s and 1960s transformers were designed and manufactured conservatively such that the thermal and electrical stresses, even at high load, were relatively low compared to modern designs. In addition, the loading of many of these transformers has been relatively light during their working life.

Health Index Formulation and Results

The following figure and charts provide the main condition parameters that were used in the PowerStream asset condition assessment and the weights assigned to each. Details of the Health Index formulation are provided in the tables.

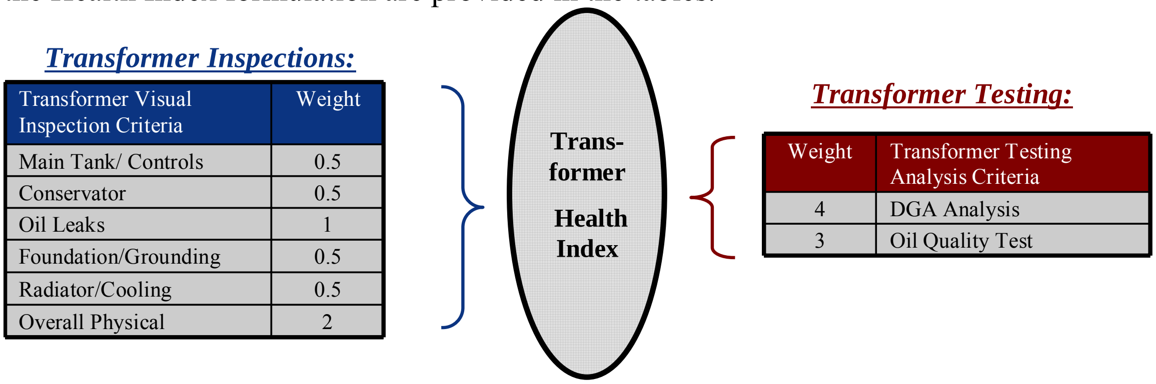

Figure 29. MS transformers Health Index flowchart.

Table 34. Circuit breakers Health Index parameters and weights

#	MS Transformer Condition Parameters	Weight
1	Oil Leaks	1
2	Transformer Main Tank/Cabinets and Control Condition	0.5
3	Transformer Conservator/Oil Preservation System Condition	0.5
4	Transformer Radiators/Cooling System Condition	0.5
5	Transformer Foundation/Support Steel/Grounding Condition	0.5
6	Overall Power Transformer Condition	2
7	DGA Oil Analysis	4
8	Oil Quality Test	3

Table 35. MS transformer parameter #1: oil leaks

Condition Factor	Factor	Condition Criteria Description
A	4	No oil leakage or water ingress at any of the bushing-metal interfaces or at gaskets, weld seals, flanges, valve fittings, gauges, monitors.
B	3	Minor oil leaks evident, no moisture ingress likely.
C	2	Clear evidence of oil leaks but rate of loss is not likely to cause any operational or environmental impacts
D	1	Major oil leakage and probable moisture ingress. If left uncorrected it could cause operational and/or environmental problems.
E	0	Oil leaks or moisture ingress have resulted in complete failure or damage/degradation beyond repair.

Table 36. MS transformer parameter #2: transformer main tank/cabinets and control condition

Condition Factor	Factor	Condition Criteria Description
A	4	No rust or corrosion on main tank. No external or internal rust in cabinets – no evidence of condensation, moisture or insect ingress. No rust or corrosion on weld seals, flanges, valve fittings, gauges, monitors. All wiring, terminal blocks, switches, relays, monitoring and control devices are in good condition.
B	3	No rust or corrosion on main tank, some evidence of slight moisture ingress or condensation in cabinets
C	2	Some rust and corrosion on both tank and on cabinets.
D	1	Significant corrosion on main tank and on cabinets. Defective sealing leading to water ingress and insects/rodent damage.
E	0	Corrosion, water ingress or insect/rodent damage or degradation is beyond repair.

Table 37. MS transformer parameter #3: transformer conservator/oil preservation system condition

Condition Factor	Factor	Condition Criteria Description
A	4	No rust or corrosion on body conservator tank. No rust, corrosion on weld seals, flanges, valve fittings, gauges, monitors.
B	3	No rust or corrosion on conservator.
C	2	Some rust and corrosion on conservator.
D	1	Significant rust and corrosion on conservator. Could lead to major oil leakage or water ingress.
E	0	Major oil leakage or water ingress has resulted in damage/degradation beyond repair. Note: For transformers employing sealed tanks or air bags, a failure of the seal would be indicated by the presence of air in the tank, which can be detected by measuring oxygen or nitrogen content while conducting gas in oil analysis.

Table 38. MS transformer parameter #4: transformer radiators/cooling system condition

Condition Factor	Factor	Condition Criteria Description
A	4	No rust or corrosion on body of radiators. Fan and pump enclosures are free of rust and corrosion and securely mounted in position, pump bearings are in good condition and fan controls are operating per design.
B	3	Normal signs of wear with respect to the above characteristics.
C	2	One or two of the above characteristics are unacceptable.
D	1	More than two of the above characteristics are unacceptable.
E	0	Fan and pump enclosures damaged/degraded beyond repair.

Table 39. MS transformer parameter #5: transformer foundation/support steel/grounding condition

Condition Factor	Factor	Condition Criteria Description
A	4	Concrete foundation is level and free from cracks and spalling. Support steel and/or anchor bolts are tight and free from corrosion. Ground connections are tight, free of corrosion and made directly to tanks, radiators, cabinets and supports, without any intervening paint or corrosion.
B	3	Normal signs of wear with respect to the above characteristics.
C	2	One of the above characteristics is unacceptable.
D	1	Two or more of the above characteristics are unacceptable.
E	0	Foundation, supports, or grounding damaged/degraded beyond repair.

Table 40. MS transformer parameter #6: overall power transformer condition

Condition Factor	Factor	Condition Criteria Description
A	4	Power transformer externally is clean, and corrosion free. All primary and secondary connections are in good condition. All monitoring, protection and control, pressure relief, gas accumulation and silica gel devices, and auxiliary systems, mounted on the power transformer, are in good condition. No external evidence of overheating or internal overpressure. Appears to be well maintained with service records readily available.
B	3	Normal signs of wear with respect to the above characteristics.
C	2	One or two of the above characteristics are unacceptable.
D	1	More than two of the above characteristics are unacceptable.
E	0	More than two of the above characteristics are unacceptable and cannot be brought into acceptable condition.

Table 41. MS transformer parameter #7: DGA oil analysis

Condition Factor	Factor	Condition Criteria Description
A	4	DGA overall factor is less than 1.2
B	3	DGA overall factor between 1.2 and 1.5
C	2	DGA overall factor is between 1.5 and 2.0
D	1	DGA overall factor is between 2.0 and 3.0
E	0	DGA overall factor is greater than 3.0

Where the DGA overall factor is the weighted average of the following gas scores:

	Scores						
	1	**2**	**3**	**4**	**5**	**6**	**Weight**
H2	<=100	<=200	<=300	<=500	<=700	>700	2
CH4	<=120	<=150	<=200	<=400	<=600	>600	3
C2H6	<=50	<=100	<=150	<=250	<=500	>500	3
C2H4	<=65	<=100	<=150	<=250	<=500	>500	3
C2H2	<=3	<=10	<=50	<=100	<=200	>200	5
CO	<=700	<=800	<=900	<=1100	<=1300	>1300	1
CO2	<=3000	<=3500	<=4000	<=4500	<=5000	>5000	1

Table 42. MS transformer parameter #8: oil quality test

Condition Factor	Factor	Condition Criteria Description
A	4	Overall factor is less than 1.2
B	3	Overall factor between 1.2 and 1.5
C	2	Overall factor is between 1.5 and 2.0
D	1	Overall factor is between 2.0 and 3.0
E	0	Overall factor is greater than 3.0

Where the Overall factor is the weighted average of the following gas scores:

	Scores				
	1	**2**	**3**	**4**	**Weight**
*** Moisture PPM (T ^{o}C Corrected)** U ≤ 69 kV	<=20	<=30	<=40	>40	4
*** Moisture PPM (T ^{o}C Corrected)** 230 kV ≤ U	<=15	<=20	<=25	>25	
*** Dielectric Str. kV 1mm D1816** 230 kV ≤ U	>30	>28	>=25	Less than 25	3
*** Dielectric Str. kV 1mm D1816** U ≤ 69 kV	>23	>20	>=18	Less than 18	
*** Dielectric Str. kV D877**	>40	>30	>20	Less than 20	
*** IFT dynes/cm** U ≤ 69 kV	>20	16-20	13.5-16	Less than 13.5	2
*** IFT dynes/cm** 230 kV ≤ U	> 32	25-32	20-25	Less than 20	
Color	Less than 1.5	1.5-2	2-2.5	> 2.5	2
Acid Number	Less than 0.05	0.05-0.1	0.1-0.2	>0.2	1

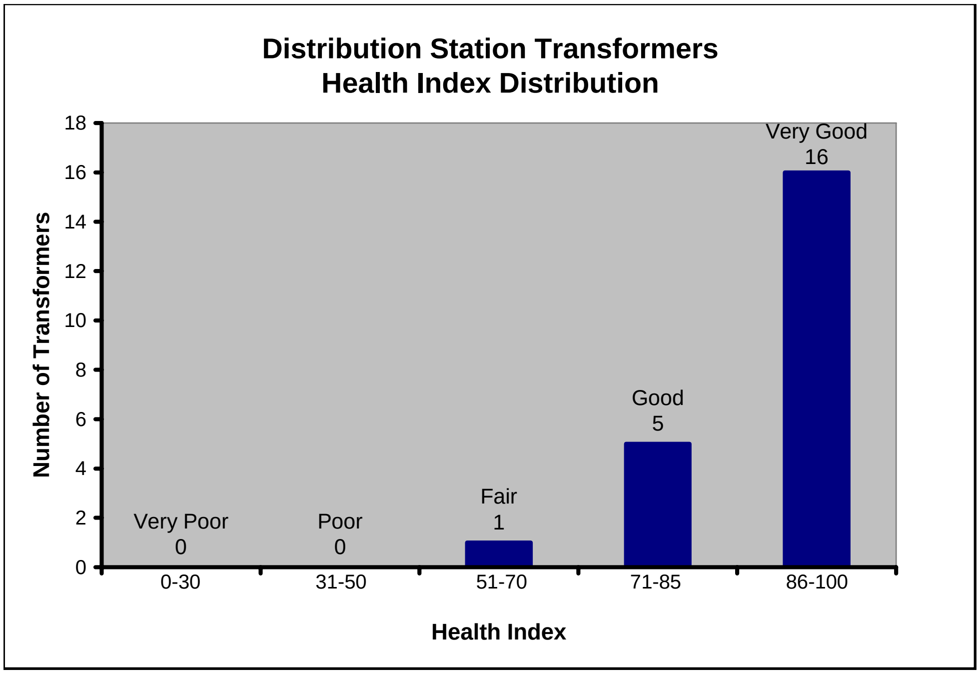

Figure 30. MS transformers Health Index histogram.

Serial Number	Location	Position	Manufacturer	MVA Nameplate	Age	Health Index
259837	Amber MS	T1	West	10	35	94
264055	Amber MS	T2	Moloney	10	35	94
1527013119	Baythorn MS	T1	FPE	7.5	31	91
1535	Baythorn MS	T2	Northern Transformer	7.5	31	94
284243	Morgan MS	T1	Moloney	5	30	56
284242	Morgan MS	T2	Moloney	5	30	86
T51411	John Street MS	T1	Ferranti Packard	10	33	86
72611	John Street MS	T2	Moloney	10	33	78
2591	Elder Mills MS	T1	Ferranti Packard	5	11	92
18780	Rainbow MS	T1		10	37	83
A3S7224	Concord MS	T1	West	15	37	75
292565	King MS	T1	West	5	46	81
HC09198-001	Aurora MS#1	T1	ABB	10	6	100
13185	Aurora MS#1	T2	Ferranti Packard	10	23	94
307486	Aurora MS#2	T1	Ferranti Packard	10	28	72
T-60771	Aurora MS#3	T1	Federal Pioneer	10	18	89
T-60772	Aurora MS#3	T2	Federal Pioneer	10	17	89
51986	Aurora MS#4	T1	Northern Transformer	10	1	100
B3S7297	Aurora MS#4	T2	West	10	34	94
96-1263	Aurora MS#5	T1	Northern Transformer	10	11	100
21718	Aurora MS#5	T2	Northern Transformer	10	5	100
97-1323	Aurora MS#6	T1	Northern Transformer	10	10	100

Figure 31. MS transformers Health Index results.

The Health of the transformer population is generally excellent.
Only 1 transformer is in Fair condition.

Failure Probability Curves
The MS transformer failure probability (hazard rate) curves are based on normal curves, with mean life (service life) equal to 64 years.

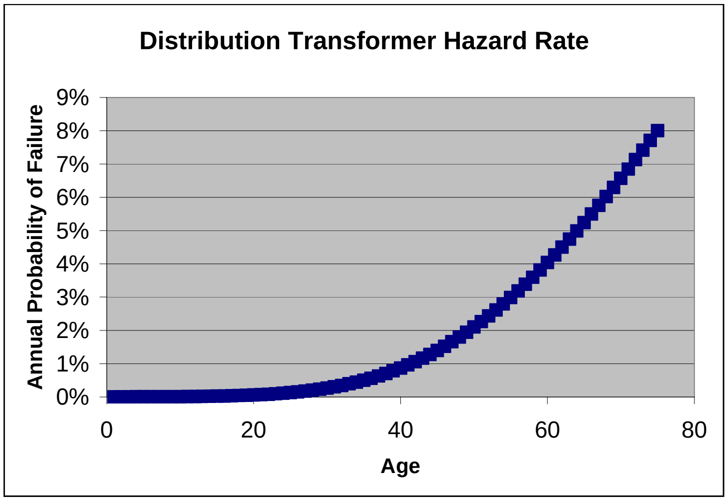

Figure 32. MS transformer hazard rate curve.

The curve fits the failure experience of other utilities with larger populations.

Failure Effects
MS transformer failures are assumed to cause a 5-hour outage. Outage costs are based on peak loading.
Risk Matrix

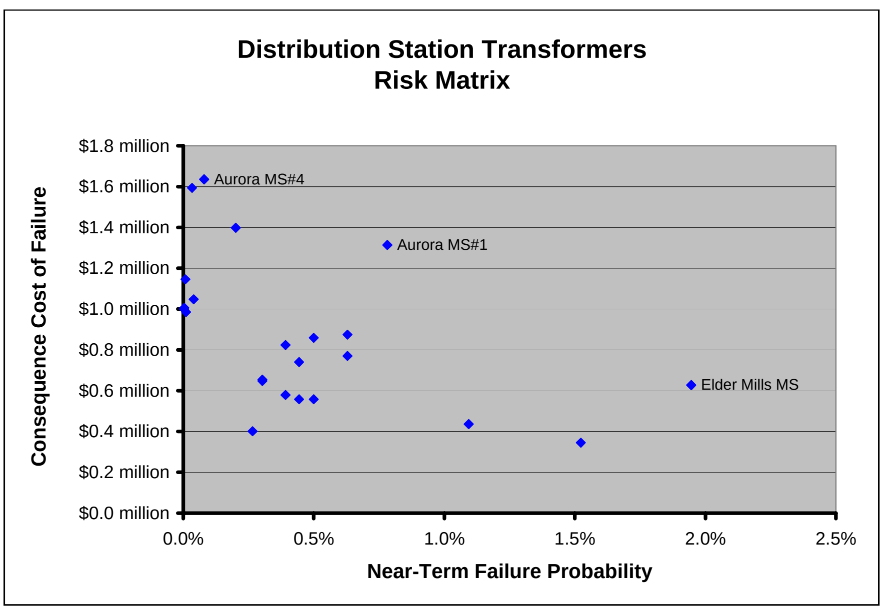

Figure 33. Risk matrix plotting consequence of failure versus failure probability.

Intervention Mode
The intervention mode modeled for MS transformers is replacement in-kind. The replacement costs are summarized in the following table.

Location	Position	Replacement Cost
Amber MS	T1	$400,000
Amber MS	T2	$400,000
Baythorn MS	T1	$350,000
Baythorn MS	T2	$350,000
Morgan MS	T1	$300,000
Morgan MS	T2	$300,000
John Street MS	T1	$400,000
John Street MS	T2	$400,000
Elder Mills MS	T1	$300,000
Rainbow MS	T1	$400,000
Concord MS	T1	$450,000
King MS	T1	$300,000
Aurora MS#1	T1	$400,000
Aurora MS#1	T2	$400,000
Aurora MS#2	T1	$400,000
Aurora MS#3	T1	$400,000
Aurora MS#3	T2	$400,000
Aurora MS#4	T1	$400,000
Aurora MS#4	T2	$400,000
Aurora MS#5	T1	$400,000
Aurora MS#5	T2	$400,000
Aurora MS#6	T1	$400,000

Replacement Program Results
The economic model projects the optimal intervention timing for each asset analyzed. The program charts are generated by combining the optimal intervention timings and the associated capital costs.

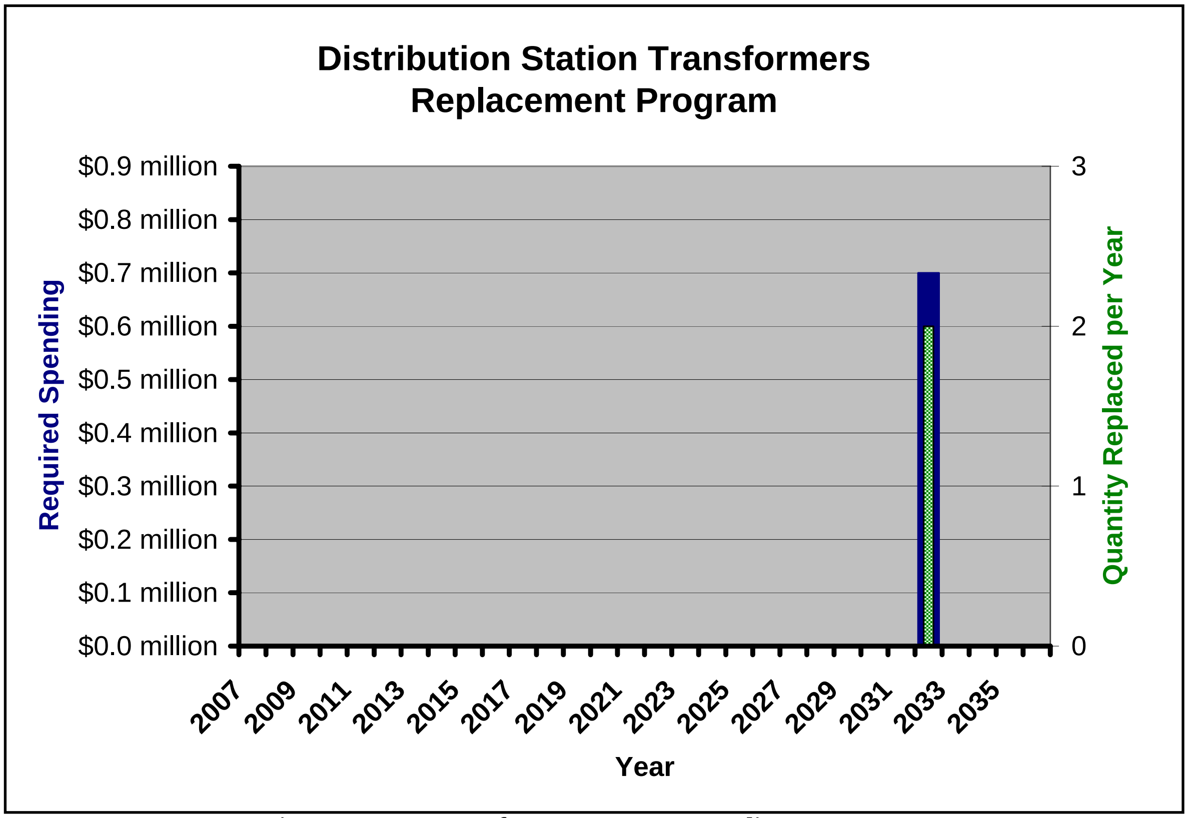

Figure 34. MS transformers 10-year spending program.

<u>Conclusions</u>

- Recommendations:
  - MS transformers are a low-criticality asset; therefore pre-emptive replacement is not generally warranted.
  - Continue to update condition data; degraded transformers may require replacement ahead of schedule.
  - Consider whether the Aurora transformers should be handled differently. They have higher load than many others, and no redundancy.
- Gaps:
  - None identified.

Distribution Primary Cable – Asset Class Details and Results

Summary of Asset Class
Distribution primary cable are a moderately complex asset with a moderate price per meter.

There is no health index formulation calculated for underground cable.

Data Sources Available
Cable installation by drawing number, length, year, cable type, installation method (i.e., conduit, direct bury).

Demographics
Number of units: 3,400 km
Typical life expectancy (years): 35
Estimated replacement cost: $188 - $400/m (cable only), $340 - $660/m (in conduit)

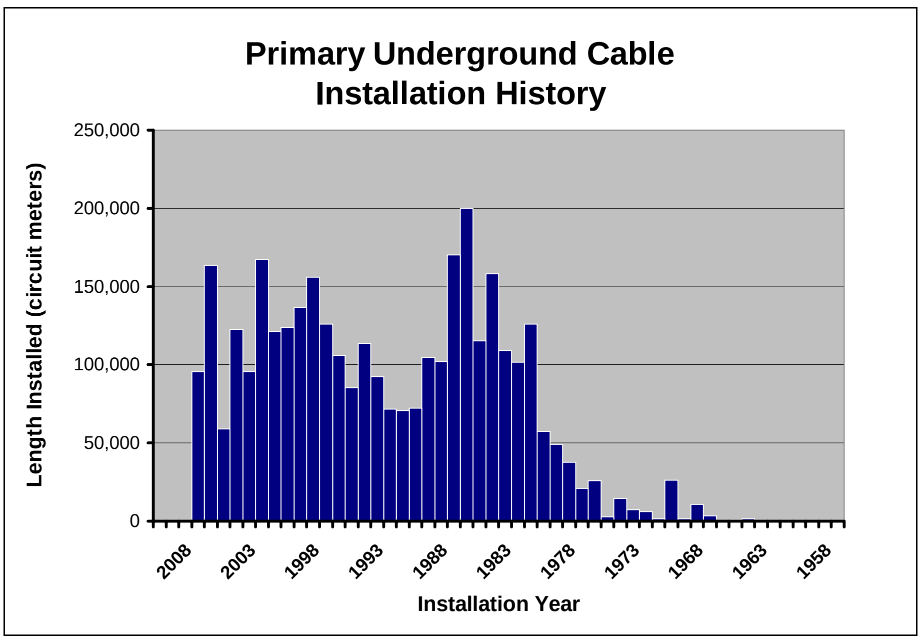

Figure 35. Distribution primary cable installation history.

Health Index Formulation and Results
There is no health index formulation calculated for underground cable.

Failure Probability Curves
The underground cable failure probability (hazard rate) curves are based on failure histories from other utilities with similar cable:

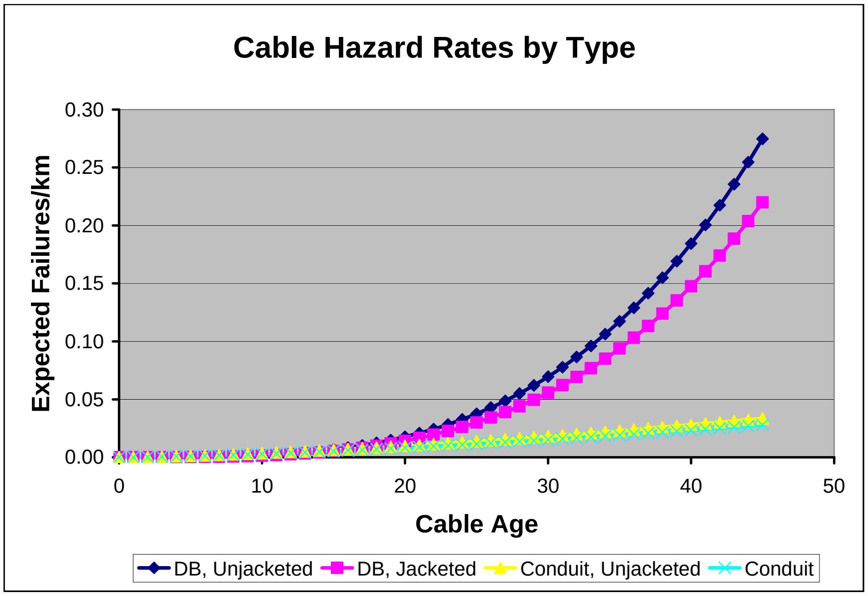

Figure 36. Distribution primary cable hazard rate curve.

Failure Effects
It is assumed that a cable fault on a 1-phase residential looped subdivision will impact 800 kVA (half the loop, 50 amps). For a 3-phase industrial/commercial subdivision, it is assumed that 3,350 kVA will be impacted (half the loop, 70 amps).

Intervention Mode
The intervention modes modeled for underground cable are injection and replacement. Cable injection is assumed to rejuvenate the cable by 20 years. The replacement and injection costs were provided by PowerStream.

Replacement Program Results
The economic model projects the optimal intervention timing for each asset analyzed. The program charts are generated by combining the optimal intervention timings and the associated capital costs.

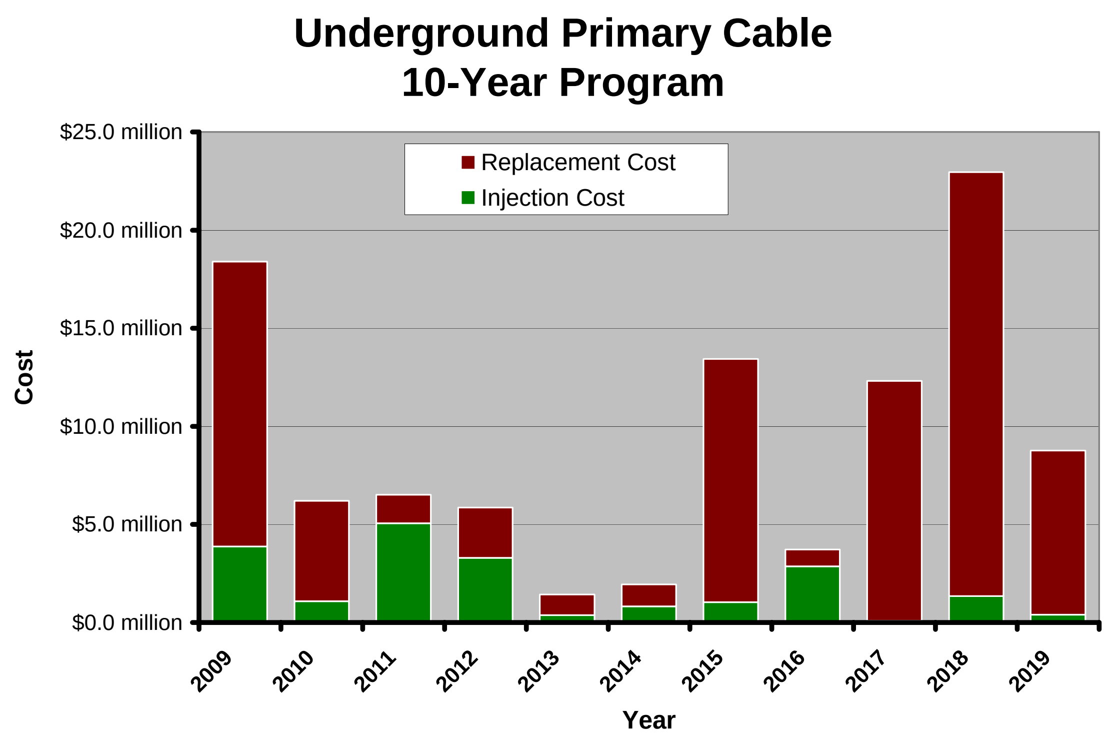

Figure 37. Underground cable 10-year spending program.

<u>Conclusions</u>

- Recommendations:
    - There is a backlog of cable replacements and injections. The backlog will likely require smoothing based on the benefit cost (B/C) ratio of the sections involved and implementation considerations (workload, geography, etc).
    - Cable injection is often a cost-effective intervention if the cable type and vintage is suitable for injection.
    - Assumed industry failure rates should be compared with PowerStream's experience for verification or calibration.
- Gaps:
    - Actual spending programs should be based on more precise information about the loading of the sections, as well as verification of their age, type, and installation method.

Distribution Transformers – Asset Class Details and Results

Summary of Asset Class
MS transformers are moderately complex assets with a relatively low price per unit.

Limited end-of-life condition data available; health index formulation is based on industry best-practice, and data will be collected in the future.

Data Sources Available
Assumed loading, nameplate, and general demographic data.

Demographics
Number of units: 34,299
Typical life expectancy (years): 25-30
Estimated replacement cost: $3,000 - $30,000

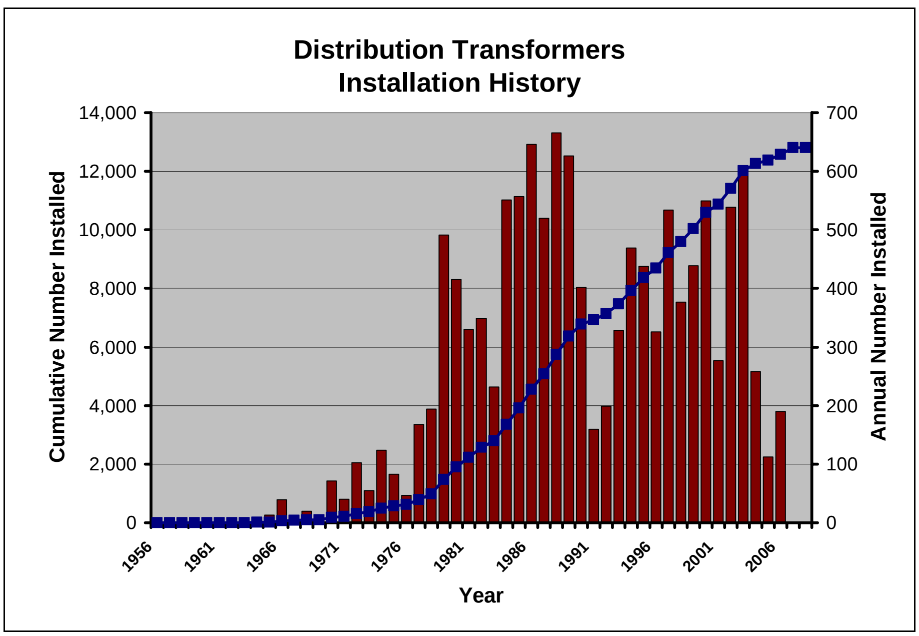

Figure 38. Distribution transformers installation history.

Asset Degradation

Powerstream's distribution transformer asset class consists of all transformers used to step down power from medium voltage to utilization voltage. A majority of these transformers are liquid filled, with mineral insulating oil being the predominant liquid, while the rest are of dry submersible type. All of these designs employ sealed tank construction.

It has been demonstrated that the life of the transformer's internal insulation is related to temperature-rise and duration. Therefore, transformer life is affected by electrical loading profiles and length of service life. Other factors such as mechanical damage, exposure to corrosive salts, and voltage and current surges also have a strong effect. Therefore, a combination of condition, age and load based criteria is commonly used to determine the useful remaining life of distribution transformers.

The impacts of loading profiles, load growth, and ambient temperature on asset condition, loss-of-life, and life expectancy can be assessed using methods outlined in ANSI/IEEE Loading Guides. This also provides an initial baseline for the size of transformer that should be selected for a given number and type of customers to obtain optimal life.

Visual inspections provide considerable information on transformer asset condition. Leaks, cracked bushings, and rusting of tanks can all be established by visual inspections. Transformer oil testing can be employed for distribution transformers to assess the condition of solid and liquid insulation.

Distribution transformers may, sometimes, need to be removed from service as a result of customer load growth. A decision is then required whether to keep the transformer as spare or to scrap it. Many utilities make this decision through a cost benefit analysis, by taking into consideration anticipated remaining life of the transformer, cost of equivalent sized new transformer, labor cost for transformer replacement and rated losses of the older transformer in comparison to the newer designs.

The following factors can be considered in developing the health index for distribution transformers:

- Tank corrosion, condition of paint
- Extent of oil leaks
- Condition of bushings
- Condition of padlocks, warning signs etc
- PCB level
- Transfer operating age and winding temperature profile
- Failure rate

The consequences of distribution transformer failure are mostly reliability impacts and relatively minor. This is why most utilities run their distribution transformers for residential services to failure. However, for larger distribution transformers supplying commercial or industrial customers, where reduction in reliability impacts may be high, transformers may be replaced as they near the end of life.

Health Index Formulation and Results

The following charts provide the main condition parameters that were used in the PowerStream asset condition assessment and the weights assigned to each. Details of the Health Index formulation are provided in the tables.

Table 43. Distribution transformer Health Index parameters and weights

#	Distribution Transformer Condition Parameters	Weight
1	Age	4
2	PCB	1
3	Loading history (weighted average)	*
4	Failure rate	*

* A multiplying factor is adopted for HI adjustment: The initial HI is calculated based on condition criteria # 1 and #2. The final HI result is calculated by multiplying the initial HI with the multiplying factors corresponding to condition criteria #3 and #4. Refer to Table 47 for details on the multiplying factors.

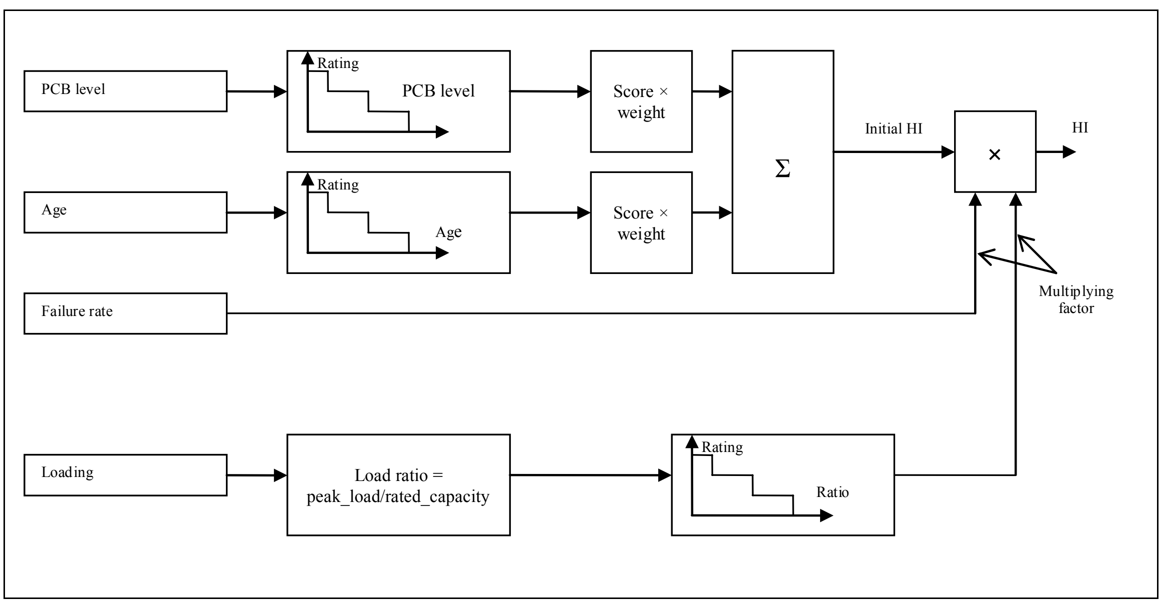

Figure 39. Distribution transformers Health Index flowchart.

Table 44. Distribution transformer parameter #1: age/condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	Less than 20 years old
B	3	20-40 years old
C	2	41-50 years old
D	1	51-60 years old
E	0	>60 years old

Table 45. Distribution transformer parameter #2: PCB level criteria

Condition Factor	Factor	Condition Criteria Description
A	4	PCB < 5 mg/L
B	3	5 <= PCB < 50 mg/L
D	1	50 mg/L <= PCB < 500 mg/L
E	0	PCB >= 500 mg/L

Table 46. Distribution transformer parameter #3: loading criteria

Condition Factor	Multiplying Factor	Condition Criteria Description
A	1	N < 1.26
B	0.9	1.26 <= N < 1.5
C	0.7	1.5 <= N < 1.6
D	0.5	1.6 <= N < 1.67
E	0.3	N >= 1.68

Where N = (Peak Load)/(Rated Capacity)

The loading condition is not assigned a weight in the HI formulation. Instead it is used as a multiplying factor for final HI results.

Table 47. Distribution transformer parameter #4: failure rate

Condition Factor	Multiplying Factor	Condition Criteria Description
A	1	M < 0.05
B	0.9	0.05 <= M < 0.1
C	0.8	0.1 <= M < 0.2
D	0.7	0.2 <= M < 0.4
E	0.6	M >= 0.4

Where M = failure rate x age

The failure rate condition is not assigned a weight in HI formulation. Instead it is used as a multiplying factor for final HI results.

Transformer Size	Voltage	Failure Rate *
300 – 10,000 kVA	0.16 – 15 kV	0.0052
300 – 10,000 kVA	> 15 kV	0.011
> 10,000 kVA		0.0153

* Failure rate is based on the survey data in IEEE Gold book (IEEE Std 493-1997)

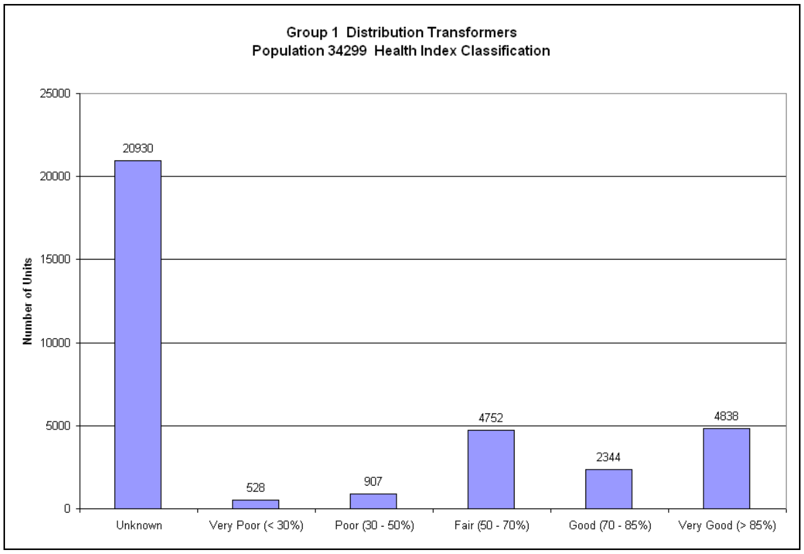

Figure 40. Distribution transformers Health Index histogram.

Failure Probability Curves

The distribution transformer failure probability (hazard rate) curve is based on a Weibull curve, which is calibrated to match the historic failures experienced by PowerStream.

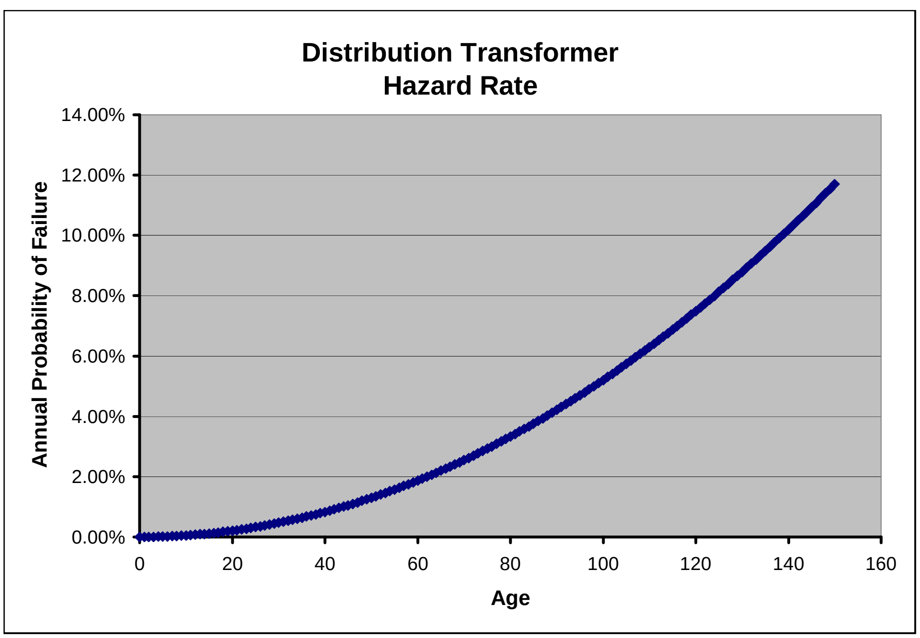

Figure 41. Distribution transformer hazard rate curve.

Failure Effects

The dominant failure mode assessed for distribution transformers is catastrophic failure requiring replacement. The failure effects by type and size are summarized in Figure 42 below.

Type	Phases	Size	Estimated # of Customers without Supply due to Loss of Equipment	Loss of Peak Load (kW)	Outage Duration (hours)	Unsupplied Energy (kWh)	Consequence Cost due to Unsupplied Peak Demand	Consequence Cost due to Unsupplied Energy	Consequence Cost
Overhead	1	25	5	20	3	60	$400	$600	$1,000
Overhead	1	50	8	32	3	96	$640	$960	$1,600
Overhead	1	100	16	64	3	192	$1,280	$1,920	$3,200
Overhead	1	167	30	120	3	360	$2,400	$3,600	$6,000
Overhead	3	50	4	100	4	400	$2,000	$4,000	$6,000
Overhead	3	100	7	170	4	680	$3,400	$6,800	$10,200
Overhead	3	167	10	300	4	1,200	$6,000	$12,000	$18,000
Overhead	3	250	7	444	4	1,776	$8,880	$17,760	$26,640
Overhead	3	333	10	575	4	2,300	$11,500	$23,000	$34,500
Overhead	3	750	11	635	4	2,540	$12,700	$25,400	$38,100
Vault	3	50	4	100	4	400	$2,000	$4,000	$6,000
Vault	3	100	7	170	4	680	$3,400	$6,800	$10,200
Vault	3	167	10	300	4	1,200	$6,000	$12,000	$18,000
Vault	3	250	7	444	4	1,776	$8,880	$17,760	$26,640
Vault	3	333	10	575	4	2,300	$11,500	$23,000	$34,500
Vault	3	750	11	635	4	2,540	$12,700	$25,400	$38,100
Padmount	1	50	8	32	3	96	$640	$960	$1,600
Padmount	1	100	16	64	3	192	$1,280	$1,920	$3,200
Padmount	1	167	30	120	3	360	$2,400	$3,600	$6,000
Padmount	3	150	4	100	4	400	$2,000	$4,000	$6,000
Padmount	3	300	7	170	4	680	$3,400	$6,800	$10,200
Padmount	3	500	10	300	4	1,200	$6,000	$12,000	$18,000

Figure 42. Distribution transformers failure effects.

Intervention Mode

The intervention mode modeled for distribution transformers is replacement in-kind. The replacement costs vary by type and size. The replacement costs were provided by PowerStream, and are summarized in Figure 43 below.

Description	PowerStream Stock Code	Secondary Voltage	Have Spare	Type	Phases	Size	LOOKUP	Replacement Cost
1-phase 25 kVA	3162025	120/240	Y	Overhead	1	25	Overhead-1-25	$3,426
1-phase 50 kVA	3162050	120/240	Y	Overhead	1	50	Overhead-1-50	$4,226
1-phase 100 kVA	3162100	120/240	Y	Overhead	1	100	Overhead-1-100	$5,526
1-phase 167 kVA	3162167	120/240	Y	Overhead	1	167	Overhead-1-167	$7,126
3-Phase 50 kVA	3163050	600/347	Y	Overhead	3	50	Overhead-3-50	$5,404
3-Phase 100 kVA	3163100	600/347	Y	Overhead	3	100	Overhead-3-100	$6,604
3-Phase 167kVA	3163167	600/347	Y	Overhead	3	167	Overhead-3-167	$8,204
1-Phase 50 kVA	3172050	120/208	Y	Vault	1	50	Vault-1-50	$6,990
1-Phase 100 kVA	3172100	120/208	Y	Vault	1	100	Vault-1-100	$8,716
1-Phase 167kVA	3172167	120/208	Y	Vault	1	167	Vault-1-167	$10,841
3-Phase 100 kVA	3173100	600/347	Y	Vault	3	100	Vault-3-100	$9,115
3-Phase 167kVA	3173167	600/347	Y	Vault	3	167	Vault-3-167	$11,240
3-Phase 250 kVA	3173250	600/347	Y	Vault	3	250	Vault-3-250	$17,614
1-phase 50 kVA	4162050	120/240	Y	Padmount	1	50	Padmount-1-50	$7,298
1-phase 100 kVA	4162100	120/240	Y	Padmount	1	100	Padmount-1-100	$9,278
1-phase 167 kVA	4162167	120/240	Y	Padmount	1	167	Padmount-1-167	$9,542
3-Phase 150 kVA	7302150	120/208	Y	Padmount	3	150	Padmount-3-150	$21,144
3-Phase 300 kVA	7302300	120/208	Y	Padmount	3	300	Padmount-3-300	$25,104
3-Phase 500 kVA	7302500	120/208	Y	Padmount	3	500	Padmount-3-500	$28,536
3-Phase 150 kVA	7306150	600/347	Y	Padmount	3	150	Padmount-3-150	$21,804
3-Phase 300 kVA	7306300	600/347	Y	Padmount	3	300	Padmount-3-300	$25,764
3-Phase 500 kVA	7306500	600/347	Y	Padmount	3	500	Padmount-3-500	$29,724

Figure 43. Distribution transformers replacement costs.

Replacement Program Results

The economic model projects the optimal intervention timing for each asset analyzed. The program charts are generated by combining the optimal intervention timings and the associated capital costs. The raw replacement program chart (Figure 44) shows results for transformers with complete demographic data (i.e., type and size).

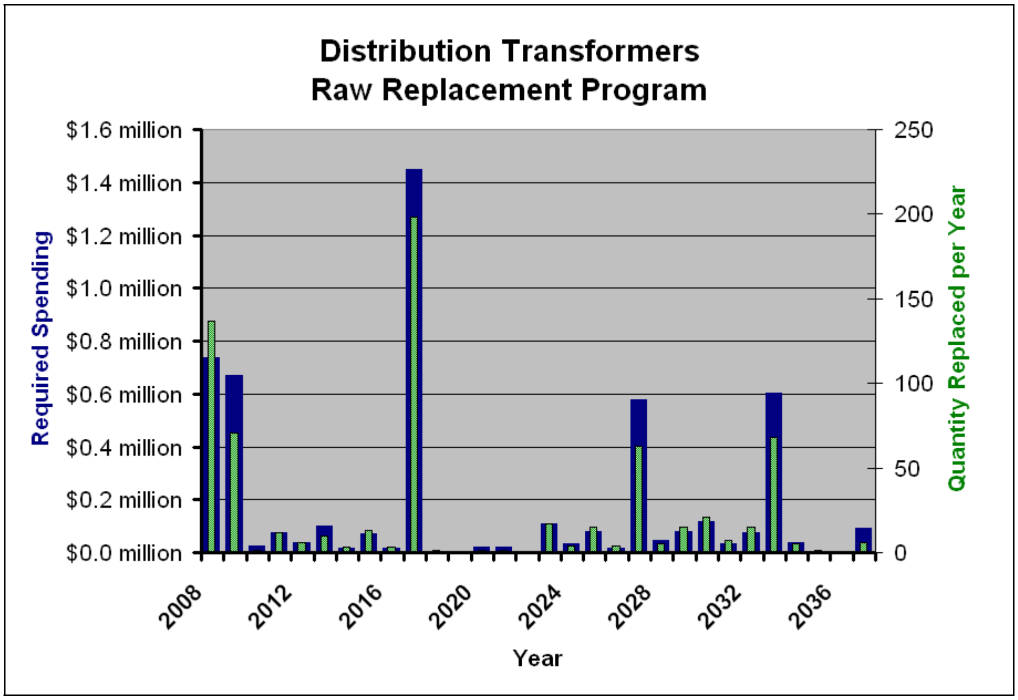

Figure 44. Distribution transformers raw replacement program.

The projected failures (Figure 45) account for system-wide annual failures. The replacement risk is an estimate of the reactive replacement spending associated with the projected failures. The planned and reactive spending programs are extrapolated to account for missing demographic data.

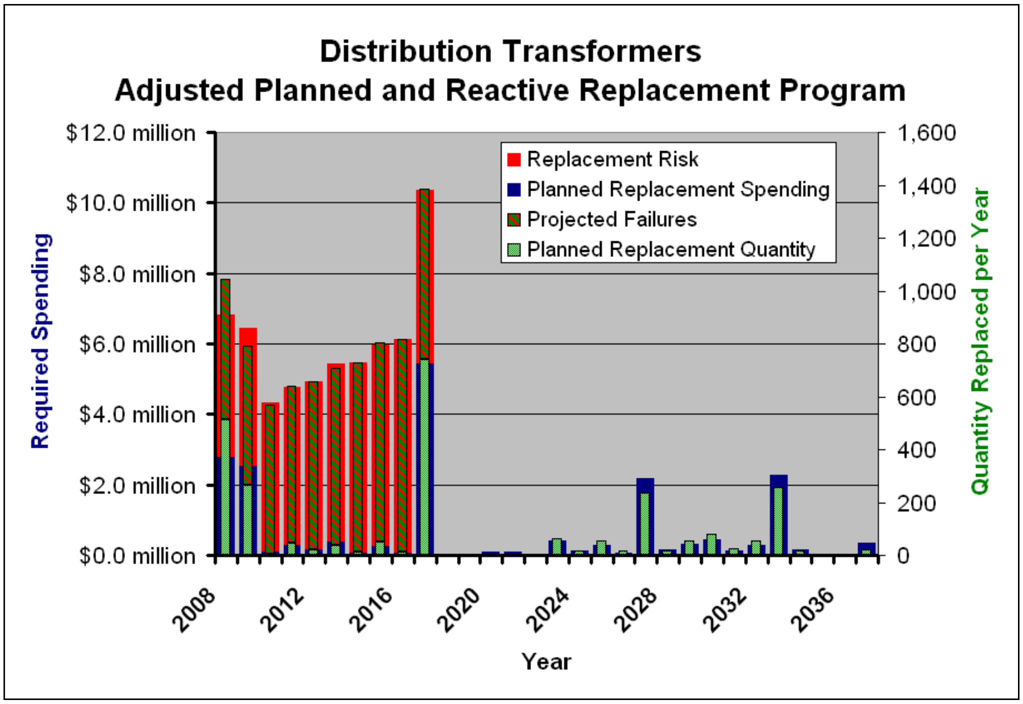

Figure 45. Distribution transformers extrapolated program.

<u>Conclusions</u>

- Recommendations:
  - Near-term transformer replacements are warranted.
  - Continue collecting nameplate data and update the model.
  - Continue capturing condition data per health index formulation and update the model. This should be an ongoing process of updating and re-running to generate annual budgets.
  - Consider capturing transformer condition and age at failure to support customized failure probability curves and health index correlations.
  - Consider full life-cycle cost, including risk cost, when purchasing new transformers.
- Gaps:
  - Limited demographic and condition data available.

Distribution Switchgear – Asset Class Details and Results

Summary of Asset Class
Distribution switchgear are moderately complex assets with a moderate price per unit.

Limited end-of-life condition data available; health index formulation is based on industry best-practice, and data will be collected in the future.

Data Sources Available
Assumed loading, nameplate, and general demographic data.

Demographics
Number of units: 1,170 (air), 293 (oil)
Typical life expectancy (years): 75
Estimated replacement cost: $25,000 - $100,000

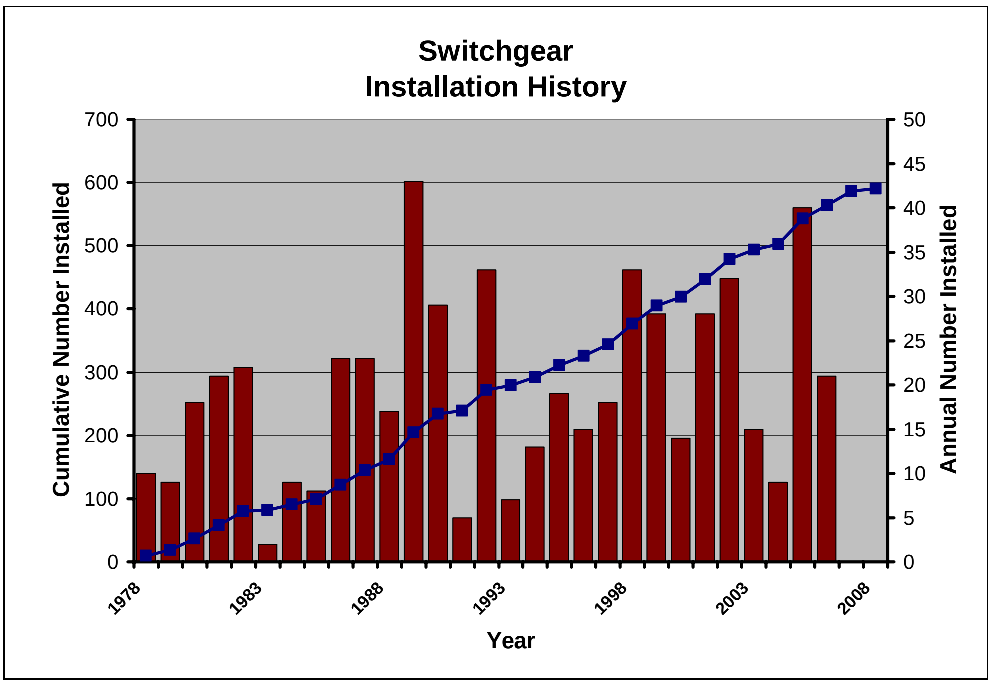

Figure 46. Distribution switchgear installation history.

Asset Degradation

This asset group covers the metal clad switchgear commonly employed at substations. Metalclad switchgear typically consists of an assembly of retractable/racked switching, metering and protection and control devices that are totally enclosed in a metal envelope. The switchgear comes in standard MV operating voltage ratings and includes busbar, circuit breakers, disconnect switches, fuses, protection and auxiliary relays, instrument switchgear, metering devices, etc. The gear is modular (i.e., each breaker is enclosed in its own metal envelope (cell)). The gear is also compartmentalized with separate compartments for breakers, control, incoming/outgoing cables or bus duct, and busbars associated with each cell.

The metalclad switchgear is typically compartmentalized, with separate cells for the following functions:

- Bus-bar Compartment
- Switching Compartment
- Cable Compartment
- Control Compartment

All compartments are isolated from each other by metal partitions to prevent inadvertent contact with live parts, particularly during maintenance. In the breaker compartment, a moveable shutter shields the main contacts when the breaker is withdrawn, and is retracted when the breaker is being racked in to allow breaker connection to the main contacts. Final racking in of the breaker can only be done from outside the switchgear to ensure personnel safety. Also for safety reasons, the breaker door can only be opened after the breaker is tripped.

While the switchgear degradation is a function of a number of different factors, such as condition of mechanical mechanisms and interlocks, degradation of solid insulation and general degradation/corrosion, in most cases end-of-life is related to non-conditional issues. The important issues tend to be capability, obsolescence or specific/generic defects.

If the fault level on the system increases to exceed the rated interrupting value of the switchgear, the switchgear must be upgraded to meet the new requirements or the system reconfigured to reduce the fault levels. For much of the old vintage switchgear currently in use the original manufacturers no longer exist. It is therefore becoming increasingly difficult to obtain spare or replacement parts. In some cases alternative sources of replacement parts can be located, however, difficulties and failures have occurred where these have not met the original manufacturer’s specifications.

In the absence of specifically identified problems, the common industry practice for distribution switchgear is running it to end of life, just short of failure. To extend the life of these assets and to minimize in-service failures, a number of intervention strategies are employed on a regular basis: e.g. inspection with thermographic analysis and cleaning with CO_2 for air insulated pad-mounted switchgear. If problems or defects are identified during inspection, often the affected component can be replaced or repaired without a total replacement of the switchgear.

The switchgear health and condition can be indicated by the following parameters:

- Equipment age
- Presence of hotspots (indicated by thermal scan)
- Condition mechanical interlocks
- Condition of controls and relays
- Condition of bus insulation (indicated by meggar tests)
- Failure rate

The life expectancy for medium voltage distribution switchgear is 50 to 70 years. Failure consequences are serious and include customer interruptions over extended length of time, loss of revenue and employee safety.

Health Index Formulation and Results

The following charts provide the main condition parameters that were used in the PowerStream asset condition assessment and the weights assigned to each. Details of the Health Index formulation are provided in the tables.

Table 48. Distribution switchgear Health Index parameters and weights

#	Distribution Switchgear Condition Parameters	Air Type Weight	Oil Type Weight
1	Age	2	5
2	IR record	2	2
3	Field inspection	5	5
4	Failure rate	*	*

* A multiplying factor is adopted for HI adjustment: The initial HI is calculated based on condition criteria # 1 to #3. The final HI result is calculated by multiplying the initial HI with the multiplying factors corresponding to condition criterion #4.

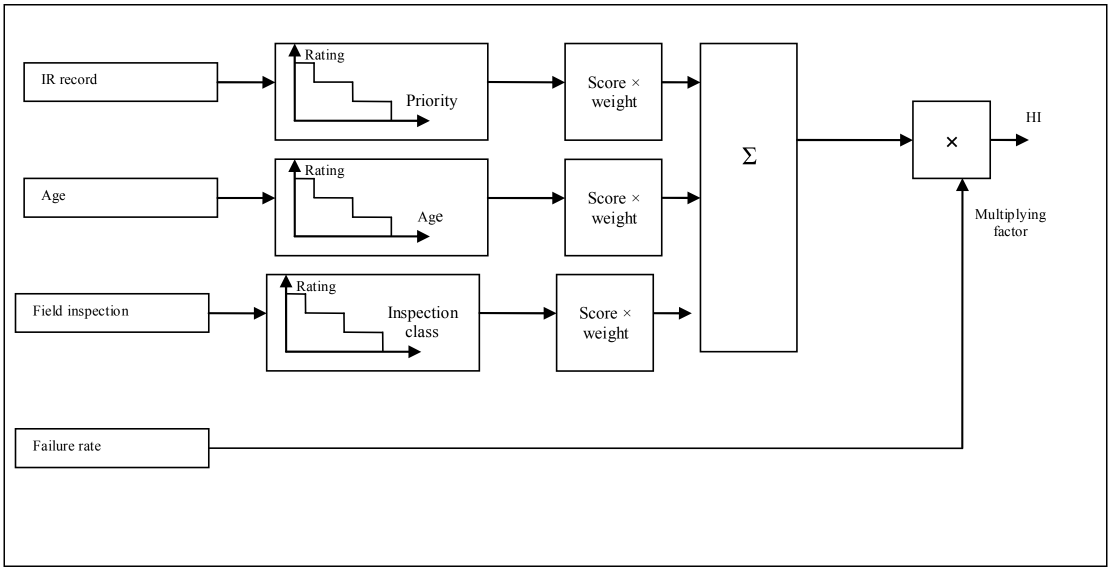

Figure 47. Distribution switchgear Health Index flowchart.

Table 49. Distribution switchgear parameter #1: age/condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	Less than 20 years old
B	3	20-40 years old
C	2	41-60 years old
D	1	61-70 years old
E	0	> 70 years old

Table 50. Distribution switchgear parameter #2: IR record condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	Priority = D
B	3	Priority = C
C	2	Priority = B
D	1	Priority = A
E	0	Priority = D

Table 51. Distribution switchgear parameter #3: field inspection condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	Inspection code = D
B	3	Inspection code = C
C	2	Inspection code = B
D	1	Inspection code = A
E	0	Inspection code = D

Table 52. Distribution switchgear parameter #4: failure rate criteria

Condition Factor	Multiplying Factor	Condition Criteria Description
A	1	M < 0.05
B	0.9	0.05 <= M < 0.1
C	0.8	0.1 <= M < 0.2
D	0.7	0.2 <= M < 0.4
E	0.6	M >= 0.4

Where M = failure rate x age

Failure rate for distribution switchgear = 0.0048, calculated based on IEEE Gold book (IEEE Std 493-1997).

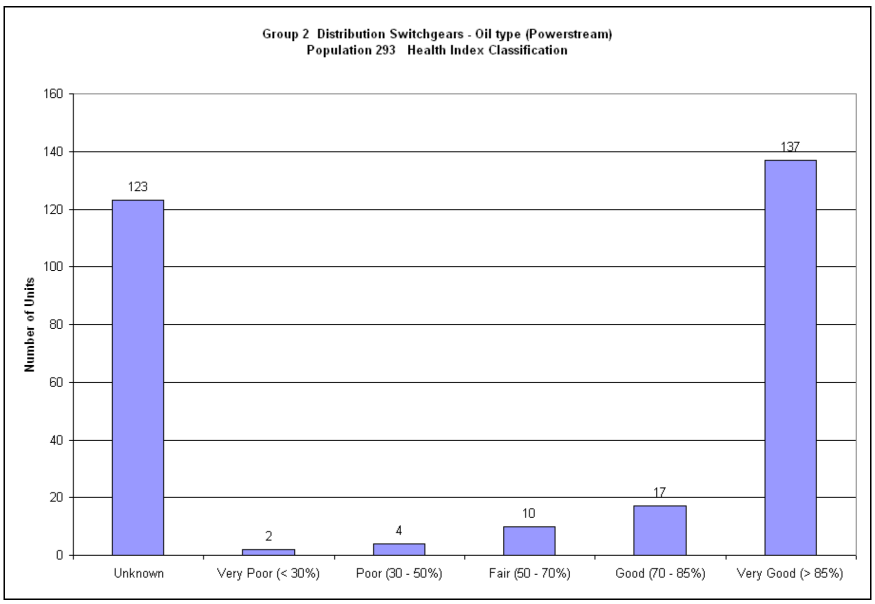

Figure 48. Distribution switchgear (oil type) Health Index histogram.

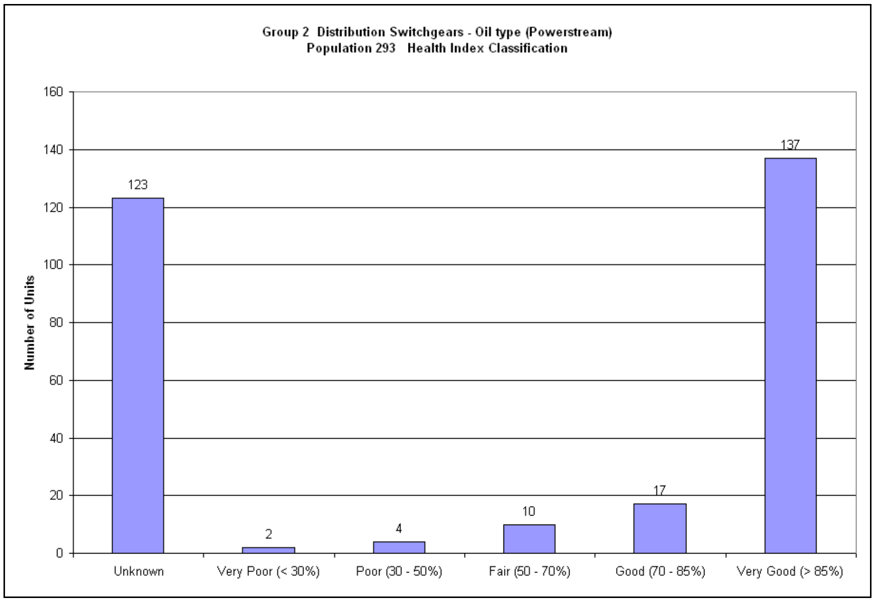

Figure 49. Distribution switchgear (air type) Health Index histogram.

Failure Probability Curves

The distribution switchgear failure probability (hazard rate) curve is based on a Weibull curve, which is calibrated to match the historic failures experienced by PowerStream.

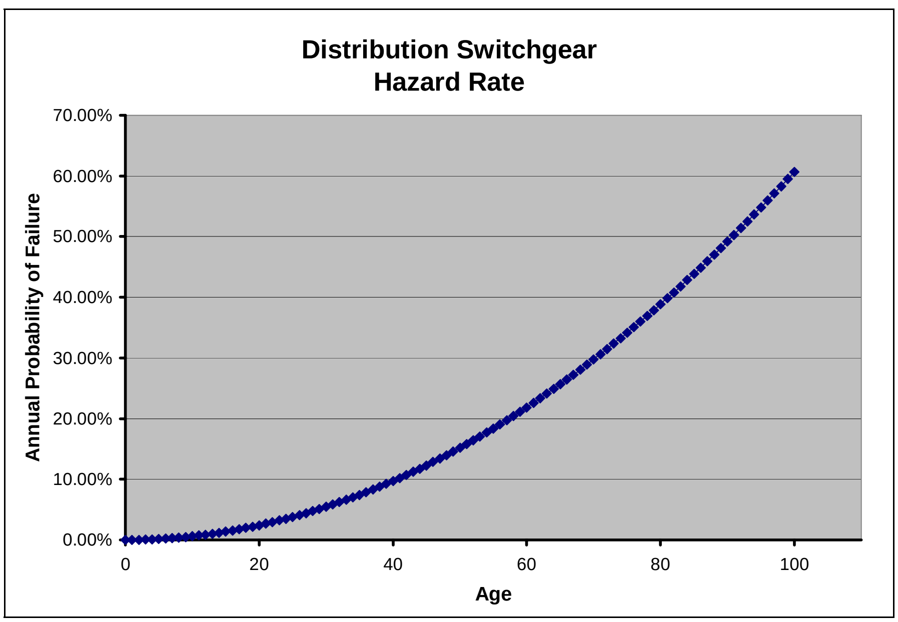

Figure 50. Distribution switchgear hazard rate curve.

Failure Effects

The failure effects by customers served are summarized in Figure 51 below.

Description	Loss of Peak Load (kW)	Outage Duration (hours)	Unsupplied Energy (kWh)	Consequence Cost due to Unsupplied Peak Demand	Consequence Cost due to Unsupplied Energy	Consequence Cost
Industrial and Commercial Customers	3,780	3	16,380	$75,600	$163,800	$239,400
Residential Subdivisions	1,440	3	4,320	$28,800	$43,200	$72,000

Figure 51. Distribution switchgear failure effects.

The failure effects were provided by PowerStream, and are based on the following assumptions:

- 90% of the switchgears supply Industrial/Commercial Customers. On average each "loop" has a maximum of 10,000 connected kVA. On average there are 10 switchgears in a "loop", each switchgear supplies two customers each with an average XFMR size of 500 kVA at an assumed L.F. of 70% & 90% P.F. Upon a switchgear failure, one-half of the loop (on average 5 switchgears) will be lost for 3 hours, while the failed switchgear will take a total of 8 hrs for replacement. One-half of the loop means 5 x 2 x 500 kVA x 0.7 x 0.9 = 3150 kW for 3 hour (9,450 kWhrs). For the unit that failed we have 2 x 500 kVA x 0.7 x 0.9 = 630 kW for 5 hours (3 hours have already lapsed) = 3,150 kWhrs.

- 10% of the switchgears supply Residential Subdivisions. On average Switchgear-to-Switchgear there are thirty 50 kVA transformers and each transformer on average has 8 customers and each customer on average has a peak load of 4 kW. The Normal open point (N.O.) is located at midpoint, therefore 15 transformers per phase on each side or 45 transformers in total (for the 3-phases). Upon a switchgear failure, one-half of the loop (on average 45 transformers, 360 customers or 1440 kW) will be lost for 3 hours (time taken to isolate/switch & restore). This means 45 xfmrs x 8 customers x 4 kW or a peak load of 1,440 kW for 3 hours or 4,320 kWhrs.

Intervention Mode

The intervention mode modeled for distribution switchgear is replacement in-kind. The replacement costs were provided by PowerStream, and are summarized in Figure 52 below.

Switchgear Type	**Total Replacement Cost** (lab. + material + overhead)
PMH Gear	$30,000
PMO Gear	$30,000
SF6 Gear	$56,000
Vista Grar	$99,000

Figure 52. Distribution Switchgear Replacement Costs.

Replacement Program Results

The economic model projects the optimal intervention timing for each asset analyzed. The program charts are generated by combining the optimal intervention timings and the associated capital costs. The raw replacement program charts (Figure 53 and Figure 54) shows results for switchgear with complete demographic data (i.e., type and size).

Program results were calculated for two scenarios: assuming all loads were residential, and assuming all loads were commercial/industrial.

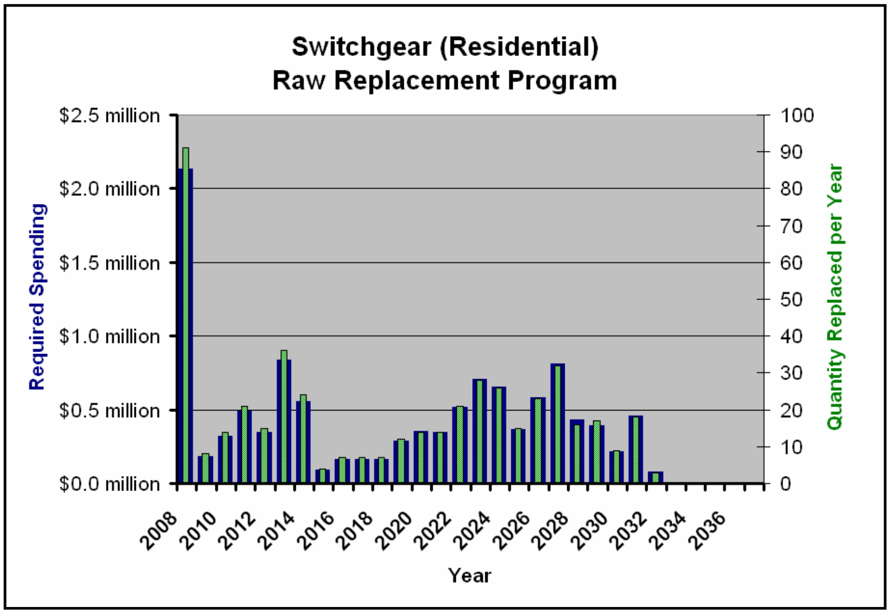

Figure 53. Distribution Switchgear Raw Replacement Program (Residential).

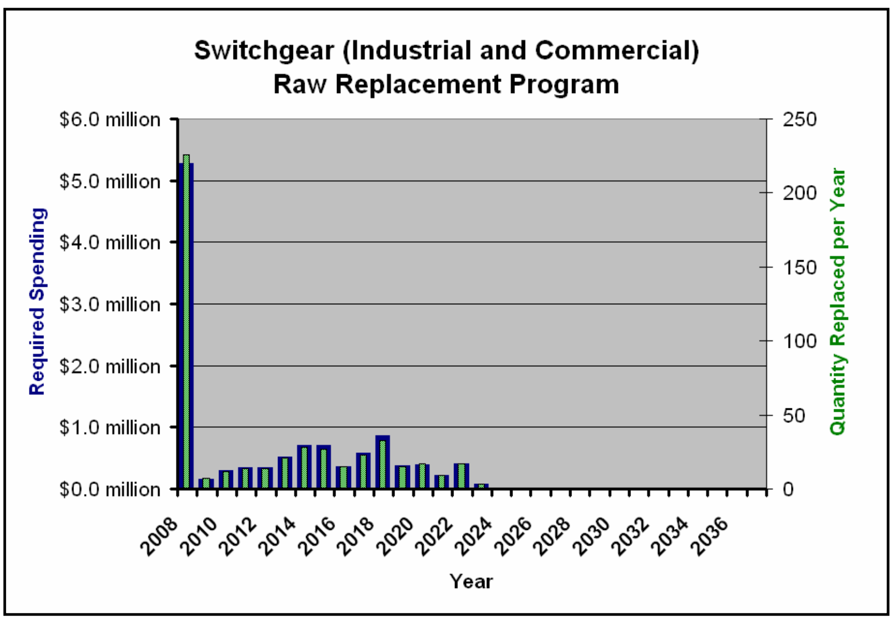

Figure 54. Distribution Switchgear Raw Replacement Program (Industrial and Commercial).

The projected failures (Figure 55 and Figure 56) account for system-wide annual failures. The replacement risk is an estimate of the reactive replacement spending associated with the projected failures. The planned and reactive spending programs are extrapolated to account for missing demographic data.

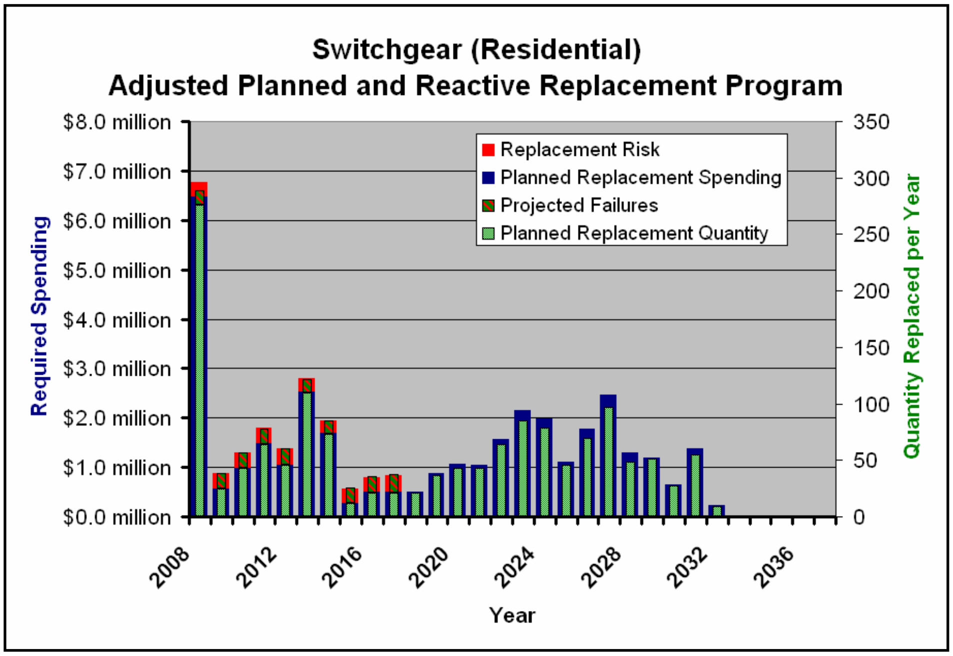

Figure 55. Distribution Switchgear Extrapolated Program.

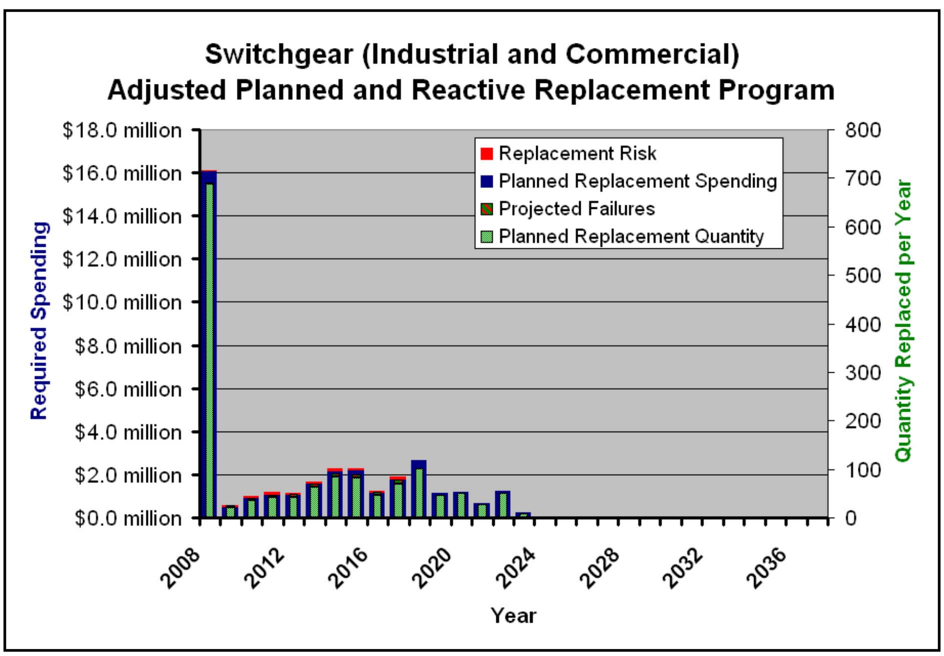

Figure 56. Distribution Switchgear Extrapolated Program.

The program results were averaged based on the ratio of residential to industrial/commercial loads (Figure 57 and Figure 58).

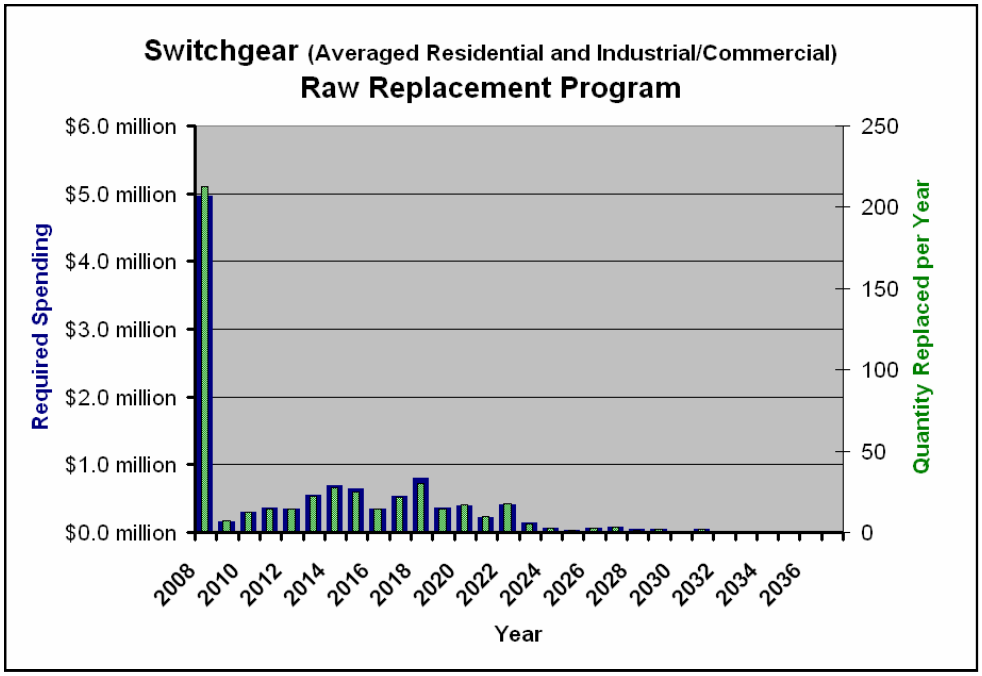

Figure 57. Distribution Switchgear Extrapolated Program.

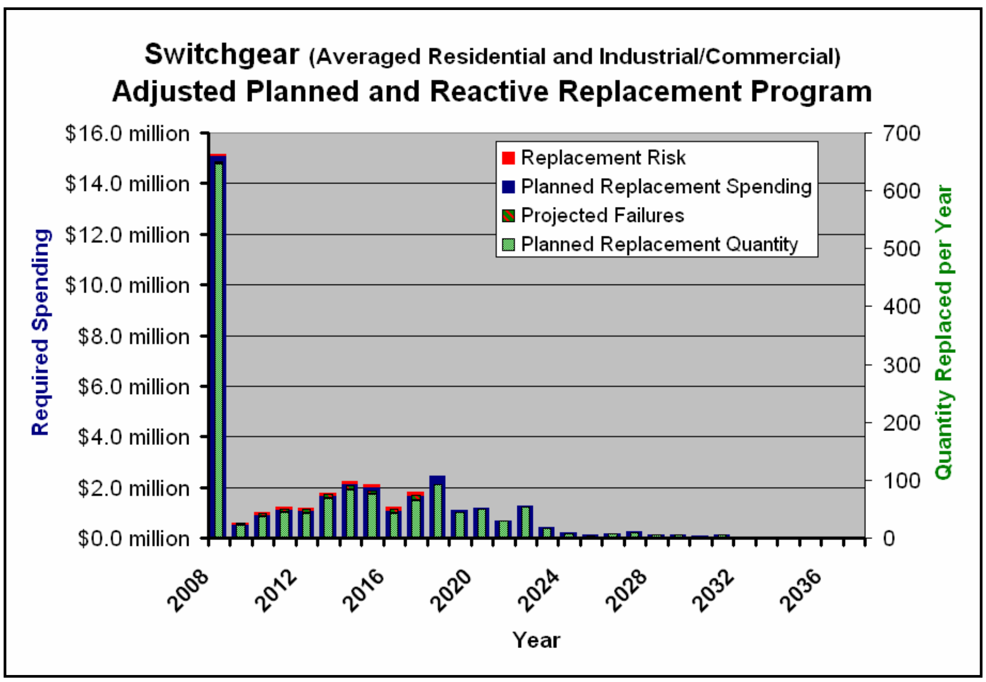

Figure 58. Distribution Switchgear Extrapolated Program.

<u>Conclusions</u>

- Recommendations:
    - Near-term switchgear replacements are warranted.
    - Continue collecting nameplate data and update the model.
    - Continue capturing condition data per health index formulation and update the model. This should be an ongoing process of updating and re-running to generate annual budgets.
    - Consider capturing switchgear condition and age at failure to support customized failure probability curves and health index correlations.
    - Consider full life-cycle cost, including risk cost, when purchasing new switchgear.
- Gaps:
    - Limited demographic and condition data available.

230kV Switches – Asset Class Details and Results

Summary of Asset Class
230kV switches are moderately complex assets with a moderate price per unit.

A 230 kV switch failure is assumed to have no consequence cost. No load will be lost as the remaining transformer will be able to carry the load of the companion transformer (there may be a momentary outage). No risk-based planned replacement program is recommended.

Health index formulation is based on industry best-practice.

Data Sources Available
Comprehensive demographic and condition data was made available.

Demographics
Number of units: 20
Typical life expectancy (years): 75
Estimated replacement cost: $46,280

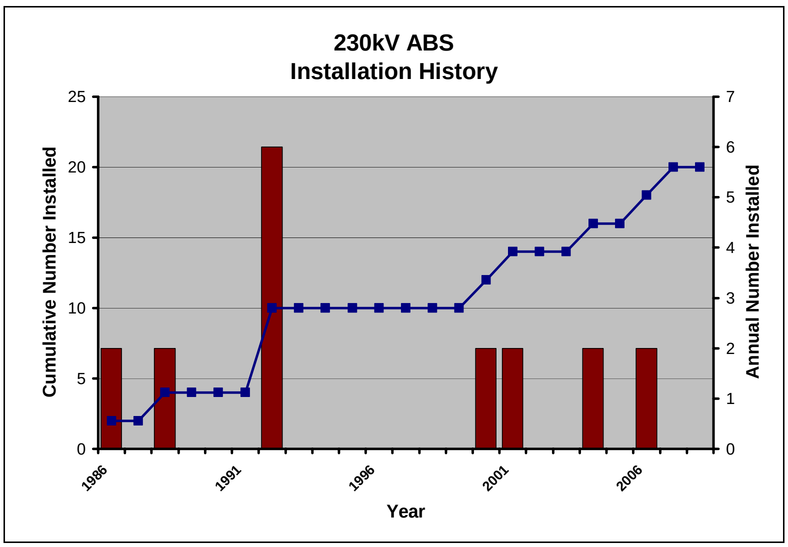

Figure 59. 230kV switches installation history.

Asset Degradation

This asset group consists of transmission and substation air break switches, and distribution fused switches. The primary function of switches is to allow isolation of line sections or equipment for maintenance, safety or other operating requirements. While some categories of switches are rated for load interruption, others are designed to be operated only under no load conditions. These switches can be operated only when the current through the switch is zero or near zero (e.g. line charging current). Disconnect switches are sometimes provided with padlocks to allow staff to obtain work permit clearance with the switch handle locked in the open position.

In general, line switches consist of mechanically movable copper blades supported on insulators and mounted on metal bases. Their operating or control mechanism can be either a simple hook stick or a manual gang. Since they do not typically need to interrupt short circuit currents, disconnect switches are relatively simple in design compared to circuit breakers.

Air break switches isolate equipment or sections of line. Air serves as the insulating medium between contacts when these switches are in the open position. Air break switches must have the capability of providing visual confirmation of the open/close position.

The main degradation processes associated with line switches include:

- Corrosion of steel hardware or operating rod,
- Mechanical deterioration of linkages,
- Switch blades falling out of alignment, which may result in excessive arcing during operation,
- Loose connections,
- Insulator damage,
- Missing ground connections

The rate and severity of these degradation processes depends on a number of inter-related factors including the operating duties and environment in which the equipment is installed. In most cases, corrosion or rust represents a critical degradation process. The rate of deterioration depends heavily on environmental conditions in which the equipment operates.

Corrosion typically occurs around the mechanical linkages of these switches. Corrosion can cause seizing. When lubrication dries out the switch operating mechanism may seize making the disconnect switch inoperable. While a lesser mode of degradation, air pollution also can affect support insulators. Typically, this occurs in heavy industrial areas or where road de-icing salt is used.

The condition assessment of switches involves visual inspections which can reveal the extent of corrosion on main contacts, condition of stand-off insulators and operating mechanism. Thermographic surveys using infrared cameras represent one of the easiest and most cost-effective tests to locate hot spots on switches.

The following parameters can be considered in establishing the asset health index formulation:

- Condition of switch blades (contacts)
- Operating arm and switch mounting
- Condition of arcing horns or arc suppressors
- Condition of operating handle padlocks
- Condition of operating mechanism
- Age of disconnect switch
- Expert feedback

The average life expectancy of switches is approximately 40 years. Consequences of switch failure may include customer interruption and health and safety consequences for operators.

Health Index Formulation and Results

The following charts provide the main condition parameters that were used in the PowerStream asset condition assessment and the weights assigned to each. Details of the Health Index formulation are provided in the tables.

Table 53. 230kV switches Health Index parameters and weights

#	230kV Switch Condition Parameters	Weight
1	Age	3
2	Expert Feedback	10
3	Load	3
4	Switch Contact	5
5	Blade/Arm	5
6	Mechanism	5
7	Fuse	3
8	Arc Break	5
9	Lock/Handle	1

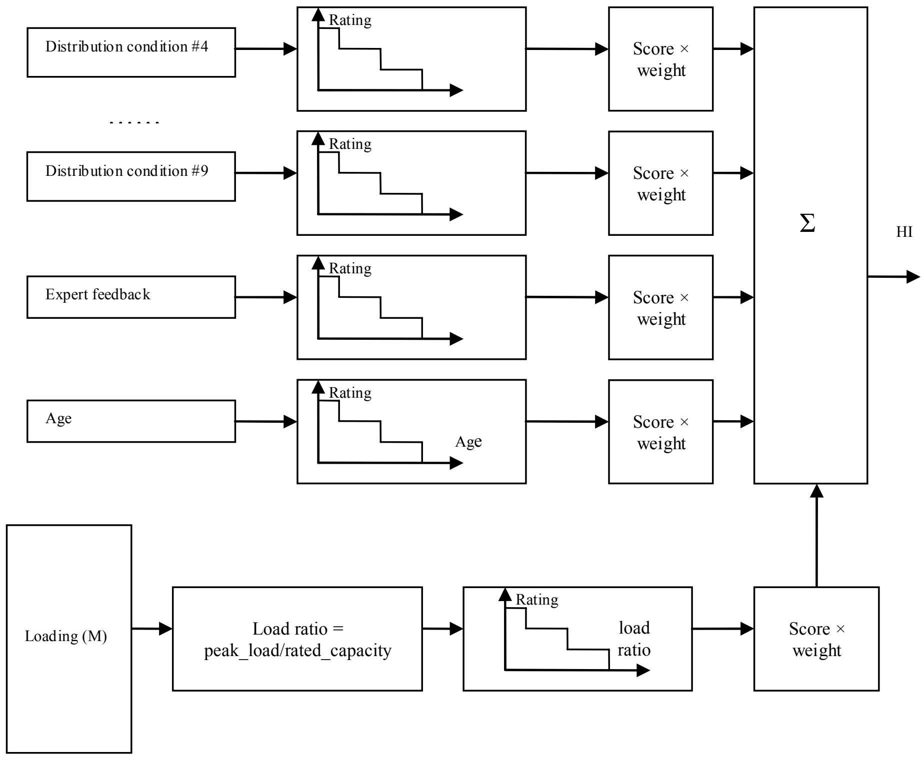

Figure 60. 230kV switches Health Index flowchart.

Table 54. 230kV switches parameter #1: age/condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	<10 years old
B	3	10-19 years old
C	2	20-29 years old
D	1	30-39 years old
E	0	>=40 years old

Table 55. 230kV switches parameter #2: expert feedback

Condition Factor	Factor	Condition Criteria Description
A	4	Excellent
B	3	Very Good
C	2	Good
	N/A	Unknown

Table 56. 230kV switches parameter #3: loading condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	N < 1
B	3	1 <= N < 1.1
C	2	1.1 <= N < 1.2
D	1	1.2 <= N < 1.4
E	0	N >= 1.4

Where N = peak_load / rated_capacity

Table 57. 230kV switches parameter #4: switch contact condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	[0,200)
B	3	[200, 250)
D	1	[250, 300)
E	0	[300, ∞)

Table 58. 230kV switches parameters #5-9: inspection asset condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	Excellent
B	3	Very Good
C	2	Good
	N/A	Unknown

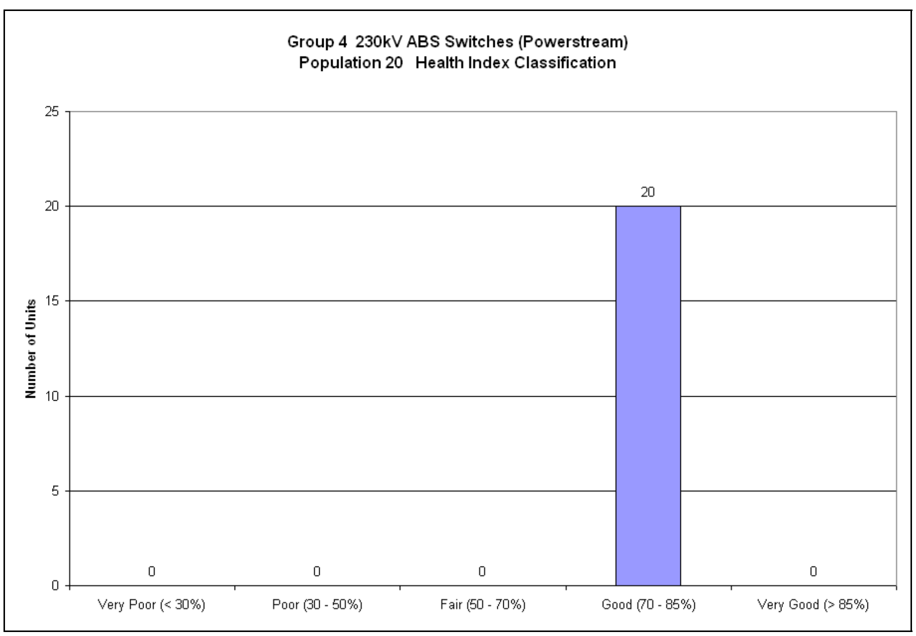

Figure 61. 230kV switches Health Index histogram.

Failure Probability Curves

The 230kV switch failure probability (hazard rate) curve is based on a normal curve with a mean life equal to 75 years.

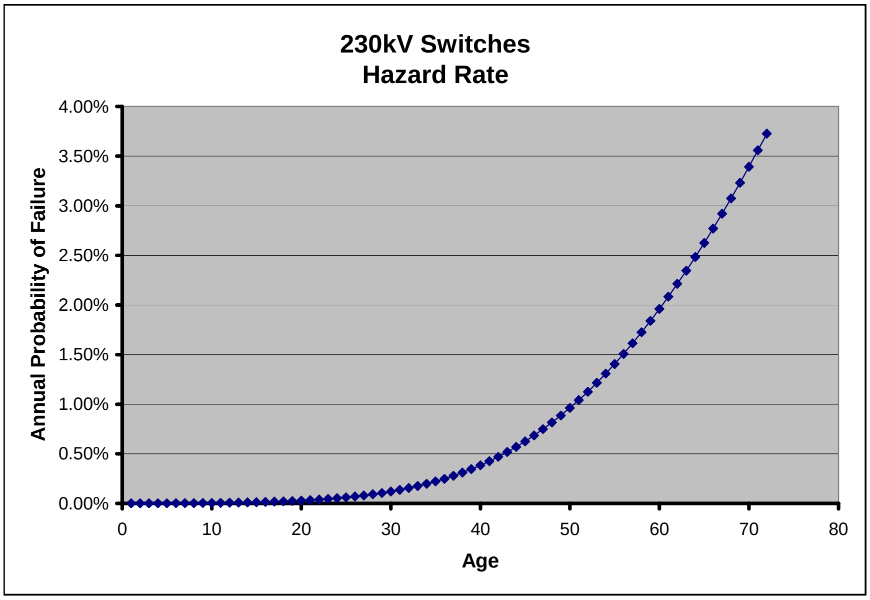

Figure 62. 230kV switches hazard rate curve.

Failure Effects

The dominant failure mode assessed for a 230kV switch is catastrophic failure requiring replacement.

The failure effects were provided by PowerStream, and are based on the following assumptions:

- Loss of a 230 kV switch, no load will be lost as the remaining transformer will be able to carry the load of the companion transformer. There may be a momentary outage.

Intervention Mode

The intervention mode modeled for 230kV switches is replacement in-kind. The replacement costs vary by type and size. The replacement costs were provided by PowerStream.

Replacement Program Results
The economic model projects the optimal intervention timing for each asset analyzed. The program charts are generated by combining the optimal intervention timings and the associated capital costs. The replacement program chart (Figure 63) shows results for switches with complete demographic data (i.e., type and size). Due to no loss of load upon switch failure, no replacement program is recommended.

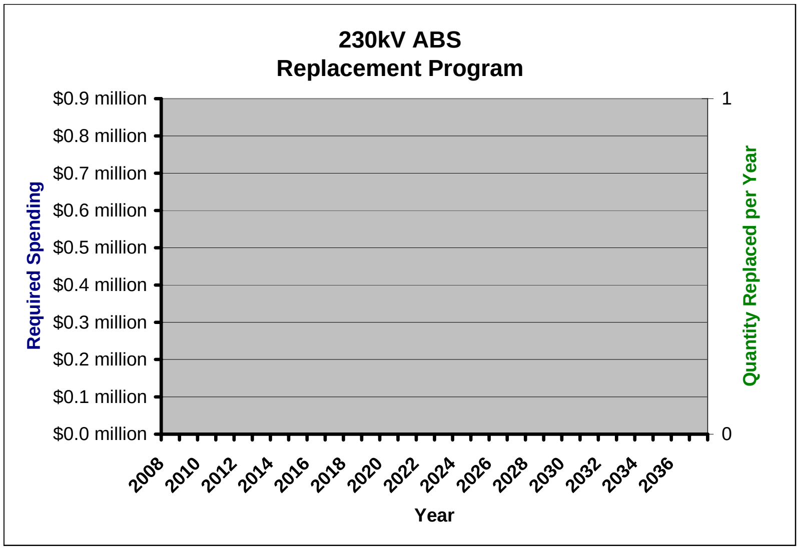

Figure 63. 230kV switches replacement program.

The projected failures (Figure 64) account for system-wide annual failures. The replacement risk is an estimate of the reactive replacement spending associated with the projected failures.

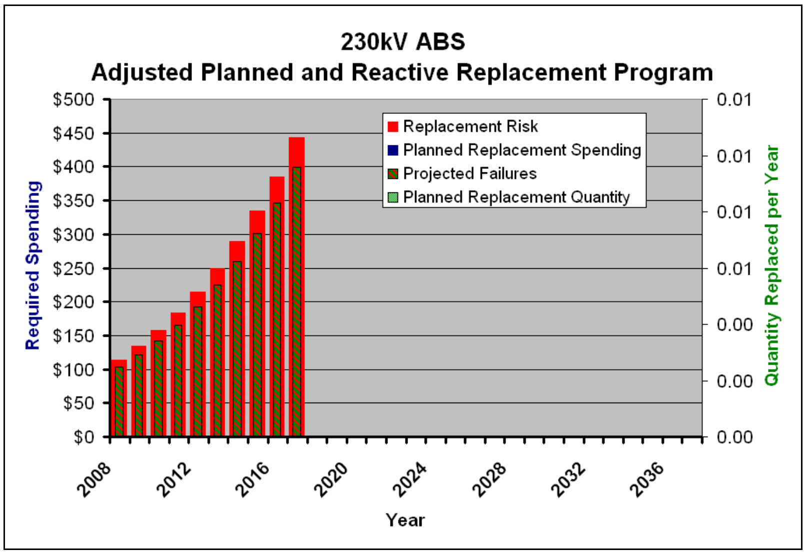

Figure 64. 230kV switches planned and reactive program.

<u>Conclusions</u>

- Recommendations:
    - No risk-based planned replacement program is recommended for 230kV switches.
    - Continue capturing condition data per health index formulation and update the model. This should be an ongoing process of updating and re-running to generate annual budgets.
    - Consider capturing switch condition and age at failure to support customized failure probability curves and health index correlations.
    - Consider full life-cycle cost, including risk cost, when purchasing new switches.
- Gaps:
    - None.

MS Primary Switches – Asset Class Details and Results

Summary of Asset Class
MS primary switches are moderately complex assets with a moderate price per unit.

Health index formulation is based on industry best-practice and data will be collected in the future.

Data Sources Available
Loading, nameplate, and general demographic data.

Demographics
Number of units: 25
Typical life expectancy (years): 40
Estimated replacement cost: $44,000 - $112,000

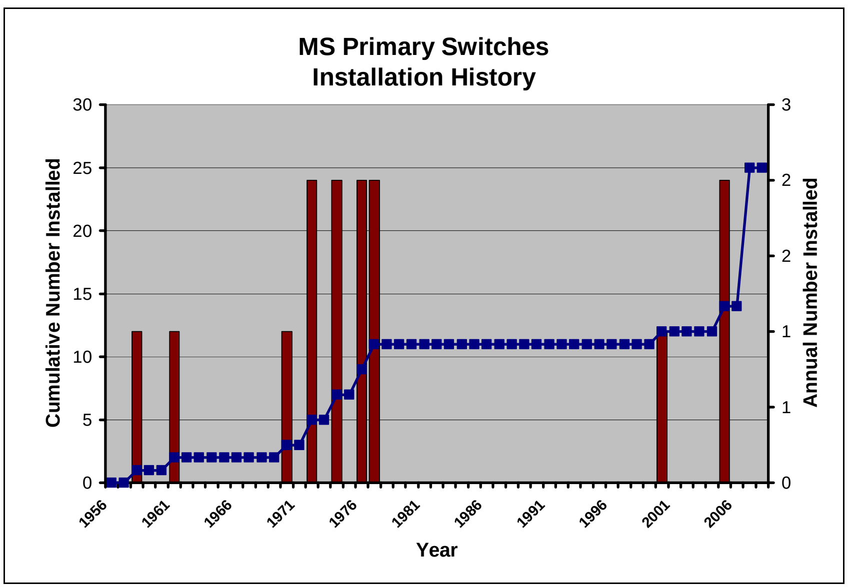

Figure 65. MS primary switches installation history.

Asset Degradation

This asset group consists of transmission and substation air break switches, and distribution fused switches. The primary function of switches is to allow isolation of line sections or equipment for maintenance, safety or other operating requirements. While some categories of switches are rated for load interruption, others are designed to be operated only under no load conditions. These switches can be operated only when the current through the switch is zero or near zero (e.g. line charging current). Disconnect switches are sometimes provided with padlocks to allow staff to obtain work permit clearance with the switch handle locked in the open position.

In general, line switches consist of mechanically movable copper blades supported on insulators and mounted on metal bases. Their operating or control mechanism can be either a simple hook stick or a manual gang. Since they do not typically need to interrupt short circuit currents, disconnect switches are relatively simple in design compared to circuit breakers.

Air break switches isolate equipment or sections of line. Air serves as the insulating medium between contacts when these switches are in the open position. Air break switches must have the capability of providing visual confirmation of the open/close position.

The main degradation processes associated with line switches include:

- Corrosion of steel hardware or operating rod,
- Mechanical deterioration of linkages,
- Switch blades falling out of alignment, which may result in excessive arcing during operation,
- Loose connections,
- Insulator damage,
- Missing ground connections

The rate and severity of these degradation processes depends on a number of inter-related factors including the operating duties and environment in which the equipment is installed. In most cases, corrosion or rust represents a critical degradation process. The rate of deterioration depends heavily on environmental conditions in which the equipment operates.

Corrosion typically occurs around the mechanical linkages of these switches. Corrosion can cause seizing. When lubrication dries out the switch operating mechanism may seize making the disconnect switch inoperable. While a lesser mode of degradation, air pollution also can affect support insulators. Typically, this occurs in heavy industrial areas or where road de-icing salt is used.

The condition assessment of switches involves visual inspections which can reveal the extent of corrosion on main contacts, condition of stand-off insulators and operating mechanism. Thermographic surveys using infrared cameras represent one of the easiest and most cost-effective tests to locate hot spots on switches.

The following parameters can be considered in establishing the asset health index formulation:

- Condition of switch blades (contacts)
- Operating arm and switch mounting
- Condition of arcing horns or arc suppressors
- Condition of operating handle padlocks
- Condition of operating mechanism
- Age of disconnect switch
- Expert feedback

The average life expectancy of switches is approximately 40 years. Consequences of switch failure may include customer interruption and health and safety consequences for operators.

Health Index Formulation and Results

The following charts provide the main condition parameters that were used in the PowerStream asset condition assessment and the weights assigned to each. Details of the Health Index formulation are provided in the tables.

Table 59. 230kV switches Health Index parameters and weights

#	MS Primary Switch Condition Parameters	Weight
1	Age	3
2	Expert Feedback	10
3	Load	3
4	Switch Contact	5
5	Blade/Arm	5
6	Mechanism	5
7	Fuse	3
8	Arc Break	5
9	Lock/Handle	1

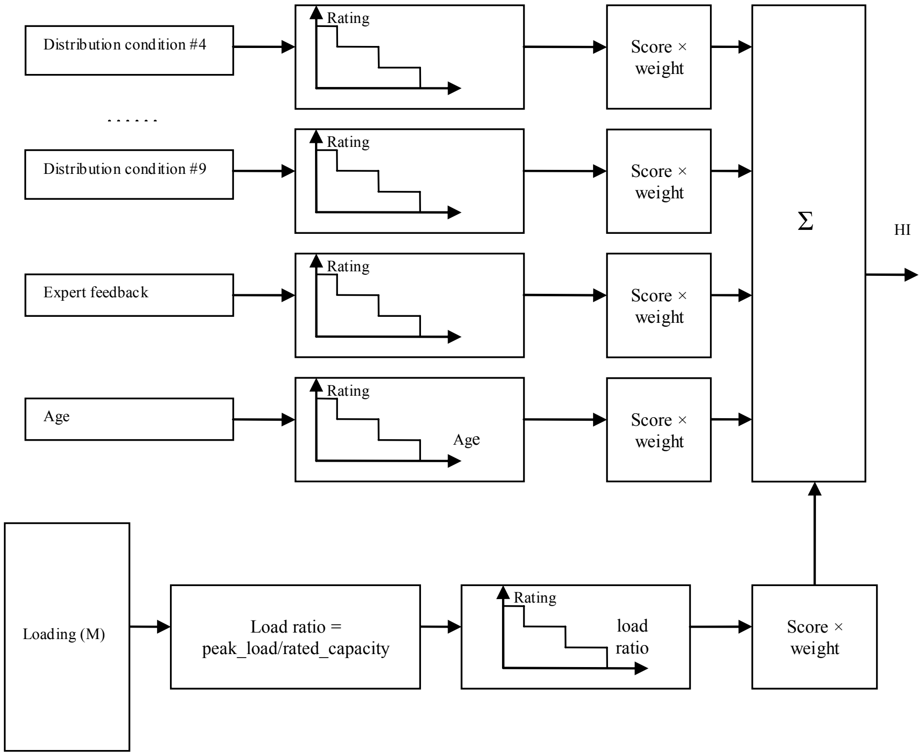

Figure 66. MS primary switches Health Index flowchart.

Table 60. MS primary switches parameter #1: age/condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	< 20 years old
B	3	20-39 years old
C	2	40-49 years old
D	1	50-59 years old
E	0	>=60 years old

Table 61. MS primary switches parameter #2: expert feedback

Condition Factor	Factor	Condition Criteria Description
A	4	Excellent
B	3	Very Good
C	2	Good
	N/A	Unknown

Table 62. MS primary switches parameter #3: loading condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	N < 1
B	3	1 <= N < 1.1
C	2	1.1 <= N < 1.2
D	1	1.2 <= N < 1.4
E	0	N >= 1.4

Where N = peak_load / rated_capacity

Table 63. MS primary switches parameter #4: switch contact condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	[0,200)
B	3	[200, 250)
D	1	[250, 300)
E	0	[300, ∞)

Table 64. MS primary switches parameters #5-9: inspection asset condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	Excellent
B	3	Very Good
C	2	Good
	N/A	Unknown

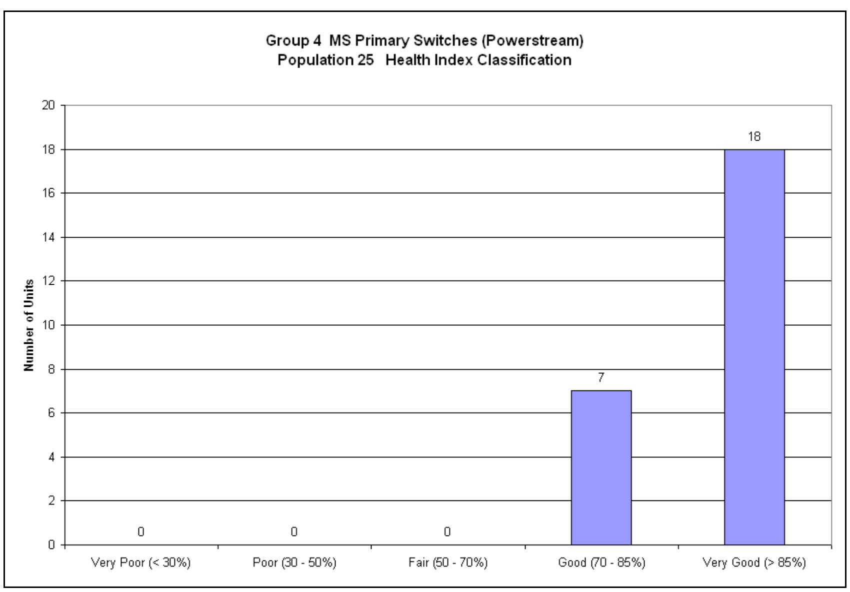

Figure 67. MS primary switches Health Index histogram.

Failure Probability Curves

The MS primary switch failure probability (hazard rate) curve is based on a normal curve with a mean life equal to 40 years.

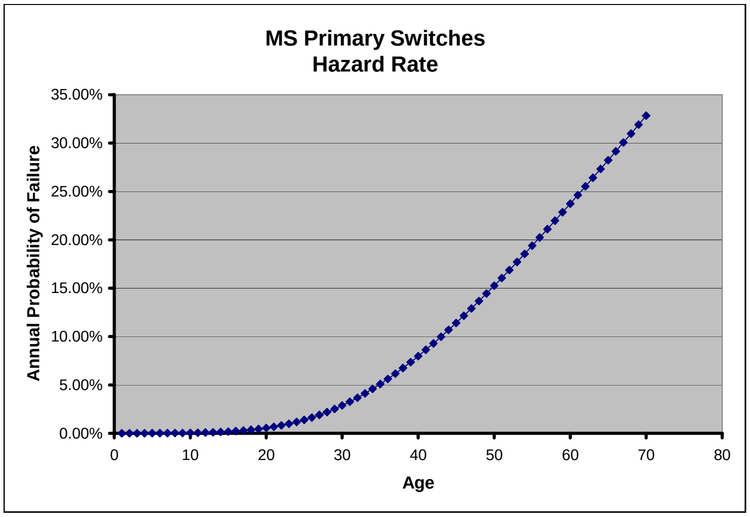

Figure 68. MS primary switches hazard rate curve.

Failure Effects

The dominant failure mode assessed for MS primary switches is catastrophic failure requiring replacement. The failure effects by type and size are summarized in **Error! Reference source not found.** below.

Description	Loss of Peak Load (kW)	Outage Duration (hrs)	Unsupplied Energy (Kwh)	Consequence Cost due to unsupplied Peak Demand (kW)	Consequence Cost due to unsupplied Energy (kWhrs)	Consequence Cost
MS Primary Switch (pole or pad mount)	7,200	3	21,600	$144,000	$216,000	$360,000

Figure 69. MS primary switches failure effects

The failure effects were provided by PowerStream, and are based on the following assumptions:

- There are 14 substations (MS's) and a total of 22 transformers totaling 200 MVA of installed capacity. Eight (8) substations (16 transformers) have two transformers; each transformer is controlled by one "Primary" switch.
- Six (6) substations have single transformers each controlled by one "Primary" switch. Therefore, loss of a primary switch (during the peak load period) at any of the substations will mean loss of about 8 MVA for a period of 3 hours (time taken to isolate and restore).

- On average, loss of a primary switch at any of the substations will mean loss of 8 MVA (7,200 MW) for a period of 3 hours (time taken to isolate and restore) or 21,600 kWhrs.

Intervention Mode

The intervention mode modeled for MS primary switches is replacement in-kind. The replacement costs vary by type and size. The replacement costs were provided by PowerStream, and are summarized in Figure 70 below.

Material Cost	Material Cost plus Overhead and Burden	Replacement Labour Hours	Replacement Labour Cost Plus Overhead and Burden	Truck Hours	Truck Cost plus Overhead and Burden	Type	Total
$30,000	$39,600	60	$3,420	30	$1,590	Pole	$44,610
$80,000	$105,600	80	$4,560	40	$2,120	Enclosure	$112,280

Figure 70. MS primary switches replacement costs.

Replacement Program Results

The economic model projects the optimal intervention timing for each asset analyzed. The program charts are generated by combining the optimal intervention timings and the associated capital costs. The replacement program chart (Figure 71) shows results for transformers with complete demographic data (i.e., type and size).

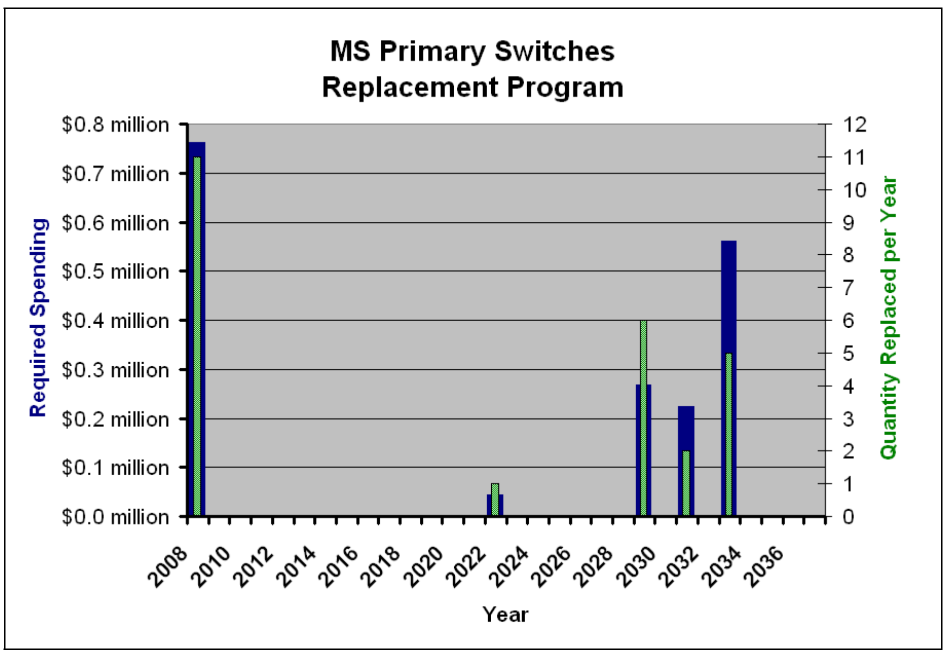

Figure 71. MS primary switches replacement program.

The projected failures (Figure 72) account for system-wide annual failures. The replacement risk is an estimate of the reactive replacement spending associated with the projected failures.

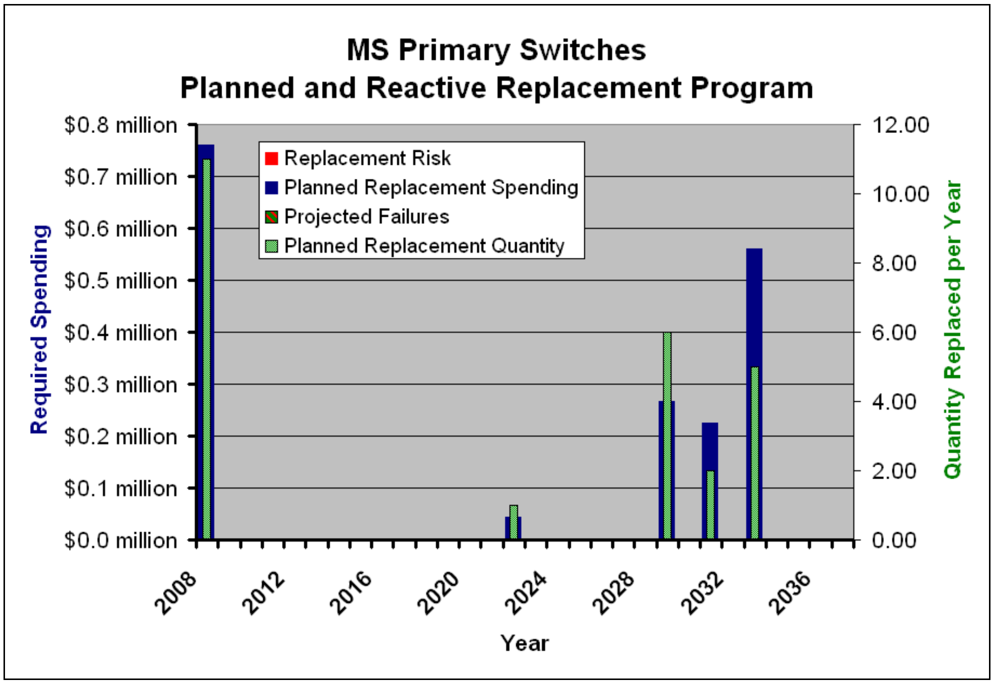

Figure 72. MS primary switches planned and reactive program.

<u>Conclusions</u>

- Recommendations:
  - Near-term switch replacements are warranted.
  - Continue collecting nameplate data and update the model.
  - Continue capturing condition data per health index formulation and update the model. This should be an ongoing process of updating and re-running to generate annual budgets.
  - Consider capturing switch condition and age at failure to support customized failure probability curves and health index correlations.
  - Consider full life-cycle cost, including risk cost, when purchasing new transformers.
- Gaps:
  - Loading is based on average configuration as supplied by PowerStream.

Station Capacitors – Asset Class Details and Results

Summary of Asset Class
Station capacitors are moderately complex assets with a moderate price per unit.

The dominant failure mode assessed for station capacitors is a can failure. Loss of a single unit or the entire capacitor bank will not affect station load. Capacitor bank replacements are justified based on increasing risk of can failures and associated annual costs.

Health index formulation is based on industry best-practice, and data will be collected in the future.

Data Sources Available
Nameplate and general demographic data.

Demographics
Number of units: 4 banks
Typical life expectancy (years): 25 years for a can
Estimated replacement cost: $110,000 for a bank

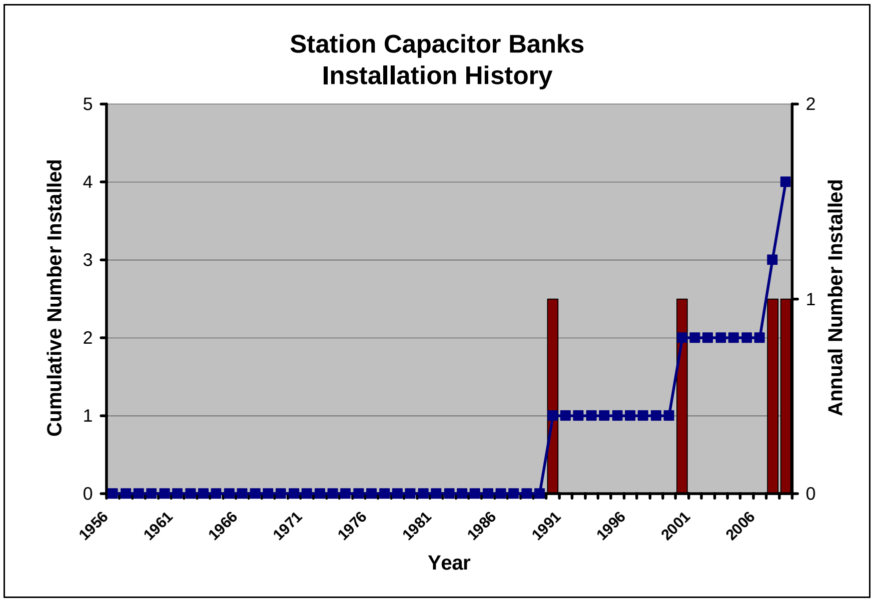

Figure 73. Station capacitors installation history.

Asset Degradation

The primary function of capacitors is to improve the quality of the electrical supply and the efficient operation of the power system. The major applications include power factor improvement and voltage regulation.

In practical implementation, such asset functions in the form of capacitor bank, i.e., a combination of various capacitor units. The operation of capacitors requires much fewer switching-on/switching-off operations. The main degradation processes associated with capacitors include:

- Unbalance due to fuse (either internally or externally) failure
- Capacitor unit fluid leaking
- Insulator problem

The rate and severity of these degradation processes depends on a number of inter-related factors including the operating duties and environment in which the equipment is installed. The rate of deterioration depends heavily on environmental conditions in which the equipment operates.

In externally fused, fuseless or unfused capacitor banks, the failed element within the can is short-circuited by the weld that naturally occurs at the point of failure (the element fails short-circuited). This short circuit puts out of service the whole group of elements, increasing the voltage on the remaining groups. Several capacitor elements breakdowns may occur before the external fuse (if exists) removes the entire unit. The external fuse will operate when a capacitor unit becomes essentially short circuited, isolating the faulted unit. Internally fused capacitors have individual fused capacitor elements that are disconnected when an element breakdown occurs (the element fails opened). The risk of successive faults is minimized because the fuse will isolate the faulty element within a few cycles. The degree of unbalance introduced by an element failure is less than that which occurs with externally fused units (since the amount of capacitance removed by blown fuse is less) and hence a more sensitive unbalance protection scheme is required when internally fused units are used.

Capacitor unit fluid leaking is mainly due to mechanical damage to the capacitor case. Insulator problems can be either insulator crack, or pollution on insulators.

The condition assessment of capacitors involves visual inspections which can reveal the extent of problems, as well as utility experts' feedback that tells the general status. Thermographic surveys using infrared cameras represent one of the easiest and most cost-effective tests to locate hot spots on capacitors.

The following parameters can be considered in establishing the asset health index formulation:

- Expert feedback on capacitors
- Visual inspection on capacitors
- Visual inspection on insulators
- Age of capacitors

- Expert feedback

The average life expectancy of capacitors is approximately 30 years. This can, however, be prolonged by keeping on replacing the faulty units. Consequences of capacitors failure may include local under-voltage and lack of reactive power for operators.

Health Index Formulation and Results

The following charts provide the main condition parameters that were used in the PowerStream asset condition assessment and the weights assigned to each. Details of the Health Index formulation are provided in the tables.

Table 65. Station capacitors Health Index parameters and weights

#	Station Capacitor Condition Parameters	Weight
1	Age	10
2	Expert feedback	15
3	Visual inspection	5
4	Insulators	1
5	Total faulty units	10

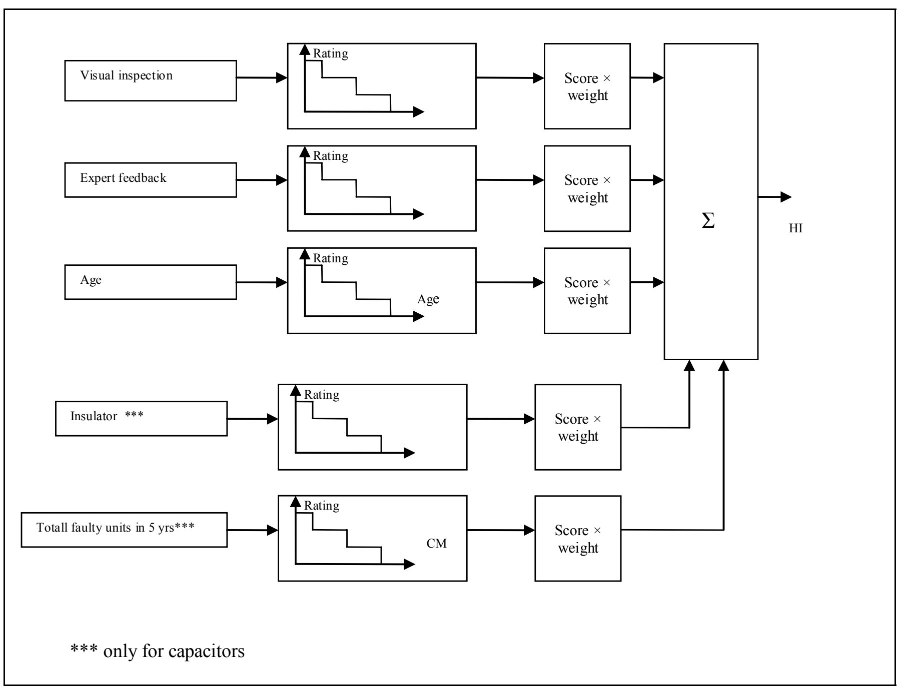

Figure 74. Station capacitors Health Index flowchart.

Table 66. Station capacitors parameter #1: age/condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	<20 years old
B	3	20-29 years old
C	2	30-39 years old
D	1	40-49 years old
E	0	>=50 years old

Table 67. Station capacitors parameter #2: expert feedback condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	Excellent
B	3	Very Good
C	2	Good
	N/A	Unknown

Table 68. Station capacitors parameter #3: visual inspection condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	Excellent
B	3	Very Good
C	2	Good
	N/A	Unknown

Table 69. Station capacitors parameter #4: insulator condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	Excellent
B	3	Very Good
C	2	Good
	N/A	Unknown

Table 70. Station capacitors parameter #5: total faulty unit condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	No replacement in 5 years
B	3	1 replacement in 5 years
C	2	2 replacements in 5 years
D	1	4 replacements in 5 years
E	0	More than 4 replacements in 5 years

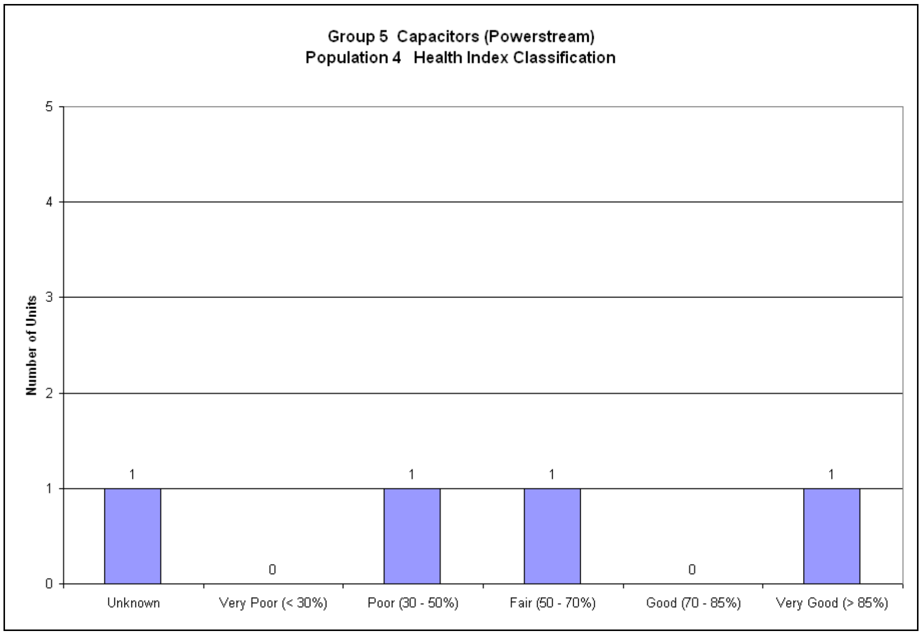

Figure 75. Station capacitors Health Index histogram.
(**Note:** the "unknown" cap bank is not in-service as yet, scheduled in 2009)

Failure Probability Curves
The station capacitor cans failure probability (hazard rate) curve is based on a normal curve with a mean life equal to 25 years.

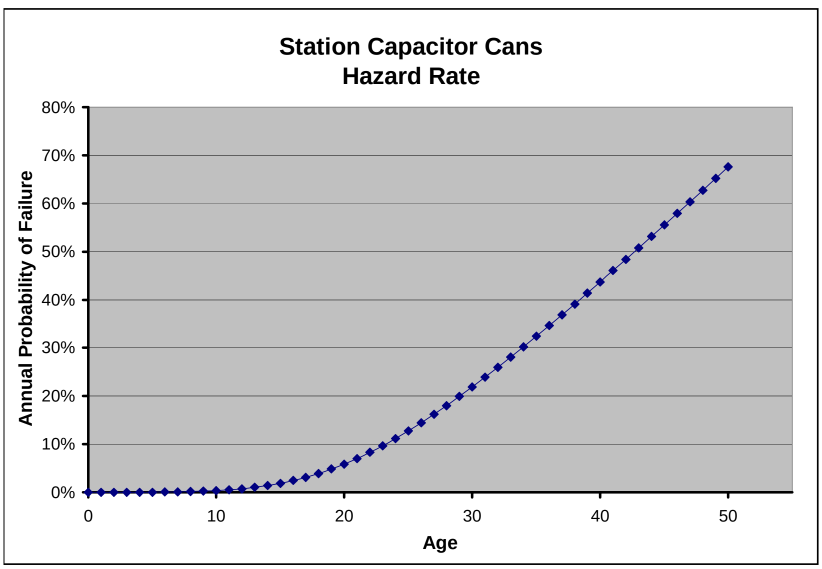

Figure 76. Station capacitors hazard rate curve.

Failure Effects
The dominant failure mode assessed for station capacitors is a can failure requiring replacement of the can. As provided by PowerStream, the loss of a single unit or the entire capacitor bank will not affect the station load.

Intervention Mode
The intervention mode modeled for station capacitors is capacitor bank replacement in-kind. The replacement costs vary by type and size. The replacement costs were provided by PowerStream.

Replacement Program Results
The economic model projects the optimal intervention timing for each asset analyzed. The program charts are generated by combining the optimal intervention timings and the associated capital costs. The replacement program chart (Figure 77) shows results for the station capacitors.

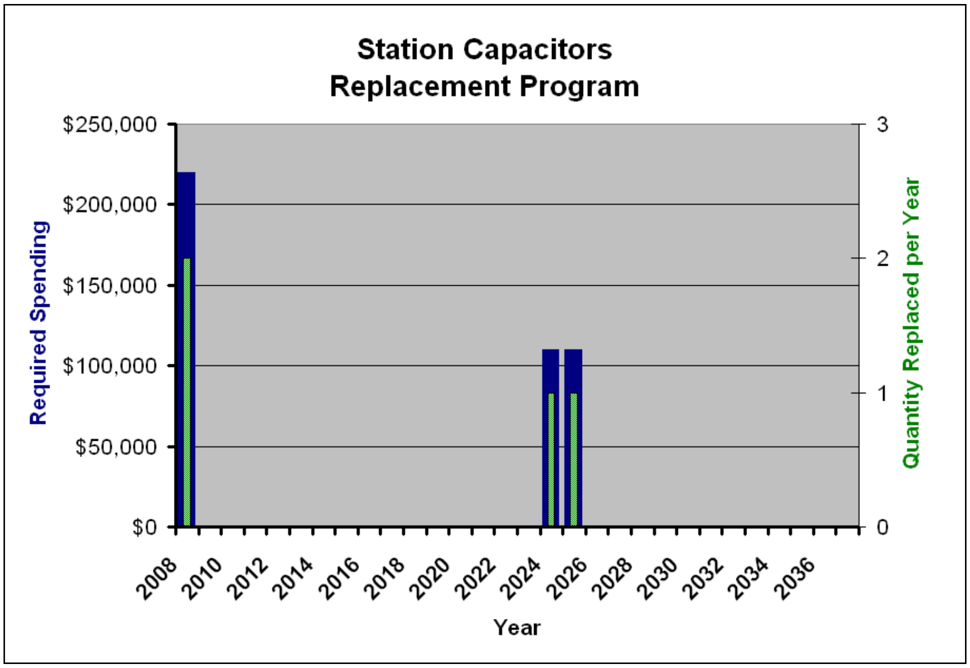

Figure 77. Station capacitors replacement program.

The projected failures (Figure 78) account for annual can failures. The replacement risk is an estimate of the reactive replacement spending associated with the projected can failures.

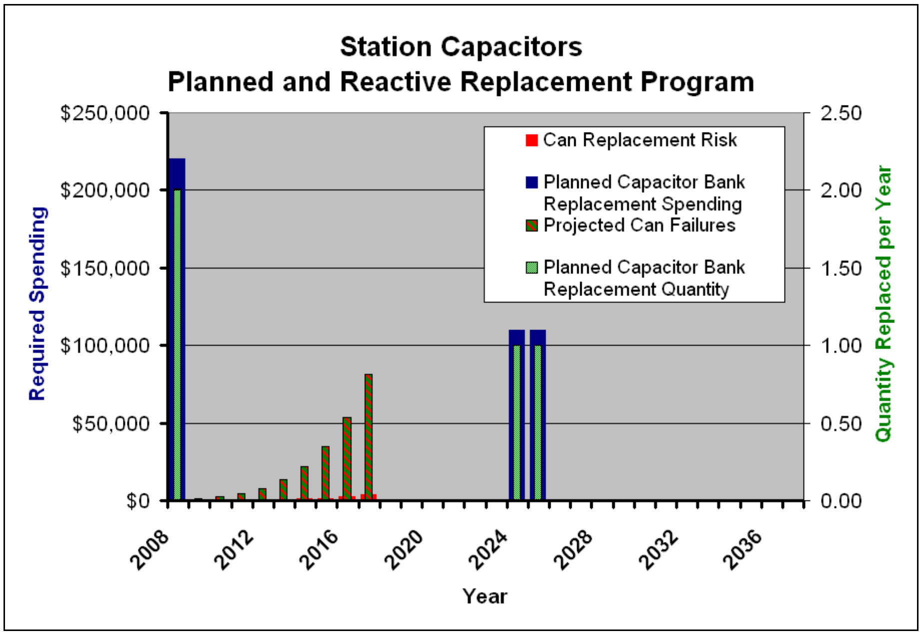

Figure 78. Station capacitors planned and reactive program.

<u>Conclusions</u>

- Recommendations:
  - Capacitor bank replacements are justified based on increasing risk of can failures and associated annual costs.
  - Near-term capacitor bank replacements are warranted.
  - Continue capturing condition data per health index formulation and update the model. This should be an ongoing process of updating and re-running to generate annual budgets.
  - Consider capturing can condition and age at failure to support customized failure probability curves and health index correlations.
  - Consider full life-cycle cost, including risk cost, when purchasing new capacitor banks.
- Gaps:
  - None.

Station Reactors – Asset Class Details and Results

Summary of Asset Class
Station reactors are moderately complex assets with a moderate price per unit.

A station reactor failure is assumed to have no consequence cost. Loss of a station reactor, no load will be lost as the remaining transformer will be able to carry the load of the companion transformer, there maybe a momentary outage. No risk-based planned replacement program is recommended.

Health index formulation is based on industry best-practice.

Data Sources Available
Nameplate and general demographic data.

Demographics
Number of units: 20
Typical life expectancy (years): 75
Estimated replacement cost: $41,270

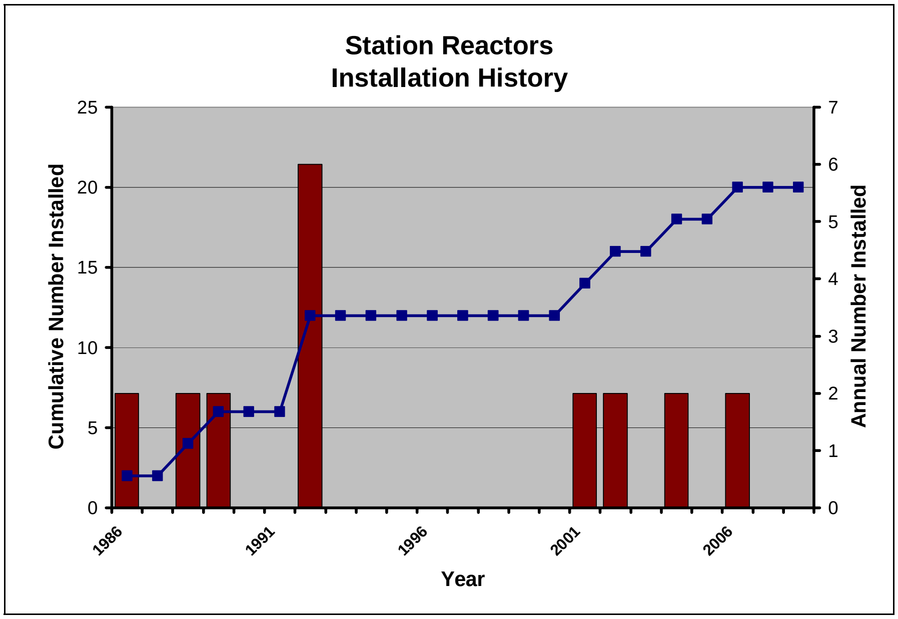

Figure 79. Station reactors installation history.

Asset Degradation

The primary function of reactors is to limit the short circuit current of a line when there is short circuit. It can also be used to absorb reactive power, or as part of filtering circuit.

When being used as a current limiting component, a reactor is connected in series with other components in a line. When being used to absorb reactive power, a shunt reactor is adopted. Because of such character, in normal case a reactor does not require switching operation once it is put in service.

Unlike other assets, reactors are almost maintenance free. They can be in operation for decades without any failure reported. The condition assessment of reactors involves mainly visual inspections and expert feedbacks.

The average life expectancy of reactors can be over 70 years.

Health Index Formulation and Results

The following charts provide the main condition parameters that were used in the PowerStream asset condition assessment and the weights assigned to each. Details of the Health Index formulation are provided in the tables.

Table 71. Station reactors Health Index parameters and weights

#	Distribution Condition Parameters	Weight
1	Age	10
2	Expert feedback	15
3	Visual inspection	5

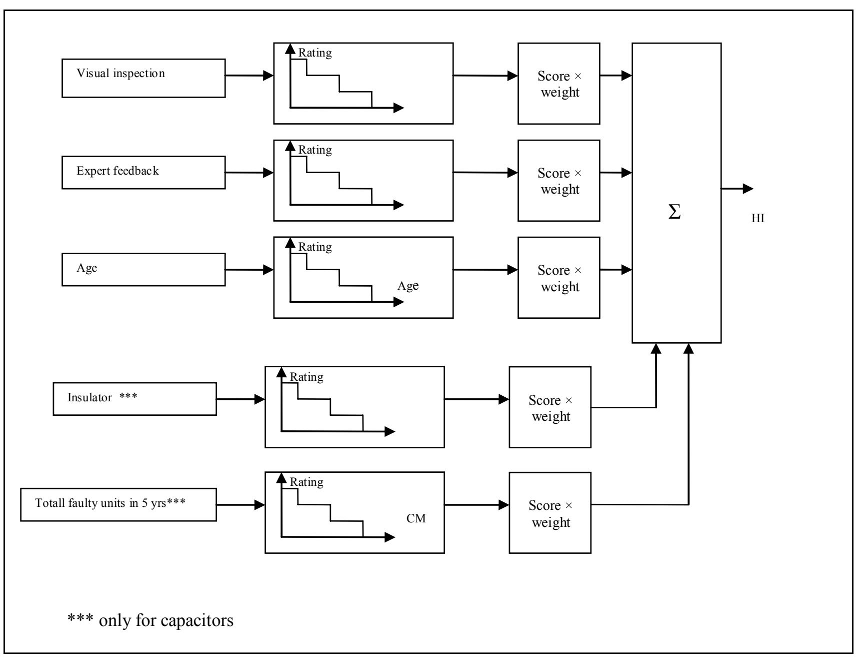

Figure 80. Station reactors Health Index flowchart.

Table 72. Station reactors parameter #1: age/condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	< 50 years old
B	3	50-74 years old
C	2	75-99 years old
D	1	100-149 years old
E	0	>=150 years old

Table 73. Station reactors parameter #2: expert feedback condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	Excellent
B	3	Very Good
C	2	Good
	N/A	Unknown

Table 74. Station reactors parameter #3: visual inspection condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	Excellent
B	3	Very Good
C	2	Good
	N/A	Unknown

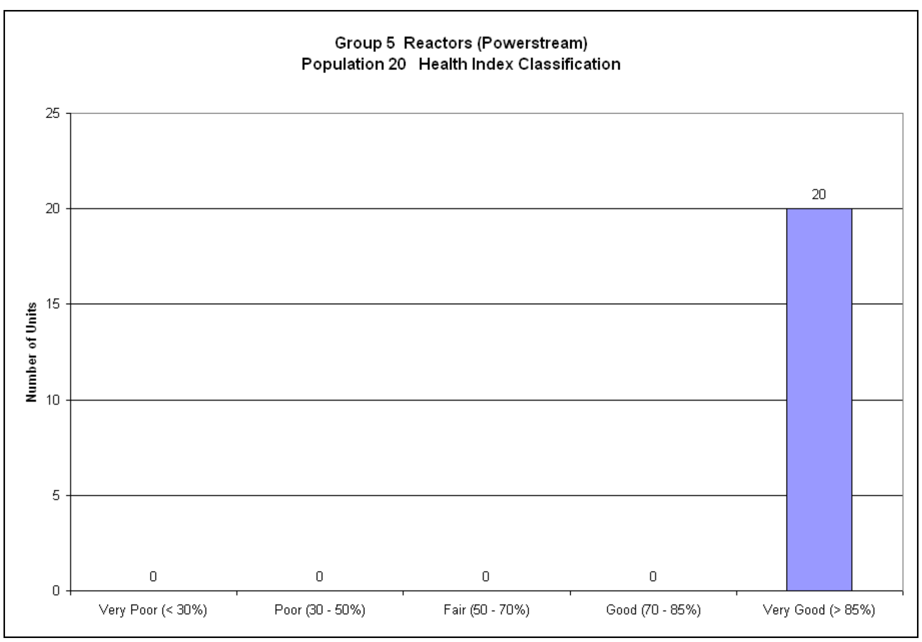

Figure 81. Station reactors Health Index histogram.

Failure Probability Curves

The station reactor failure probability (hazard rate) curve is based on a normal curve with a mean life equal to 75 years.

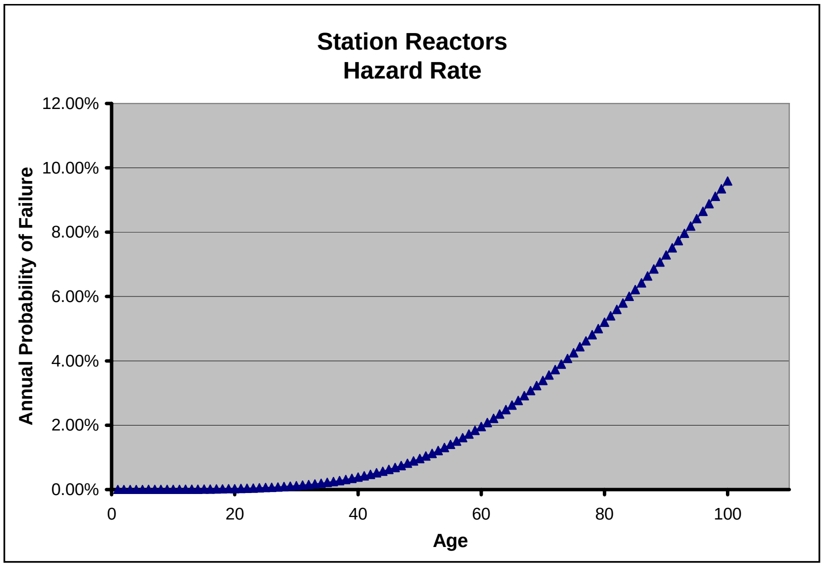

Figure 82. Station reactors hazard rate curve.

Failure Effects

The dominant failure mode assessed for station reactors is catastrophic failure requiring replacement. As provided by PowerStream, loss of a station reactor, on load will be lost as the remaining transformer will be able to carry the load of the companion transformer, there may be a momentary outage.

Intervention Mode

The intervention mode modeled for station reactors is replacement in-kind. The replacement costs were provided by PowerStream.

Replacement Program Results

The economic model projects the optimal intervention timing for each asset analyzed. The program charts are generated by combining the optimal intervention timings and the associated capital costs. The replacement program chart (Figure 83) shows results for transformers with complete demographic data (i.e., type and size).

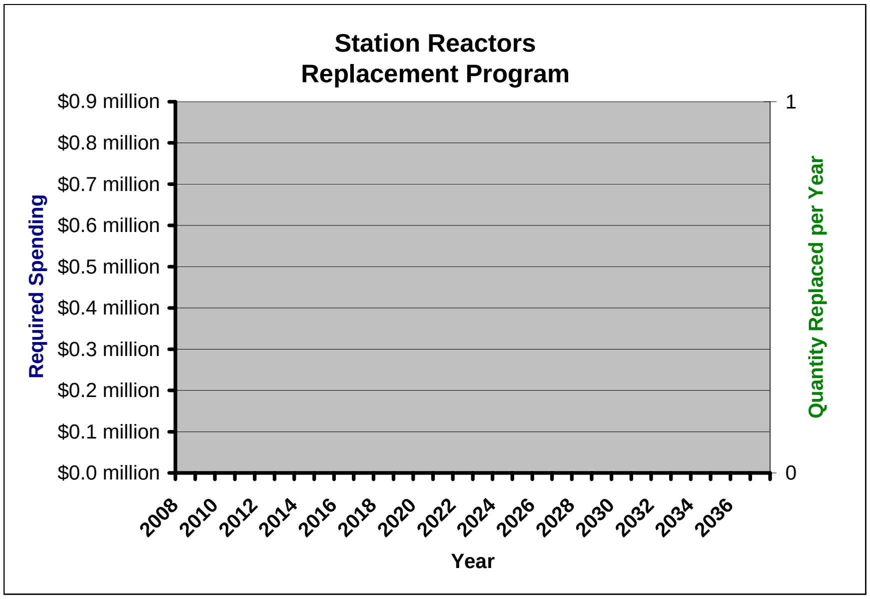

Figure 83. Station reactors replacement program.

The projected failures (Figure 84) account for system-wide annual failures. The replacement risk is an estimate of the reactive replacement spending associated with the projected failures.

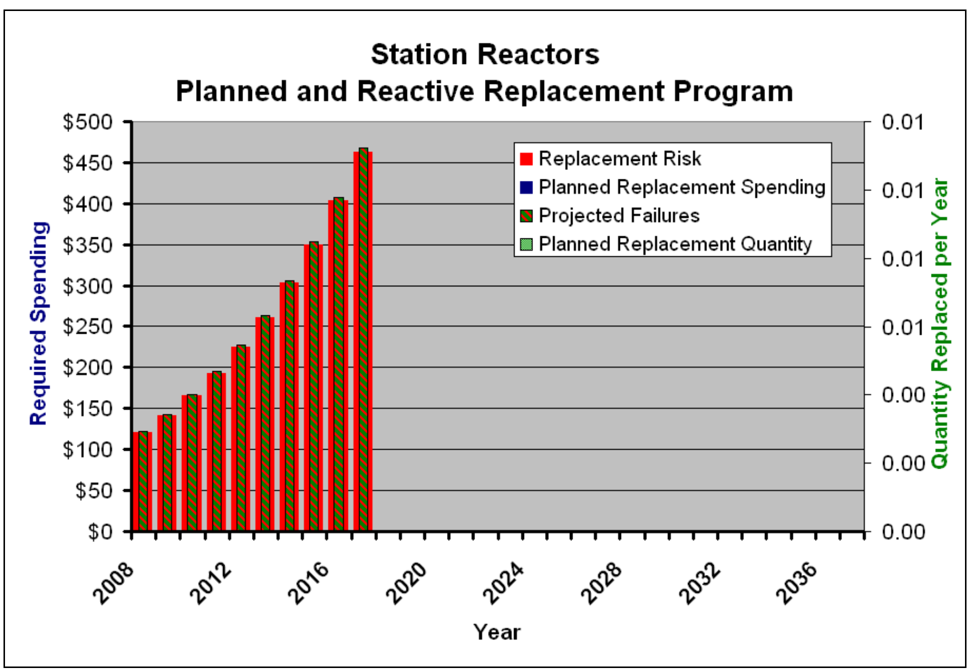

Figure 84. Station reactors planned and reactive program.

<u>Conclusions</u>

- Recommendations:
    - No risk-based planned replacement program is recommended for station reactors.
    - Continue capturing condition data per health index formulation and update the model. This should be an ongoing process of updating and re-running to generate annual budgets.
    - Consider capturing station reactor condition and age at failure to support customized failure probability curves and health index correlations.
    - Consider full life-cycle cost, including risk cost, when purchasing new transformers.
- Gaps:
    - None.

Wood Poles – Asset Class Details and Results

Summary of Asset Class
Wood poles are moderately complex assets with a low price per unit.

Wood pole failures are very rare due to aggressive replacement programs. Wood pole testing contractors make replacement recommendations based on test results and minimum physical life remaining. Program recommendations are based on statistical projections of physical life expectancy.

Health index formulation is based on industry best-practice.

Data Sources Available
General demographic and condition data acquired during wood pole test program.

Demographics
Number of units: 34,407
Typical life expectancy (years): 75
Estimated replacement cost: $10,000

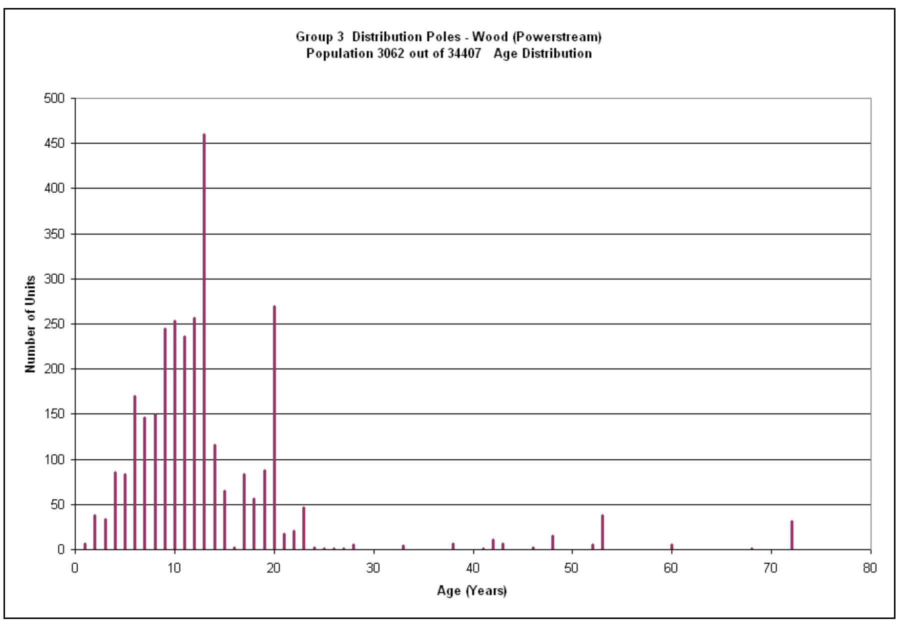

Figure 85. Wood poles installation history.

Asset Degradation

Overhead distribution lines consist of electrical conductors supported on insulators and mechanical structures. The support structure is usually a single wood or concrete pole. At locations with high mechanical loading, such as dead ends, angles and corners, the poles will be supported by guy wires attached to anchors installed in the ground.

Wood poles are the most common form of support for medium voltage overhead circuits as well as sub-transmission lines, however concrete poles are also used extensively especially in urban areas.

Distribution line design dictates usage of the poles varying in height and strength, depending upon the number and size of conductors, the average length of adjacent spans, maximum loadings, line angles, appropriate loading factors and the mass of installed equipment. Poles are categorized into classes (1 to 7), which reflect the relative strength of the pole. Stronger poles (lower numbered classes) are used for supporting equipment and handling stresses associated with corner structures and directional changes in the line. The height of a pole is determined by a number of factors, such as the number of conductors it must support, equipment-mounting requirements, clearances below the conductors for roads and the presence of coaxial cable or other telecommunications facilities.

As wood is a natural material the degradation processes are somewhat different to those which affect other physical assets on electricity distribution systems. The critical processes are biological involving naturally occurring fungi that attack and degrade wood, resulting in decay. The nature and severity of the degradation depends both on the type of wood and the environment. Some fungi attack the external surfaces of the pole and some the internal heartwood. Therefore, the mode of degradation can be split into either external rot or internal rot.

To prevent attack and decay of wood poles they are treated with preservatives prior to being installed. The preservatives have two functions, firstly to keep out moisture that is necessary to support the attacking fungus, and secondly as a biocide to kill off the fungus spores. Over the period of wood pole use in the electricity industry, the nature of the preservatives used has changed, as the chemicals previously used have become unacceptable from an environmental viewpoint. Nevertheless, effective and acceptable preservatives are available and poles well treated prior to installation have a long life (typically in excess of 50 years) prior to decay resulting in significant damage.

As a structural item the sole concern when assessing the condition for a wood pole is the reduction in mechanical strength due to degradation or damage. A particular problem when assessing wood poles is the potentially large variation in their original mechanical properties. Depending on the species, the mechanical strength of a new wood pole can vary greatly. Typically the first standard deviation has a width of ±15% for poles nominally in the same class. However in some test programs the minimum measured strength has been as low as 50% of the average.

The condition of the concrete poles is assessed by taking into consideration reduction in strength due to spalling or mechanical damage caused by vehicular collisions. Condition assessment of concrete poles can, similarly, be carried out through visual inspections and taking into account the extent of surface deterioration of the pole. There are many factors considered by utilities when establishing condition of poles. These include types of wood, historic rates of decay and average lifetimes, environment, perceived effectiveness of available techniques and cost. However, perhaps the most significant is the policy of routine line inspections. A foot patrol of overhead lines undertaken on a regular cycle is extremely effective in addressing the safety and security obligations.

The following criteria can be used in establishing health and condition of poles:

- Pole strength (through lab testing on selected samples)
- Existence of cracks for both wood and concrete poles
- Woodpecker or insect caused damage for wood poles
- Wood rot or concrete spalling
- Damage due to fire or mechanical damage
- Condition of guy wires
- Pole plumbness

The life expectancy of wood poles or concrete poles ranges from 30 to 50 years. Consequences of an in-service pole failure are quite serious, as they could lead to a serious accident involving the public. Depending on the number of circuits supported, a pole failure may also lead to a power interruption for significant number of customers.

Health Index Formulation and Results

The following charts provide the main condition parameters that were used in the PowerStream asset condition assessment and the weights assigned to each. Details of the Health Index formulation are provided in the tables.

Table 75. Wood poles Health Index parameters and weights

#	Wood Pole Condition Parameters	Weight
1	Age	3
2	Pole Strength	2
3	Maintenance Done? (Yes/No)	*

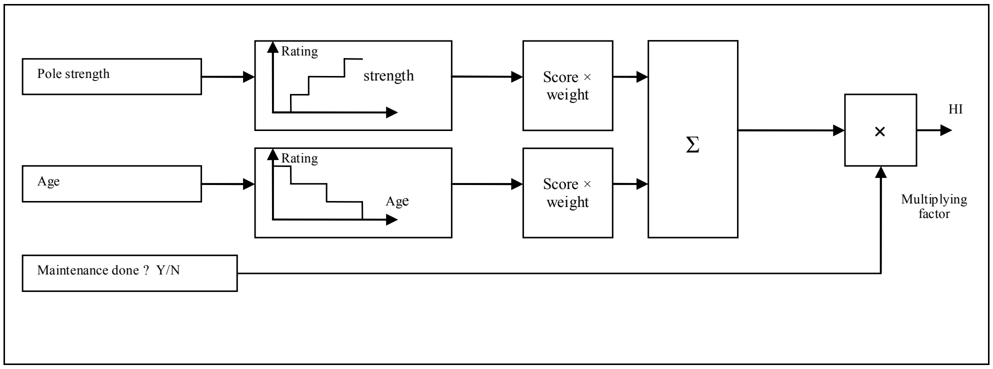

Figure 86. Wood poles Health Index flowchart.

Table 76. Wood poles parameter #1: age/condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	0-19 years old
B	3	20-39 years old
C	2	40-49 years old
D	1	50 years old
E	0	>=51 years old

Table 77. Wood poles parameter #2: distribution pole strength condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	95
B	3	87
C	2	50
D	1	33
E	0	0

Table 78. Wood poles parameter #3: distribution pole maintenance condition criteria

Multiplying Factor	Condition Criteria Description
0.8	Maintenance has been done
1	No maintenance work record

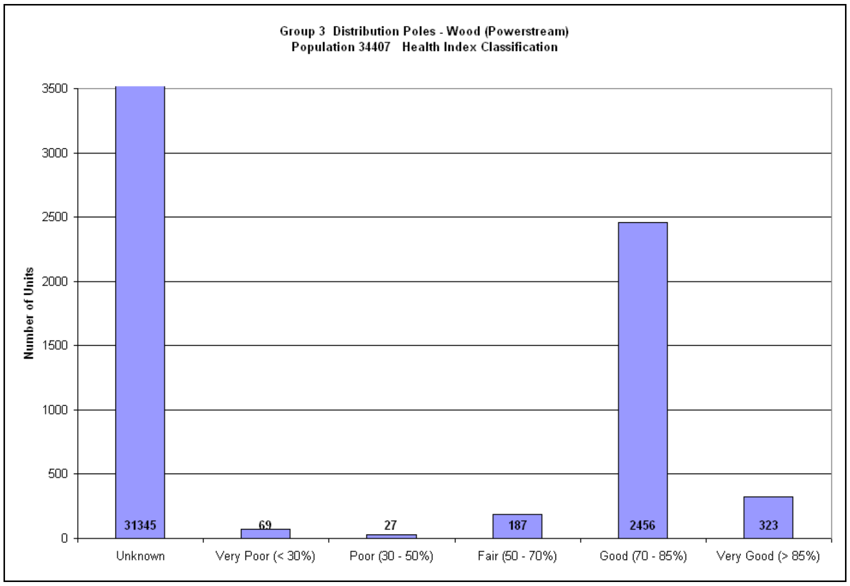

Figure 87. Wood poles Health Index histogram.

Failure Effects

The dominant failure mode assessed for wood poles is catastrophic failure requiring replacement.

Intervention Mode

Wood poles are replaced based on pole testing contractor recommendations and health index results. Risk-based analyses are not used to justify pole replacements.

Replacement Program Results

The long-range replacement program is based on contractor recommendations. Pole inspection and recommendations were analyzed to develop a correlation between age and failure.

Failure Probability Curves

Using the 3,031 poles inspected, failure curves were fit to the "Replace Now" and "3 Years" contractor recommendations.

A Maximum Likelihood Estimator (MLE) curve fitting method was utilized to develop the failure curves. The MLE method finds the most likely curve for a set of data by maximizing the likelihood function, which defines the probability of the observed scenario playing out. The MLE is preferable to other regression or curve-fitting methods since it accounts for suspended data points (the poles that have yet to fail). There is, however, insufficient demographic data to apply the failure curves to the remainder of wood pole population. The sample size is not considered representative of the larger population.

Confidence bounds were also calculated to indicate the reasonableness of the curve fits. The confidence bounds provide ranges within which failure curve values are likely to occur a certain percentage of the time. This helps gauge the utility of the data and the accuracy of the resulting estimates. The Likelihood Ratio Confidence Bounds were utilized to determine the 95 percent confidence level on the upper bounds of the Weibull parameters. The confidence bounds were calculated to determine the most aggressive hazard rate for the wood pole failure curves.

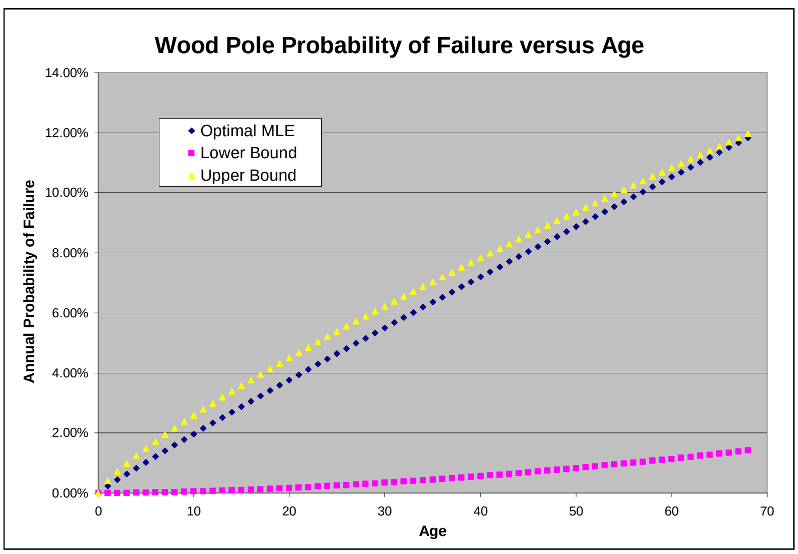

Figure 88. "Replace Now" failure curve.

The "Replace Now" failure curve (Figure 88) shows the optimal failure curve for the "Replace Now" recommendations, including the upper and lower confidence bounds based on a 95 percent confidence interval. The Weibull curve parameters are: Shape = 1.94, Scale = 32.57.

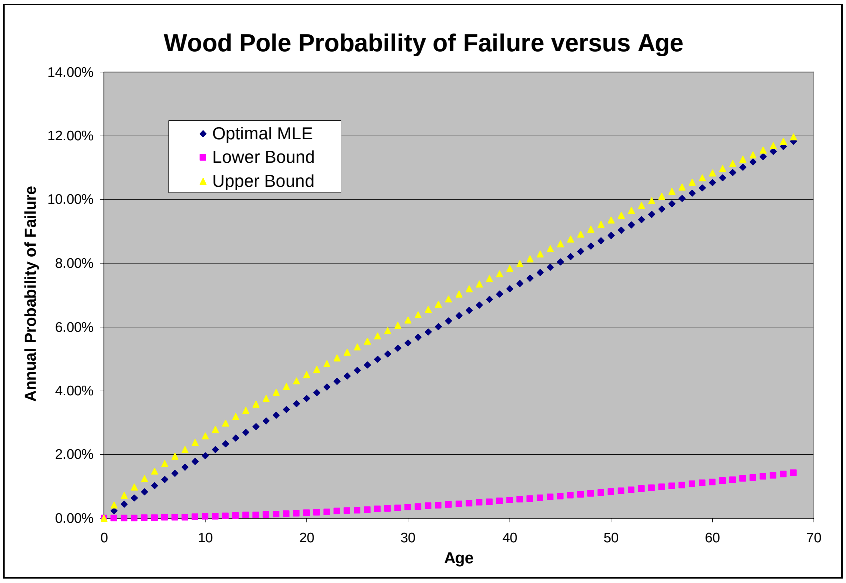

Figure 89. "Replace Now" contour plot.

The "Replace Now" contour plot (Figure 89) indicates the parameters meeting the 95 percent confidence level.

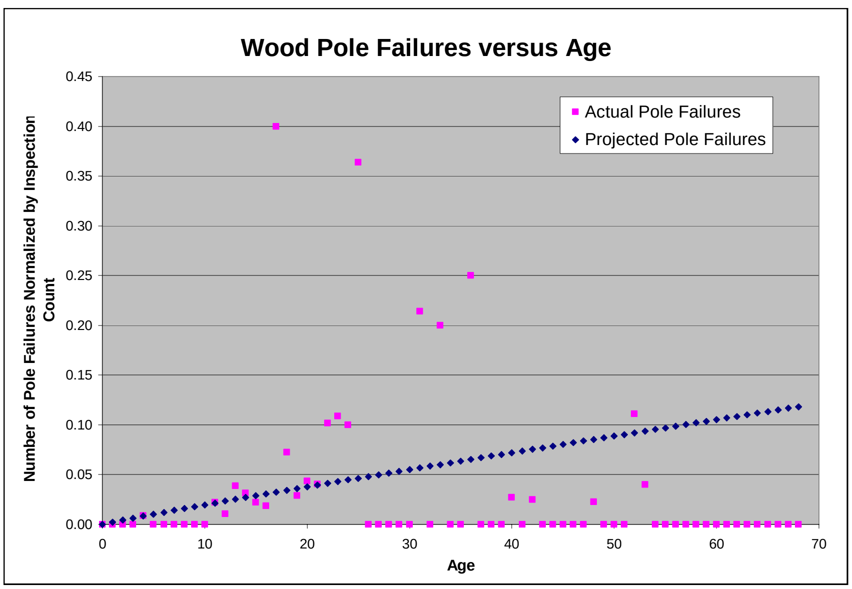

Figure 90. "Replace Now" pole failures.

The "Replace Now" pole failures chart (Figure 90) shows the optimal failure curve and actual pole failures normalized to the inspection count.

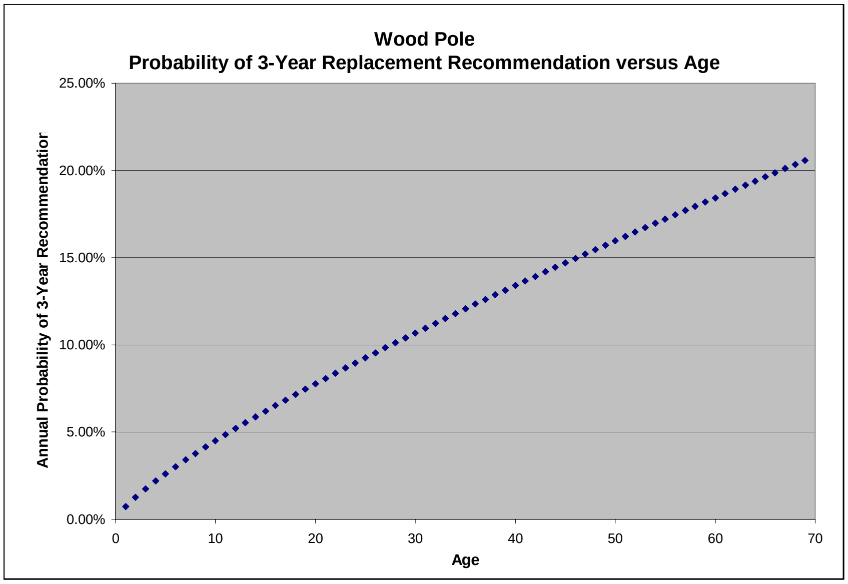

Figure 91. "3 Years" recommendation failure curve.

The poles identified by the contractor to be replaced in 3 years were also analyzed to develop a correlation with age. The failure curve shown in Figure 1Figure 91 has Weibull curve parameters: Shape = 1.79, Scale = 21.62.

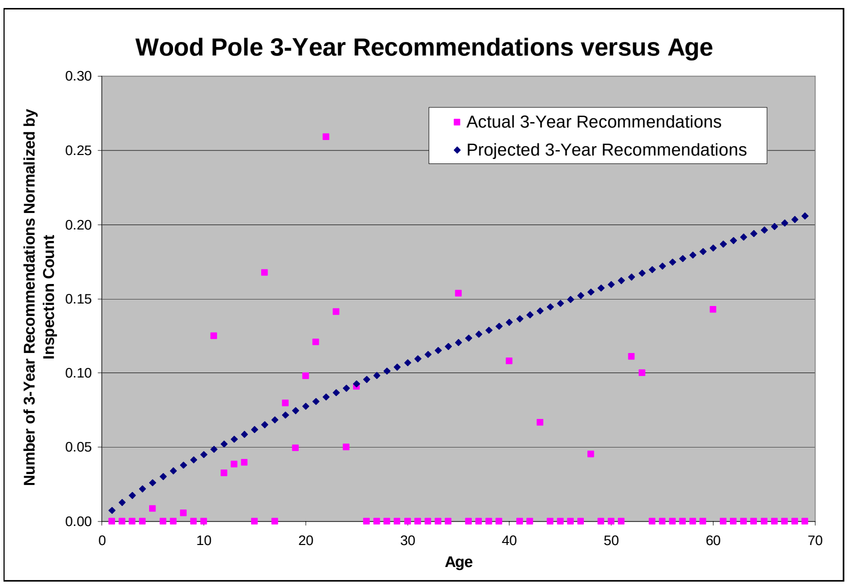

Figure 92. "3 Years" pole failures.

The "3 Years" pole failures chart (Figure 92) shows the optimal failure curve and actual 3-year replacement recommendations normalized to the inspection count.

Conclusions

- Recommendations:
  - Continue collecting inspection and failure data and updated customized wood pole failure curves.
  - Capture representative wood pole demographics samplings and extrapolate failures for wood pole population using "Replace Now" and "3 Years" curves.
  - Continue capturing condition data per health index formulation and update the model. This should be an ongoing process of updating and re-running to generate annual budgets.
- Gaps:
  - Remaining wood pole demographics and contractor recommendations.

Schedule VECC25-1: Net Fixed Assets - Continuity Schedule - (000's) - Display addtions separate from depreciation

Asset Group	2006 Board Approved (1)	2005 & 2006					2007					2008					2009				
		Additions	Depreciation	Additions net of Dep'n	Retirements / FMV Removal (2)	Ending Balance	Additions	Depreciation	Additions net of Dep'n	Retirements / FMV Removal (2)	Ending Balance	Additions	Depreciation	Additions net of Dep'n	Retirements / FMV Removal (2)	Ending Balance	Additions	Depreciation	Retirements / FMV Removal (2)	Retirements / FMV Removal	Ending Balance
Land and Buildings	3,798	6,644	85	6,559	(488)	9,869	275	76	199	(18)	10,049	0	76	(76)	0	9,973	3,500	76	3,424	0	13,397
TS Primary Above 50	55,298	9,570	4,526	5,044	0	60,342	5,670	2,245	3,425	0	63,767	1,837	2,339	(502)	0	63,265	14,452	2,543	11,909	0	75,174
DS	3,321	2,073	483	1,590	(141)	4,770	1,295	234	1,061	0	5,831	884	270	614	0	6,444	34	285	(251)	0	6,193
Poles, Wires	242,717	57,083	39,575	17,508	363	260,588	31,449	18,938	12,511	(3,003)	270,096	42,086	19,902	22,184	0	292,280	65,315	21,590	43,725	0	336,005
Line Transformers	90,854	22,441	14,771	7,670	(75)	98,449	9,215	7,288	1,927	0	100,376	9,817	7,502	2,315	0	102,690	14,365	7,811	6,554	0	109,243
Services and Meters	37,888	15,601	6,312	9,289	(241)	46,936	16,385	3,508	12,877	0	59,813	4,246	4,045	201	0	60,014	3,731	4,205	(474)	0	59,540
General Plant	817	1,809	415	1,394	(135)	2,076	(334)	175	(509)	154	1,720	23,119	403	22,716	0	24,435	0	635	(635)	0	23,801
Equipment	5,580	1,751	1,038	713	(127)	6,166	2,619	1,455	1,164	(716)	6,614	5,191	1,801	3,390	(537)	9,467	2,063	2,091	(28)	(537)	8,903
IT Assets	1,682	5,795	2,181	3,614	16	5,312	4,291	2,743	1,548	0	6,860	6,068	4,274	1,794	0	8,655	3,925	5,744	(1,819)	0	6,836
CDM Assets	1,620	(1,620)	0	(1,620)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Distribution Assets	5,803	618	603	15	129	5,948	526	729	(203)	0	5,745	1,093	783	310	0	6,054	288	829	(541)	0	5,514
Contributions and Grants	(79,108)	(48,639)	(3,206)	(45,433)	(6,663)	(131,202)	(9,527)	(6,393)	(3,134)	(15)	(134,352)	(20,865)	(7,001)	(13,864)	0	(148,217)	(21,189)	(7,842)	(13,347)	0	(161,564)
TOTAL	370,270	73,126	66,783	6,343	(7,362)	369,254	61,864	30,998	30,866	(3,598)	396,519	73,476	34,394	39,082	(537)	435,060	86,484	37,967	48,517	(537)	483,042
			control chk	ok					ok					ok					ok		

(1) Harmonzed rate application (EB-2007-0074), EDR 2006 Model, Sheet 2-4 Adjusted Accounting Data
(2) Fair market value("FMV") increment recorded on purchase of Aurora Hydro has been removed for rate filing
Above data copied from primary fixed asset fty file and "NFA…." tab

VECC IR #28
Throughput Revenue - details

Schedule VECC 28-1

	2009 Distribution Revenue												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	**2009**
Residential	$4,810,608	$4,764,485	$4,786,875	$4,668,848	$4,656,225	$4,895,579	$5,100,409	$4,978,186	$4,766,830	$4,703,804	$4,749,720	$4,829,849	**$57,711,418**
GS Less Than 50 kW	$1,434,940	$1,418,276	$1,425,093	$1,383,785	$1,378,602	$1,459,782	$1,529,129	$1,486,382	$1,413,085	$1,390,628	$1,405,508	$1,432,116	**$17,157,326**
GS 50 to 4,999 kW	$3,098,902	$3,055,758	$3,072,272	$2,966,517	$2,979,342	$3,187,757	$3,365,667	$3,254,602	$3,064,781	$3,006,020	$3,043,518	$3,111,246	**$37,206,382**
GS 50 to 4,999 kW Legacy	$18,257	$17,980	$18,060	$17,407	$0	$0	$0	$0	$0	$0	$0	$0	**$71,704**
Large Use	$17,403	$17,202	$17,260	$16,787	$16,712	$17,591	$18,339	$17,850	$17,024	$16,759	$16,906	$17,183	**$207,016**
Unmetered Scattered Load	$37,754	$37,641	$37,766	$37,405	$37,408	$38,285	$39,042	$38,666	$37,981	$37,810	$38,016	$38,342	**$456,116**
Sentinel Lighting	$1,178	$1,157	$1,163	$1,113	$1,105	$1,198	$1,278	$1,226	$1,138	$1,110	$1,126	$1,155	**$13,949**
Street Lighting	$89,111	$88,423	$88,859	$86,992	$86,854	$90,849	$94,278	$92,342	$88,944	$87,980	$88,802	$90,185	**$1,073,619**
TOTALS	**$9,508,153**	**$9,400,922**	**$9,447,349**	**$9,178,853**	**$9,156,249**	**$9,691,042**	**$10,148,142**	**$9,869,254**	**$9,389,784**	**$9,244,111**	**$9,343,596**	**$9,520,075**	**$113,897,531**

		Variable charges												
	Rate	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	**2009**
		P08	*P08*	*P08*	*P08*	*P08*	*P08*	*P08*	*P08*	*P08*	*P08*	*P08*	*P08*	
Residential	$ 0.0129	$2,227,045	$2,173,888	$2,189,244	$2,064,183	$2,044,526	$2,276,846	$2,474,641	$2,345,384	$2,126,994	$2,056,934	$2,095,816	$2,168,911	**$26,244,413**
GS Less Than 50 kW	$ 0.0112	$763,298	$745,079	$750,342	$707,479	$700,741	$780,367	$848,159	$803,858	$729,007	$704,994	$718,320	$743,373	**$8,995,017**
GS 50 to 4,999 kW	$ 2.2713	$1,939,228	$1,892,941	$1,906,312	$1,797,414	$1,806,492	$2,011,764	$2,186,531	$2,072,323	$1,879,359	$1,817,456	$1,851,810	$1,916,395	**$23,078,026**
GS 50 to 4,999 kW Legacy	$ 1.5576	$11,631	$11,353	$11,434	$10,780	$0	$0	$0	$0	$0	$0	$0	$0	**$45,198**
Large Use	$ 1.1989	$8,425	$8,224	$8,282	$7,809	$7,734	$8,613	$9,361	$8,872	$8,046	$7,781	$7,928	$8,205	**$99,279**
Unmetered Scattered Load	$ 0.0111	$7,719	$7,535	$7,588	$7,155	$7,087	$7,892	$8,577	$8,129	$7,372	$7,130	$7,264	$7,518	**$90,966**
Sentinel Lighting	$ 6.0151	$893	$872	$878	$828	$820	$913	$992	$940	$853	$825	$840	$870	**$10,524**
Street Lighting	$ 3.3980	$36,529	$35,657	$35,909	$33,857	$33,535	$37,345	$40,590	$38,470	$34,888	$33,738	$34,376	$35,575	**$430,468**
TOTALS		**$4,994,767**	**$4,875,549**	**$4,909,987**	**$4,629,504**	**$4,600,935**	**$5,123,740**	**$5,568,853**	**$5,277,977**	**$4,786,519**	**$4,628,858**	**$4,716,356**	**$4,880,847**	**$58,993,892**

		Fixed Charges												
	Rate	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	**2009**
		P08	*P08*	*P08*	*P08*	*P08*	*P08*	*P08*	*P08*	*P08*	*P08*	*P08*	*P08*	
Residential	$ 12.02	$2,583,563	$2,590,597	$2,597,631	$2,604,665	$2,611,699	$2,618,733	$2,625,767	$2,632,802	$2,639,836	$2,646,870	$2,653,904	$2,660,938	**$31,467,004**
GS Less Than 50 kW	$ 28.70	$671,642	$673,197	$674,751	$676,306	$677,861	$679,415	$680,970	$682,524	$684,079	$685,633	$687,188	$688,743	**$8,162,309**
GS 50 to 4,999 kW	$ 301.73	$1,159,674	$1,162,817	$1,165,960	$1,169,103	$1,172,850	$1,175,993	$1,179,136	$1,182,279	$1,185,422	$1,188,565	$1,191,708	$1,194,851	**$14,128,356**
GS 50 to 4,999 kW Legacy	$ 3,313.25	$6,627	$6,627	$6,627	$6,627	$0	$0	$0	$0	$0	$0	$0	$0	**$26,506**
Large Use	$ 8,978.09	$8,978	$8,978	$8,978	$8,978	$8,978	$8,978	$8,978	$8,978	$8,978	$8,978	$8,978	$8,978	**$107,737**
Unmetered Scattered Load	$ 14.35	$30,035	$30,106	$30,178	$30,250	$30,322	$30,393	$30,465	$30,537	$30,609	$30,680	$30,752	$30,824	**$365,150**
Sentinel Lighting	$ 2.01	$285	$285	$285	$285	$285	$285	$285	$285	$285	$285	$285	$285	**$3,425**
Street Lighting	$ 0.84	$52,582	$52,766	$52,951	$53,135	$53,319	$53,504	$53,688	$53,872	$54,057	$54,241	$54,425	$54,610	**$643,152**
TOTALS		**4,513,386**	**4,525,374**	**4,537,361**	**4,549,349**	**4,555,314**	**4,567,302**	**4,579,289**	**4,591,277**	**4,603,265**	**4,615,253**	**4,627,241**	**4,639,228**	**54,903,639**

	2009 Customer count												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	**2009**
Residential	214,939	215,524	216,109	216,694	217,279	217,865	218,450	219,035	219,620	220,205	220,791	221,376	**218,157**
GS Less Than 50 kW	23,402	23,456	23,511	23,565	23,619	23,673	23,727	23,781	23,836	23,890	23,944	23,998	**23,700**
GS 50 to 4,999 kW	3,843	3,854	3,864	3,875	3,887	3,898	3,908	3,918	3,929	3,939	3,950	3,960	**3,902**
GS 50 to 4,999 kW Legacy	2	2	2	2	-	-	-	-	-	-	-	-	**1**
Large Use	1	1	1	1	1	1	1	1	1	1	1	1	**1**
Unmetered Scattered Load	2,093	2,098	2,103	2,108	2,113	2,118	2,123	2,128	2,133	2,138	2,143	2,148	**2,121**
Sentinel Lighting	142	142	142	142	142	142	142	142	142	142	142	142	**142**
Street Lighting	62,598	62,817	63,037	63,256	63,476	63,695	63,914	64,134	64,353	64,573	64,792	65,012	**63,805**
TOTALS	**307,020**	**307,894**	**308,768**	**309,643**	**310,517**	**311,391**	**312,265**	**313,140**	**314,014**	**314,888**	**315,762**	**316,637**	**311,828**
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VECC IR #28

Schedule VECC 28-1

		2009 Consumption, kwh												
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	**2009**
Residential	kWh	172,639,149	168,518,468	169,708,806	160,014,190	158,490,404	176,499,690	191,832,674	181,812,740	164,883,288	159,452,266	162,466,344	168,132,627	**2,034,450,648**
GS Less Than 50 kW	kWh	68,151,608	66,524,914	66,994,815	63,167,737	62,566,202	69,675,608	75,728,508	71,773,005	65,089,878	62,945,910	64,135,757	66,372,598	**803,126,540**
GS 50 to 4,999 kW	kW	326,907,500	319,104,625	321,358,634	303,001,023	304,531,410	339,135,356	368,596,921	349,344,117	316,815,018	306,379,581	312,170,982	323,058,462	**3,890,403,631**
GS 50 to 4,999 kW Legacy	kW	4,810,020	4,695,211	4,728,376	4,458,267	-	-	-	-	-	-	-	-	**18,691,873**
Large Use	kW	2,665,794	2,602,165	2,620,546	2,470,847	2,447,317	2,725,406	2,962,170	2,807,447	2,546,033	2,462,170	2,508,712	2,596,207	**31,414,814**
Unmetered Scattered Load	kWh	695,425	678,826	683,621	644,569	638,431	710,976	772,740	732,378	664,182	642,305	654,447	677,271	**8,195,169**
Sentinel Lighting	kW	57,952	56,569	56,968	53,714	53,203	59,248	64,395	61,031	55,349	53,525	54,537	56,439	**682,931**
Street Lighting	kW	3,593,027	3,507,266	3,532,040	3,330,272	3,298,558	3,673,374	3,992,489	3,783,951	3,431,609	3,318,577	3,381,307	3,499,236	**42,341,705**
TOTALS		**579,520,475**	**565,688,044**	**569,683,805**	**537,140,619**	**532,025,524**	**592,479,658**	**643,949,897**	**610,314,670**	**553,485,357**	**535,254,335**	**545,372,086**	**564,392,840**	**6,829,307,310**
														-

		2009 Load, kw												
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	**2009**
Residential	kWh	-	-	-	-	-	-	-	-	-	-	-	-	**-**
GS Less Than 50 kW	kWh	-	-	-	-	-	-	-	-	-	-	-	-	**-**
GS 50 to 4,999 kW	kW	853,797	833,417	839,304	791,359	795,356	885,732	962,678	912,395	827,438	800,183	815,309	843,744	**10,160,712**
GS 50 to 4,999 kW Legacy	kW	7,467	7,289	7,340	6,921	-	-	-	-	-	-	-	-	**29,018**
Large Use	kW	7,027	6,859	6,908	6,513	6,451	7,184	7,808	7,400	6,711	6,490	6,613	6,844	**82,809**
Unmetered Scattered Load	kWh	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Sentinel Lighting	kW	148	145	146	138	136	152	165	156	142	137	140	145	**1,750**
Street Lighting	kW	10,750	10,493	10,568	9,964	9,869	10,990	11,945	11,321	10,267	9,929	10,117	10,469	**126,683**
TOTALS		**879,189**	**858,204**	**864,266**	**814,895**	**811,812**	**904,059**	**982,597**	**931,273**	**844,558**	**816,739**	**832,178**	**861,201**	**10,400,971**
														-

Provincial Economic Outlook

BMO Capital Markets Economics
December 19, 2008

Real GDP Growth (% change, chain-weighted)

	Cda	BC	Alta	Sask	Man	Ont	Que	NB	NS	PEI	Nfld
2006	**3.1**	4.4	6.1	-0.3	4.0	2.6	1.7	2.4	0.9	2.4	3.0
2007	**2.7**	3.0	3.1	2.5	3.3	2.3	2.6	1.7	1.7	2.4	9.1
2008 f	**0.7**	1.4	1.9	3.0	1.7	-0.2	0.2	1.0	1.1	0.8	1.3
2009 f	**-1.3**	0.0	-0.7	1.0	-0.4	-2.3	-1.0	0.3	-0.1	0.2	0.7
2010 f	**2.0**	2.0	2.1	1.6	1.8	2.2	1.9	1.9	1.6	1.2	2.0

Employment Growth (% change)

	Cda	BC	Alta	Sask	Man	Ont	Que	NB	NS	PEI	Nfld
2006	**1.9**	3.0	4.8	1.7	1.2	1.5	1.3	1.4	-0.3	0.5	0.7
2007	**2.3**	3.2	4.7	2.1	1.6	1.5	2.3	2.1	1.3	1.2	0.7
2008 f	**1.6**	2.4	2.7	1.7	1.8	1.5	0.7	0.9	1.2	1.5	1.7
2009 f	**-0.8**	0.2	0.6	1.0	0.3	-1.9	-1.0	0.5	0.4	0.6	1.0
2010 f	**0.5**	0.5	0.8	1.0	0.4	0.5	0.3	0.5	0.4	0.7	2.1

Unemployment Rate (percent)

	Cda	BC	Alta	Sask	Man	Ont	Que	NB	NS	PEI	Nfld
2006	**6.3**	4.8	3.4	4.6	4.3	6.3	8.0	8.7	7.9	11.1	14.8
2007	**6.0**	4.2	3.5	4.2	4.4	6.4	7.2	7.6	8.1	10.3	13.6
2008 f	**6.1**	4.3	3.6	4.2	4.1	6.4	7.4	8.5	7.7	10.7	13.0
2009 f	**7.4**	6.0	4.7	4.5	4.9	8.2	8.0	9.6	8.4	11.0	12.6
2010 f	**7.8**	7.3	5.6	5.0	5.6	8.5	8.2	10.5	9.1	11.2	11.9

Housing Starts (thousands)

	Cda	BC	Alta	Sask	Man	Ont	Que	NB	NS	PEI	Nfld
2006	**229.1**	36.6	49.1	3.7	5.0	74.4	48.0	4.0	5.2	0.8	2.3
2007	**227.6**	39.2	48.1	5.9	5.8	68.0	48.5	4.1	4.7	0.7	2.6
2008 f	**213.8**	35.5	30.3	7.0	5.6	75.7	47.1	4.4	4.5	0.7	3.0
2009 f	**175.0**	29.0	26.0	6.3	4.8	60.0	38.5	3.4	3.3	0.6	3.2
2010 f	**170.0**	26.8	30.0	5.0	4.5	57.0	37.0	3.5	3.0	0.6	2.7

Consumer Price Index (% change)

	Cda	BC	Alta	Sask	Man	Ont	Que	NB	NS	PEI	Nfld
2006	**2.0**	1.7	3.9	2.0	1.9	1.8	1.7	1.7	2.1	2.2	1.8
2007	**2.1**	1.8	4.9	2.9	2.1	1.8	1.7	1.9	1.9	1.8	1.6
2008 f	**2.6**	2.2	3.6	3.4	2.3	2.3	2.4	2.2	3.5	3.6	3.1
2009 f	**0.8**	0.9	1.2	2.1	1.0	0.7	0.8	0.7	0.6	0.7	1.6
2010 f	**1.8**	1.9	2.0	1.7	1.5	1.8	1.7	1.8	1.7	1.8	2.0

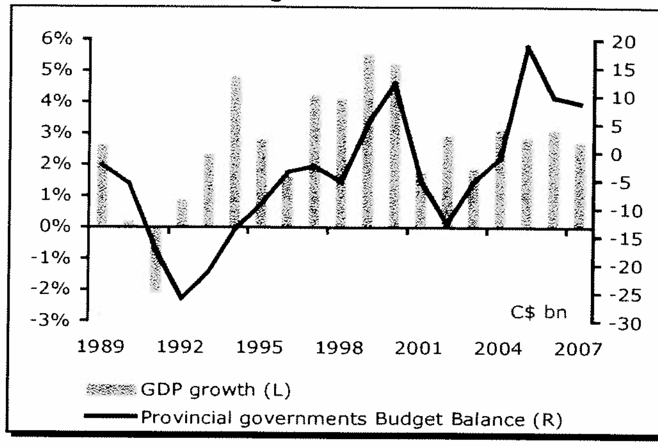
Table 2

Federal Transfers by Province (2008/09)

Billion C$	Transfers	% of Revenue
BC	5.8	15
Alta	3.8	10
Sask	1.4	15
Man	3.9	32
Ont	16.5	17
Qué	14.1	22
NB	2.4	33
NS	2.9	36
PEI	0.6	41
N&L	1.6	25

Chart 2

Recessions See Huge Fiscal Deterioration



policy effectiveness hampered by the worldwide strains on credit availability and wide spreads, fiscal policy might well be the only effective tool to boost growth during the current shock to Canada's export prospects.

Sharing the Pain

Virtually no corner of the country will fully escape the impact of the US recession and the accompanying slowdown in global economic performance. Reflecting the darkening picture for economies beyond Canada's shores, and new fragilities in financial markets, our current forecasts for GDP, employment and CPI (Table 3) all represent significant markdowns from our June outlook, when the national picture looked destined for growth of more than 2% in 2009. What once looked like a painful outcome for regions linked to manufacturing will now, to some extent, be shared by a broader geographic and industrial mix across the country.

For Ontario, a challenging economic climate will be nothing new at this point. Canada's largest province has been struggling to deal with multiple disadvantages relating to some other regions of the country. Its heavy weight in manufacturing that is sensitive to a strong Canadian dollar and global competition, its status of an importer of oil, and the absence of equalization increases that other provinces enjoyed, were all reasons to expect the worst for the province as the year began.

It's remarkable, then, that the province's economy has managed to see only a modest decline since the start of Q4 2007, rather than falling into a deeper abyss. Indeed, year to date, Ontario has actually outperformed the national average in terms of growth in retail sales and housing starts (Table 4). Provincial tax cuts, alongside Ottawa's GST cut, helped consumers weather the storm and continue to shop, while construction and government provided an important offset for job creation.

But with all three of the province's economic engines—manufacturing, financial services, and housing—now sputtering, output declines are expected in both Q4 of

Table 3

Provincial Forecast	Real GDP (year-over-year change, %)			CPI (year-over-year change, %)			Unemployment Rate (annual average, %)		
	07A	08F	09F	07A	08F	09F	07A	08F	09F
British Columbia	3.0	1.5	1.5	1.7	2.1	2.3	4.2	4.3	5.2
Alberta	3.1	1.3	1.9	4.9	3.7	2.2	3.5	3.6	4.0
Saskatchewan	2.5	3.0	2.4	2.9	3.4	2.5	4.2	4.3	4.4
Manitoba	3.3	2.0	1.4	2.1	2.3	1.7	4.4	4.1	4.5
Ontario	2.3	-0.1	0.1	1.8	2.0	1.8	6.4	6.4	7.2
Québec	2.6	0.4	0.4	1.6	2.2	1.9	7.2	7.5	8.0
New Brunswick	1.7	1.2	0.7	1.9	2.2	1.8	7.6	8.6	8.9
Nova Scotia	1.7	1.2	1.2	1.9	3.3	2.3	8.1	7.7	8.0
Prince Edward Island	2.4	0.7	0.7	1.8	3.5	2.0	10.3	10.5	11.1
Newfoundland & Labrador	9.1	0.7	0.7	1.4	2.9	2.1	13.6	13.1	13.5
Canada	**2.7**	**0.6**	**0.8**	**2.1**	**2.4**	**2.0**	**6.0**	**6.1**	**6.7**

Schedule VECC 31-1

Featuring Our 2010 Forecast

Global Economic Research

December 17, 2008

Provincial Forecast Update

	2000-07	2008f	2009f	2010f	2000-07	2008f	2009f	2010f
	Real GDP (annual % change)				Budget Balance, FY March 31* ($millions)			
Canada	**3.0**	**0.7**	**-1.2**	**1.9**	**10,799**	**9,597**	**-2,000**	**-13,500**
Newfoundland and Labrador	4.8	1.4	0.4	2.5	-347	1,377	1,266	n.a.
Prince Edward Island	2.1	0.6	-0.5	1.2	-28	-11	-49	n.a.
Nova Scotia	2.2	1.0	-0.2	1.9	15	419	355	n.a.
New Brunswick	2.2	1.0	-0.1	2.0	77	87	-285	n.a.
Quebec	2.2	0.5	-1.1	1.8	-144	0	0	n.a.
Ontario	2.7	-0.2	-2.0	1.6	-176	600	-500	n.a.
Manitoba	2.5	1.8	-0.2	1.8	n.a.	576	96	n.a.
Saskatchewan	1.9	3.0	0.6	2.4	153	641	2,318	n.a.
Alberta	4.2	1.7	-0.3	2.2	4,869	4,581	2,003	n.a.
British Columbia	3.2	1.5	-0.4	2.6	769	2,886	450	n.a.

* FY09 forecasts: provincial governments.

	Employment (annual % change)				Unemployment Rate (annual average, %)			
Canada	**2.0**	**1.6**	**-1.0**	**0.8**	**6.9**	**6.1**	**7.6**	**7.7**
Newfoundland and Labrador	1.0	1.7	0.2	1.3	15.7	13.1	13.7	13.6
Prince Edward Island	1.8	1.4	-0.3	0.5	11.3	10.7	11.4	11.4
Nova Scotia	1.3	1.3	-0.1	0.8	8.8	7.7	8.5	8.5
New Brunswick	1.4	1.0	-0.1	1.0	9.7	8.6	9.5	9.4
Quebec	1.8	0.8	-1.0	0.7	8.4	7.3	8.8	9.0
Ontario	2.0	1.5	-1.8	0.5	6.5	6.5	8.5	8.6
Manitoba	1.2	1.7	0.1	0.9	4.9	4.2	5.2	5.3
Saskatchewan	0.8	1.9	0.8	1.5	5.2	4.2	5.0	4.8
Alberta	3.0	2.8	-0.2	1.2	4.4	3.4	4.6	4.5
British Columbia	2.3	2.3	-0.3	1.5	6.7	4.5	5.6	5.4

	Housing Starts (annual, thousands of units)				Motor Vehicle Sales (annual, thousands of units)			
Canada	**207**	**214**	**170**	**175**	**1,600**	**1,660**	**1,475**	**1,530**
Atlantic	12	12	10	10	111	129	116	120
Quebec	44	48	41	41	402	428	375	390
Ontario	77	75	60	61	619	581	506	524
Manitoba	4	6	5	5	44	47	42	43
Saskatchewan	4	7	5	5	39	48	47	49
Alberta	38	30	22	25	204	245	220	228
British Columbia	28	36	27	28	181	182	169	176

Scotia Economics

Scotia Plaza 40 King Street West, 63rd Floor
Toronto, Ontario Canada M5H 1H1
Tel: (416) 866-6253 Fax: (416) 866-2829
Email: scotia_economics@scotiacapital.com

Provincial Forecast Update is available on: **www.scotiabank.com** and **Bloomberg at SCOE**

PROVINCIAL OUTLOOK

December 19, 2008

Forecast detail

Average annual % change unless otherwise indicated

	Real GDP				Employment				Unemployment rate %				Housing starts Thousands				Retail sales			
	07	08	09	10	07	08	09	10	07	08	09	10	07	08	09	10	07	08	09	10
N.& L.	9.1	0.0	-0.5	3.0	0.7	1.6	-0.2	1.2	13.6	13.2	13.2	13.1	2.6	3.0	2.9	3.0	9.0	8.6	3.5	3.9
P.E.I	2.4	1.5	0.5	2.0	1.1	1.4	-0.4	1.3	10.3	10.6	10.7	10.8	0.8	0.7	0.6	0.7	7.7	5.9	3.0	3.7
N.S.	1.7	1.2	0.8	2.5	1.3	1.3	0.1	1.4	8.0	7.7	8.5	8.5	4.8	4.4	3.2	3.5	4.2	6.0	3.5	3.9
N.B.	1.7	1.6	1.2	2.7	2.1	0.9	0.3	1.4	7.5	8.6	9.4	9.5	4.2	4.5	3.3	3.5	5.7	5.8	3.3	4.0
QUE.	2.6	0.6	0.0	2.3	2.3	0.8	-0.1	1.2	7.2	7.3	8.1	8.2	48.6	47.3	35.0	37.0	4.6	6.0	3.1	4.5
ONT.	2.3	-0.2	-1.4	2.5	1.6	1.5	-0.9	1.1	6.4	6.5	8.3	8.4	68.1	75.5	64.3	67.0	3.9	5.1	2.3	4.3
MAN.	3.3	2.5	1.9	2.8	1.6	1.7	0.8	1.7	4.4	4.1	4.8	5.1	5.7	5.7	5.2	5.3	8.8	7.7	3.4	5.1
SASK.	2.5	3.5	2.8	2.4	2.1	2.1	1.5	1.4	4.2	4.1	4.6	4.9	6.0	6.9	4.6	3.7	13.0	11.1	5.4	4.9
ALTA.	3.1	1.5	2.1	2.9	4.7	2.8	1.0	1.7	3.5	3.5	4.6	5.0	48.3	29.9	24.0	28.5	9.3	1.1	2.8	5.6
B.C.	3.0	0.8	0.6	3.5	3.2	2.2	0.2	2.5	4.2	4.5	5.6	5.4	39.2	35.0	23.5	26.0	6.7	2.2	3.0	6.8
CANADA	2.7	0.6	0.0	2.7	2.3	1.6	-0.1	1.4	6.0	6.1	7.3	7.4	228	213	166	178	5.8	4.7	2.9	4.9

Key provincial comparisons

2007 unless otherwise indicated

	NFLD	P.E.I.	N.S.	N.B.	QUE	ONT	MAN	SASK	ALTA	B.C.
Population (000s)	507	139	935	751	7,720	12,851	1,190	1,003	3,487	4,403
Gross domestic product ($ billions)	29.5	4.5	33.0	26.9	296.7	585.0	48.5	51.6	258.9	192.5
Real GDP ($2002 billions)	19.7	4.1	28.8	23.7	265.9	536.3	41.7	39.8	187.5	164.6
Share of Canada real GDP (%)	1.5	0.3	2.2	1.8	20.1	40.6	3.2	3.0	14.2	12.5
Real GDP growth (CAR, last five years 02-07, %)	3.7	2.3	1.2	2.3	1.9	2.3	2.6	3.0	4.5	3.6
Real GDP per capita ($)	38,825	29,943	30,827	31,579	34,553	41,934	35,151	40,008	54,187	37,629
Real GDP growth rate per capita (CAR, last five years 02-07, %)	4.2	2.1	1.2	2.3	1.3	1.2	2.1	3.0	2.3	2.3
Personal disposable income per capita ($)	24,924	22,466	24,365	23,690	24,473	27,743	25,157	25,378	35,349	26,833
Employment growth (CAR, last five years 02-07, %)	0.9	1.4	1.1	1.1	1.5	1.8	1.0	1.4	3.2	2.9
Employment rate (November 2008, %)	51.2	60.3	59.0	59.3	60.9	63.1	66.7	67.3	72.2	63.0
Discomfort index (inflation + unemp. Rates, latest)	17.3	14.3	11.4	10.2	10.0	8.8	6.9	8.0	6.0	6.9
Manufacturing industry output (% of real GDP)	4.6	11.8	9.8	12.7	18.9	18.3	12.9	7.2	9.3	10.6
Personal expenditures goods & services (% of real GDP)	54.0	70.4	70.3	67.5	63.3	58.8	63.3	58.4	50.3	68.6
International exports (% of real GDP)	39.6	31.5	25.3	43.8	36.3	45.8	31.9	40.1	35.9	28.6

Source: Statistics Canada, RBC Economics Research

REAL GROSS DOMESTIC PRODUCT (GDP)
Annual average per cent change

	82/91	2006	2007	2008E	2009F	2010F
CANADA	-2.5	2.8	2.7	0.7	-1.4	2.4
N. & L.	0.7	3.3	9.1	0.0	-1.0	1.2
P.E.I.	0.3	2.6	2.0	0.8	-0.7	1.3
N.S.	1.4	0.9	1.6	0.9	-0.5	1.7
N.B.	0.9	3.0	1.6	1.0	-0.6	1.9
Québec	-3.2	1.7	2.4	0.6	-1.0	2.3
Ontario	-3.3	2.1	2.1	0.3	-1.8	2.5
Manitoba	-3.0	3.2	3.3	2.0	-0.5	1.9
Sask.	-0.4	-0.4	2.8	3.4	0.6	1.1
Alberta	-1.3	6.6	3.3	0.6	-1.8	1.8
B.C.	-3.0	3.3	3.1	1.4	-1.0	3.6

E: Estimate. F: Forecast by TD Economics as at Dec. 2008
Source: Statistics Canada / Haver Analytics

NOMINAL GROSS DOMESTIC PRODUCT (GDP)
Annual average per cent change

	82/91	2006	2007	2008E	2009F	2010F
CANADA	3.1	5.7	5.9	4.3	-3.2	5.1
N. & L.	6.4	18.5	13.6	8.0	-2.1	5.2
P.E.I.	6.0	4.1	5.3	4.0	-2.2	3.5
N.S.	9.6	1.5	4.0	2.5	-0.8	3.7
N.B.	6.3	4.4	4.3	3.0	-2.1	3.6
Québec	3.5	3.9	5.4	2.5	-0.8	4.3
Ontario	3.0	4.3	4.5	2.0	-2.0	4.9
Manitoba	1.2	8.2	8.1	9.0	-2.5	4.5
Sask.	1.2	5.5	11.0	9.5	-5.0	4.8
Alberta	2.9	8.7	8.1	9.7	-9.8	5.8
B.C.	1.7	7.9	5.4	4.3	-2.0	6.5

E: Estimate. F: Forecast by TD Economics as at Dec. 2008
Source: Statistics Canada / Haver Analytics

EMPLOYMENT
Annual average per cent change

	82/91	2006	2007	2008E	2009F	2010F
CANADA	-2.4	1.9	2.3	1.6	-1.0	0.3
N. & L.	-1.9	0.7	0.7	1.8	0.3	0.5
P.E.I.	-2.0	0.5	1.2	1.5	-0.7	-0.2
N.S.	-1.7	-0.3	1.3	1.3	-0.4	0.0
N.B.	-2.6	1.4	2.1	0.9	-0.6	0.2
Québec	-3.6	1.3	2.3	0.8	-1.4	0.1
Ontario	-2.8	1.5	1.5	1.5	-1.7	0.5
Manitoba	-1.6	1.2	1.6	1.6	0.3	0.0
Sask.	-0.2	1.7	2.1	1.8	0.4	-0.2
Alberta	-0.5	4.8	4.7	2.7	-0.4	0.3
B.C.	-1.9	3.0	3.2	2.3	0.1	0.8

E: Estimate. F: Forecast by TD Economics as at Dec. 2008
Source: Statistics Canada / Haver Analytics

UNEMPLOYMENT RATE
Annual average, per cent

	82/91	2006	2007	2008E	2009F	2010F
CANADA	10.7	6.3	6.0	6.1	7.7	8.2
N. & L.	17.1	14.8	13.6	13.1	13.5	14.1
P.E.I.	14.6	11.1	10.3	10.6	11.6	12.4
N.S.	12.5	7.9	8.1	7.7	8.4	8.9
N.B.	13.4	8.7	7.6	8.6	9.4	10.1
Québec	13.1	8.0	7.2	7.3	8.8	9.2
Ontario	9.7	6.3	6.4	6.4	8.8	9.1
Manitoba	8.6	4.3	4.4	4.2	4.6	5.4
Sask.	6.8	4.6	4.2	4.2	4.8	6.1
Alberta	8.0	3.4	3.5	3.6	5.0	6.0
B.C.	11.1	4.8	4.2	4.5	5.3	6.0

E: Estimate. F: Forecast by TD Economics as at Dec. 2008
Source: Statistics Canada / Haver Analytics

TOTAL CONSUMER PRICE INDEX (CPI)
Annual average per cent change

	98-07	2006	2007	2008E	2009F	2010F
CANADA	2.1	2.0	2.1	2.5	0.5	1.6
N. & L.	1.9	1.8	1.4	3.0	1.1	2.0
P.E.I.	2.3	2.2	1.8	3.7	0.8	1.9
N.S.	2.3	2.1	1.9	3.4	0.8	1.5
N.B.	2.1	1.7	1.9	2.0	0.2	2.1
Québec	2.0	1.7	1.6	2.3	0.5	1.2
Ontario	2.1	1.8	1.8	2.3	0.5	1.4
Manitoba	2.0	1.9	2.1	2.2	0.7	1.7
Sask.	2.3	2.0	2.9	3.3	1.4	1.8
Alberta	3.0	3.9	4.9	3.4	0.2	1.9
B.C.	1.7	1.7	1.7	2.2	0.4	2.8

E: Estimate. F: Forecast by TD Economics as at Dec. 2008.
Source: Statistics Canada / Haver Analytics

RETAIL TRADE
Annual average per cent change

	1992	2006	2007	2008E	2009F	2010F
CANADA	2.5	6.4	5.8	4.3	2.5	3.5
N. & L.	-0.9	3.4	9.0	8.3	2.2	5.1
P.E.I.	6.2	6.2	7.7	5.3	1.8	3.1
N.S.	5.4	6.0	4.2	5.3	3.1	3.7
N.B.	4.0	5.9	5.7	5.4	3.0	3.9
Quebec	0.3	5.1	4.6	5.3	3.0	3.6
Ontario	2.7	4.1	3.9	4.6	2.7	3.6
Manitoba	2.0	3.9	8.8	8.1	3.8	3.0
Sask.	1.2	6.5	13.0	12.3	5.9	4.8
Alberta	3.1	15.4	9.3	1.0	1.5	2.5
B.C.	4.7	7.2	6.7	1.5	0.5	4.0

E: Estimate. F: Forecast by TD Economics as at Dec. 2008
Source: Statistics Canada / Haver Analytics

Main economic indicators

PROVINCES

REAL GDP

% growth	2005	2006	2007	**2008f**	**2009f**
Newfoundland & Labrador	3.0	3.0	9.1	**0.6**	**-1.3**
Prince Edward Island	2.4	2.4	2.4	**0.5**	**0.4**
Nova Scotia	0.9	0.9	1.7	**1.5**	**0.4**
New Brunswick	2.4	2.4	1.7	**1.0**	**0.2**
Quebec	1.7	1.7	2.6	**0.7**	**0.2**
Ontario	2.6	2.6	2.3	**0.1**	**-0.8**
Manitoba	4.0	4.0	3.3	**2.5**	**1.4**
Saskatchewan	-0.3	-0.3	2.5	**4.4**	**2.6**
Alberta	6.1	6.1	3.1	**1.0**	**0.9**
British Columbia	4.4	4.4	3.0	**1.0**	**0.9**

EMPLOYMENT

% growth	2005	2006	2007	**2008f**	**2009f**
Newfoundland & Labrador	-0.1	0.7	0.7	**1.3**	**0.5**
Prince Edward Island	2.0	0.5	1.2	**1.3**	**-0.3**
Nova Scotia	0.2	-0.3	1.3	**1.2**	**-0.2**
New Brunswick	0.1	1.4	2.1	**0.9**	**-0.3**
Quebec	1.0	1.3	2.3	**0.8**	**0.1**
Ontario	1.3	1.5	1.5	**1.5**	**-0.5**
Manitoba	0.6	1.2	1.6	**1.7**	**0.5**
Saskatchewan	0.8	1.7	2.1	**2.0**	**1.8**
Alberta	1.5	4.8	4.7	**2.8**	**0.9**
British Columbia	3.3	3.0	3.2	**2.2**	**0.4**

HOUSING STARTS

Thousands	2005	2006	2007	**2008f**	**2009f**
Newfoundland & Labrador	2.5	2.2	2.6	**3.0**	**2.7**
Prince Edward Island	0.9	0.7	0.7	**0.7**	**0.6**
Nova Scotia	4.8	4.9	4.8	**4.5**	**3.5**
New Brunswick	4.0	4.1	4.2	**4.4**	**3.3**
Quebec	50.9	47.9	48.6	**48.0**	**40.0**
Ontario	78.8	73.4	68.1	**75.0**	**60.0**
Manitoba	4.7	5.0	5.7	**5.7**	**5.0**
Saskatchewan	3.4	3.7	6.0	**7.0**	**4.6**
Alberta	40.8	49.0	48.3	**29.9**	**24.0**
British Columbia	34.7	36.4	39.2	**35.0**	**29.0**

f: forecast NBFG Economic Research

Schedule 34-1

2009														
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	**2009 FY**	
Residential	214,939	215,524	216,109	216,694	217,279	217,865	218,450	219,035	219,620	220,205	220,791	221,376	**218,157**	
GS<50	23,402	23,456	23,511	23,565	23,619	23,673	23,727	23,781	23,836	23,890	23,944	23,998	**23,700**	
GS>50	3,843	3,854	3,864	3,875	3,887	3,898	3,908	3,918	3,929	3,939	3,950	3,960	**3,902**	
Time of use	2	2	2	2	-	-	-	-	-	-	-	-	**1**	
Large Use	1	1	1	1	1	1	1	1	1	1	1	1	**1**	
USL	2,093	2,098	2,103	2,108	2,113	2,118	2,123	2,128	2,133	2,138	2,143	2,148	**2,121**	
Sentinel Lighting	142	142	142	142	142	142	142	142	142	142	142	142	**142**	
Street Lighting	62,598	62,817	63,037	63,256	63,476	63,695	63,914	64,134	64,353	64,573	64,792	65,012	**63,805**	
Total	307,020	307,894	308,768	309,643	310,517	311,391	312,265	313,140	314,014	314,888	315,762	316,637	**311,828**	As pe Schedule 4, page 7

Less Street light connections	65,012
Add SL customers	13
as per Schedule 3, page 4	251,638

2008														
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	**2008**	
Residential	208,516	208,843	208,974	209,572	210,169	210,767	211,365	211,963	212,560	213,158	213,756	214,353	**211,166**	
GS<50	22,748	22,781	22,868	22,921	22,975	23,028	23,081	23,135	23,188	23,241	23,295	23,348	**23,051**	
GS>50	3,725	3,777	3,735	3,746	3,757	3,768	3,779	3,789	3,800	3,811	3,822	3,833	**3,779**	
Time of use	2	2	2	2	2	2	2	2	2	2	2	2	**2**	
Large Use	1	1	1	1	1	1	1	1	1	1	1	1	**1**	
USL	2,028	2,051	2,070	2,072	2,074	2,076	2,078	2,080	2,082	2,084	2,086	2,088	**2,072**	
Sentinel Lighting	142	142	142	142	142	142	142	142	142	142	142	142	**142**	
Street Lighting	59,925	60,006	60,293	60,525	60,756	60,988	61,220	61,452	61,683	61,915	62,147	62,378	**61,107**	
Total	297,087	297,603	298,085	298,981	299,876	300,772	301,668	302,563	303,459	304,355	305,250	306,146	**301,320**	As pe Schedule 4, page 7

Less Street light connections	62,378
Add SL customers	13
as per Schedule 3, page 4	243,780

Schedule 34-1

2007														
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	**2007**	
Residential	201,381	201,749	202,030	202,608	203,284	203,909	204,624	205,323	205,670	206,402	207,192	207,783	**204,330**	
GS<50	22,138	22,169	22,345	22,382	22,454	22,496	22,560	22,577	22,568	22,620	22,658	22,698	**22,472**	
GS>50	3,688	3,707	3,560	3,575	3,594	3,613	3,636	3,665	3,681	3,652	3,686	3,708	**3,647**	
Time of use	2	2	2	2	2	2	2	2	2	2	2	2	**2**	
Large Use	1	1	1	1	1	1	1	1	1	1	1	1	**1**	
USL	2,103	2,056	2,021	2,023	2,011	2,015	2,015	2,017	2,022	2,024	2,030	2,028	**2,030**	
Sentinel Lighting	147	147	146	146	145	145	145	145	145	144	144	144	**145**	
Street Lighting	57,075	57,277	57,551	57,838	58,357	58,650	58,679	58,762	58,888	59,181	59,359	59,745	**58,447**	
Total	286,535	287,108	287,656	288,575	289,848	290,831	291,662	292,492	292,977	294,026	295,072	296,109	**291,074**	As pe Schedule 4, page 7

Less Street light connections	59,745
Add SL customers	13
as per Schedule 3, page 4	236,377

2006														
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	**2006**	
Residential	193,590	194,084	195,045	195,670	196,085	196,863	197,374	197,808	198,168	199,367	200,240	200,794	**197,091**	
GS<50	20,781	21,430	21,668	21,669	21,582	21,468	21,437	21,532	21,584	21,598	21,917	22,021	**21,557**	
GS>50	4,367	3,520	3,497	3,511	3,528	3,542	3,555	3,573	3,585	3,596	3,617	3,644	**3,628**	
Time of use	2	2	2	2	2	2	2	2	2	2	2	2	**2**	
Large Use	5	5	4	3	4	4	4	4	4	4	4	4	**4**	
USL	2,167	2,167	2,167	2,167	2,167	2,167	2,167	2,167	2,167	2,167	2,167	2,006	**2,154**	
Sentinel Lighting	154	154	175	155	151	151	151	151	151	151	149	148	**153**	
Street Lighting	54,266	55,128	55,364	55,565	55,823	55,878	55,543	55,496	55,377	55,858	55,945	56,810	**55,588**	
Total	275,332	276,490	277,922	278,742	279,342	280,075	280,233	280,733	281,038	282,743	284,041	285,429	**280,177**	As pe Schedule 4, page 7

Less Street light connections	56,810
Add SL customers	47
as per Schedule 3, page 4	228,666

POWERSTREAM - 2009 EDR EB-2008-0244

Revenue to Cost Ratios by Customer Class

	As per Information filing PowerStream RUN 2	Test Year at calculated rates	OEB PROPOSED RANGE		Proposed per Application
	2006	2009	Low	High	2009
Revenue /Expenses Ratio					
Residential	93.4%	93.3%	85.0%	115.0%	93.3%
GS Less Than 50 kW	113.5%	113.5%	80.0%	120.0%	113.5%
GS 50 to 4,999 kW	108.1%	107.2%	80.0%	180.0%	107.2%
GS 50 to 4,999 kW Legacy					
Large Use	75.9%	413.1%	85.0%	115.0%	115.0%
Unmetered Scattered Load	169.6%	119.5%	80.0%	120.0%	119.5%
Sentinel Lighting	16.4%	46.0%	70.0%	120.0%	70.0%
Street Lighting	54.4%	64.7%	70.0%	120.0%	70.0%

	As per Information filing PowerStream RUN 2	Test Year at calculated rates	Proposed per Application
Total Revenue (Costs Allocated)	2006	2009	2009
(line 35, CA model)			
Residential	58,397,913	69,397,488	69,397,488
GS Less Than 50 kW	16,255,808	17,389,590	17,389,590
GS 50 to 4,999 kW	30,817,558	37,753,577	37,753,577
GS 50 to 4,999 kW Legacy			-
Large Use	1,729,521	52,480	52,480
Unmetered Scattered Load	335,613	475,287	475,287
Sentinel Lighting	46,200	27,548	27,548
Street Lighting	1,351,605	1,776,238	1,776,238
Total	108,934,219	126,872,208	126,872,208

	As per Information filing	Test Year at calculated rates	Proposed per Application
Total Revenue requirement	2006	2009	2009
tab O1, line 20			
Residential	54,545,141	64,718,044	64,774,516
GS Less Than 50 kW	18,449,078	19,740,298	19,740,298
GS 50 to 4,999 kW	33,316,307	40,466,407	40,466,407
GS 50 to 4,999 kW Legacy	-	-	-
Large Use	1,312,156	216,805	60,352
Unmetered Scattered Load	569,255	567,985	567,985
Sentinel Lighting	7,581	12,683	19,284
Street Lighting	734,701	1,149,987	1,243,367
Total	108,934,219	126,872,208	126,872,208

Miscellanious revenue			
tab O1, line 19			
Residential	3,394,822	3,593,024	3,593,024
GS Less Than 50 kW	1,383,906	1,596,411	1,596,411
GS 50 to 4,999 kW	1,238,742	1,273,225	1,273,225
GS 50 to 4,999 kW Legacy			-
Large Use	37,458	884	884
Unmetered Scattered Load	15,334	86,843	86,843
Sentinel Lighting	1,369	521	521
Street Lighting	24,717	17,138	17,138
Total	6,096,348	6,568,046	6,568,046

	As per Information filing	Test Year at calculated rates	Distribution revenue re-allocation	Proposed per Application
Distribution Revenue Requirement	2006	2009	2009	2009
	tab O1, line 18			
Residential	51,150,319	61,125,021	56,472	61,181,493
GS Less Than 50 kW	17,065,172	18,143,886		18,143,886
GS 50 to 4,999 kW	32,077,565	39,193,181		39,193,181
GS 50 to 4,999 kW Legacy		-		-
Large Use	1,274,698	215,920	(156,452)	59,468
Unmetered Scattered Load	553,921	481,142		481,142
Sentinel Lighting	6,212	12,162	6,601	18,763
Street Lighting	709,984	1,132,849	93,379	1,226,229
Total	102,837,871	120,304,162	0	120,304,162

Schedule VECC 52-1

TOTAL RESOURCE COST TEST CALCULATOR
2006 Summer Every KiloWatt Counts Campaign

LDC Information	
Discount Rate	7.30%
Local Water Rate (per 000's litres)	**$0.876**

Products Sold	
CFLs	45,877
Ceiling Fans	821
Timers	2,149
Program Thermostats	696
Program Costs	$5,318,155

Part 2. Results by Technology

Total Resource Cost Test Results by Technology (2007 $'s)

Technology	TRC Benefits	TRC Costs	TRC Net Benefits	TRC Benefit Cost Ratio	Summer Peak kW Savings	Net Annual kWh Savings	Net Lifecycle kWh Savings	Free Ridership	Gross Annual kWh Savings	Gross Lifecycle kWh Savings		Lifespan
CFLs	$975,233	$92,900	$882,333	10.50	-	4,296,210	17,184,840	10%	4,773,567	19,094,266		4
Ceiling Fans	$99,413	$18,473	$80,941	5.38	10.54	103,889	2,077,787	10%	115,433	2,308,652		20
Timers	$324,772	$24,176	$300,596	13.43	-	352,973	7,059,465	10%	392,193	7,843,850		20
Programmable Thermostats	$136,726	$40,716	$96,010	3.36	31.32	136,559	2,458,067	10%	151,733	2,731,186		18
Admin			$0									
Totals	$1,536,144	$176,265	$1,359,879		41.86	4,889,632	28,780,159		5,432,924	31,977,954	Total	
					46.5131							

Part 3. Program Results

Schedule 52-2

Instructions for Calculating Total Resource Cost Test Results
2006 Fall Every KiloWatt Counts Campaign

Part 1
a. Enter Discount Rate (refer to page 5 of the Ontario Energy Board Total Resource Cost Test Guide, Revised October 2, 2006.)

Discount Rate **6.55%**

b. Enter number of coupons redeemed by technology.

Products	Number of Coupons
Baseboard Programmable Thermostats	**344**
Dimmers	**1398**
Energy Star CFL's	**16694**
Motion Sensor Light Switch	**604**
Programmable Thermostat	**2471**
Seasonal LED Lights	**12825**

c. Enter program dollars (refer to page 10 of the Ontario Energy Board Total Resource Cost Test Guide, Revised October 2, 2006.)

Program Costs: **$ 5,089,954**

Part 2
Program Total Resource Cost Test Results

Calculation of Program TRC Benefits
Sum of TRC Benefits for all technologies

Calculation of Program TRC Costs
Sum of TRC Costs for all technologies plus Program Costs

Calculation of Program TRC Net Benefits
= TRC Benefits - TRC Costs

Schedule 52-2

Fall EKC		
Technology	**Number of Participants**	**Free Ridership**
Compact Fluorescent Bulbs	47745	10.00%
LED Christmas Lights (indoor or outdoor) Replacing 5w Christmas Lights C-7 (25 Lights)	6413	5.00%
LED Christmas Lights (indoor or outdoor) Replacing Incandescent Mini Lights	6413	5.00%
Programmable Thermostat - Space Heating, Existing Single Family Detached	427	10.00%
Programmable Thermostat - Space Cooling, Existing Single Family Detached	1112	10.00%
pStat Baseboard	86	10.00%
Dimmer	1398	10.00%
Motion Sensor	604	10.00%

Schedule 52-2

Fall EKC					
Technology	**Summer Peak kW Savings**	**Winter Peak kW Savings**	**Annual kWh Savings in Year**	**Measure Life**	**Lifecycle kWh Savings**
Compact Fluorescent Bulbs	0	988.32	4,486,105	4	17,944,420.67
LED Christmas Lights (indoor or outdoor) Replacing 5w Christmas Lights C-7 (25 Lights)	0.00	115.75	256820.63	30	7,704,618.75
LED Christmas Lights (indoor or outdoor) Replacing Incandescent Mini Lights	0.00	42.64	98111.25	30	2,943,337.50
Programmable Thermostat - Space Heating, Existing Single Family Detached	0.00	66.56	564136.49	18	10,154,456.83
Programmable Thermostat - Space Cooling, Existing Single Family Detached	163.12	0.00	159220.12	18	2,865,962.17
pStat Baseboard	0.00	77.40	113491.62	18	2,042,849.16
Dimmer	0.00	113.24	174889.80	10	1,748,898.00
Motion Sensor		73.39	113612.40	20	2,272,248.00
Total	**163.12**	**1477.29**	**5,966,387**		**47,676,791**

Schedule 52-2

Fall EKC					
Technology	TRC Benefits	Incremental Equipment Costs	Program Costs	TRC Net Benefits	TRC B/C Ratio
Compact Fluorescent Bulbs	$1,028,994.34	$77,346.64		$951,648	13.30
LED Christmas Lights (indoor or outdoor) Replacing 5w Christmas Lights C-7 (25 Lights)	$346,172	$12,184		$333,988	28.41
LED Christmas Lights (indoor or outdoor) Replacing Incandescent Mini Lights	$131,924	$12,184		$119,741	10.83
Programmable Thermostat - Space Heating, Existing Single Family Detached	$485,511	$23,084		$462,427	21.03
Programmable Thermostat - Space Cooling, Existing Single Family Detached	$243,597	$60,045		$183,552	4.06
pStat Baseboard	$106,296	$4,644		$101,652	22.89
Dimmer	$97,634	$25,164		$72,470	3.88
Motion Sensor	$78,041	$3,805		$74,236	20.51
Utility Program Costs			$ 5,089,954.38		
Total	**$2,518,170**	**$218,457**	**$5,089,954**	**($2,790,241)**	**0.49**

Schedule VECC 52-2

Fall EKC							Gross	
Technology	Summer Peak kW Savings	Winter Peak kW Savings	Annual kWh Savings in Year	Measure Life	Lifecycle kWh Savings	**Free Ridership**	Annual kWh Savings in Year	Lifecycle kWh Savings
Compact Fluorescent Bulbs	-	988	4,486,105	4	17,944,421	10.00%	4,984,561	19,938,245
LED Christmas Lights (indoor or outdoor) Replacing 5w Christmas Lights C-7 (25 Lights)	-	116	256,821	30	7,704,619	5.00%	270,338	8,110,125
LED Christmas Lights (indoor or outdoor) Replacing Incandescent Mini Lights	-	43	98,111	30	2,943,338	5.00%	103,275	3,098,250
Programmable Thermostat - Space Heating, Existing Single Family Detached	-	67	564,136	18	10,154,457	10.00%	626,818	11,282,730
Programmable Thermostat - Space Cooling, Existing Single Family Detached	163	-	159,220	18	2,865,962	10.00%	176,911	3,184,402
pStat Baseboard	-	77	113,492	18	2,042,849	10.00%	126,102	2,269,832
Dimmer	-	113	174,890	10	1,748,898	10.00%	194,322	1,943,220
Motion Sensor		73	113,612	20	2,272,248	10.00%	126,236	2,524,720
Total	163	1,477	5,966,387		47,676,791		6,608,563	52,351,525
	181.24785	1,632.17						

SMART METER RATE CALCULATION MODEL

Sheet 1 Utility Information Sheet

Legend:	Input Cell	Pull-Down Menu Option	Output Cell
	From Another Sheet		To Another Sheet

Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.

Name of LDC: PowerStream Inc.

Licence Number: ED-2004-0420 **Smart Meter Grouping:** Listed

EDR 2009 EB Number: EB-2008-0244

Date of Submission: October 10, 2008 **Revision:**

Version:

Contact Information

Name: Tom Barrett

Title: Manager, Rates

Phone Number: 905.532.4640

E-Mail Address: tom.barrett.powerstream.ca

PowerStream Inc.
EB-2008-0244
Friday, October 10, 2008
Sheet 2. Smart Meter Capital Cost and Operational Expense Data

Smart Meter Unit Installation Plan:
assume calendar year installation

	2006	2007 Actual To April	2007 Actual	2008 Actual	2009	2010	Total
Planned number of Residential smart meters to be installed - includes new services	-	-	82,293	53,262	51,083	36,000	222,638
Planned number of General Service Less Than 50 kW smart meters - includes new services	-				13,807	10,841	
Planned number of General Service Greater Than 50 kW smart meters - includes new services	-				110	3,134	3,244
Planned Meter Installation	-	-	82,293	53,262	65,000	49,975	250,530
Accumulative Planned Meter Installations Completed before January 1, 2011		-	82,293	135,555	200,555	250,530	

Capital Costs

1.1 ADVANCED METERING COMMUNICATION DEVICE (AMCD)

	Asset Type	2006	2007	2007 Actual	2008 Actual	2009	2010	Total
1.1.1 Smart Meter *may include new meters and modules, etc.*	**Smart Meter**				$ 4,629,163	$ 10,190,514	$ 10,482,778	$ 25,302,455
1.1.2 Installation Cost *may include socket kits plus shipping, labour, benefits, vehicle, etc.*	**Smart Meter**				$ 678,701	$ 1,859,339	$ 1,640,233	$ 4,178,273
1.1.3a Workforce Automation Hardware *may include fieldworker handhelds, barcode hardware, etc.*	**Comp. Hard.**							$ -
1.1.3b Workforce Automation Software *may include fieldworker handhelds, barcode hardware, etc.*	**Comp. Soft.**							$ -
Total Advanced Metering Communication Device (AMCD)		**$ -**	**$ -**	**$ -**	**$ 5,307,864**	**$ 12,049,853**	**$ 12,123,011**	**$ 29,480,728**

1.2 ADVANCED METERING REGIONAL COLLECTOR (AMRC) (includes LAN)

	Asset Type	2006	2007	2007 Actual	2008 Actual	2009	2010	Total
1.2.1 Collectors	**Smart Meter**				$ 395,634	$ 268,400	$ 144,200	$ 808,234
1.2.2 Repeaters *may include radio licence, etc.*	**Smart Meter**							$ -
1.2.3 Installation *may include meter seals and rings, collector computer hardware, etc.*	**Smart Meter**							$ -
Total Advanced Metering Regional Collector (AMRC) (includes LAN)		**$ -**	**$ -**	**$ -**	**$ 395,634**	**$ 268,400**	**$ 144,200**	**$ 808,234**

1.3 ADVANCED METERING CONTROL COMPUTER (AMCC)

	Asset Type	2006	2007	2007 Actual	2008 Actual	2009	2010	Total
1.3.1 Computer Hardware	**Comp. Hard.**				$ 18,623			$ 18,623
1.3.2 Computer Software	**Comp. Soft.**							$ -
1.3.3 Computer Software Licence & Installation (includes hardware & software) *may include AS/400 disc space, backup & recovery computer, UPS, etc*	**Comp. Soft.**							$ -
Total Advanced Metering Control Computer (AMCC)		**$ -**	**$ -**	**$ -**	**$ 18,623**	**$ -**	**$ -**	**$ 18,623**

Schedule VECC 55-1

PowerStream Inc.
EB-2008-0244
Friday, October 10, 2008
Sheet 2. Smart Meter Capital Cost and Operational Expense Data

1.4 WIDE AREA NETWORK (WAN)

		2006	2007	2007 Actual	2008 Actual	2009	2010	Total
1.4.1 Activation Fees	**Comp. Soft.**							$ -
Total Wide Area Network (WAN)		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

1.5 OTHER AMI CAPITAL COSTS RELATED TO MINIMUM FUNCTIONALITY

		2006	2007	2007 Actual	2008 Actual	2009	2010	Total
1.5.1 Customer equipment (including repair of damaged equipment)	**Comp. Hard.**							$ -
1.5.2 AMI Interface to CIS	**Comp. Soft.**				$ 504,639	$ 300,000	$ 100,000	$ 904,639
1.5.3 Professional Fees	**Comp. Hard.**				$ 152,152	$ 50,000	$ 50,000	$ 252,152
1.5.4 Integration	**Comp. Hard.**					$ 48,600	$ 48,600	$ 97,200
1.5.5 Program Management	**Comp. Hard.**				$ 137,853	$ 150,000	$ 150,000	$ 437,853
1.5.6 Other AMI Capital	**Comp. Hard.**					$ 108,000		$ 108,000
Total Other AMI Capital Costs Related To Minimum Functionality		**$ -**	**$ -**	**$ -**	**$ 794,644**	**$ 656,600**	**$ 348,600**	**$ 1,799,844**

3. LDC Assumptions and Data

	2006	2007	2007 Actual	2008 Actual	2009	2010	Total
Total Capital Costs	**$ -**	**$ -**	**$ -**	**$ 6,516,765**	**$ 12,974,853**	**$ 12,615,811**	**$ 32,107,429**

O M & A

2.1 ADVANCED METERING COMMUNICATION DEVICE (AMCD)

	2006	2007	2007 Actual	2008 Actual	2009	2010	Total
2.1.1 Maintenance *may include meter reverification costs, etc.*		$ -			$ 250,000	$ 250,000	$ 500,000
Total Incremental AMI Operation Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ 250,000**	**$ 250,000**	**$ 500,000**

2.2 ADVANCED METERING REGIONAL COLLECTOR (AMRC) (includes LAN)

	2006	2007	2007 Actual	2008 Actual	2009	2010	Total
2.2.1 Maintenance				$ 29,657	$ 35,000	$ 35,000	$ 99,657
Total Advanced Metering Regional Collector (AMRC) (includes LAN)	**$ -**	**$ -**	**$ -**	**$ 29,657**	**$ 35,000**	**$ 35,000**	**$ 99,657**

2.3 ADVANCED METERING CONTROL COMPUTER (AMCC)

	2006	2007	2007 Actual	2008 Actual	2009	2010	Total
2.3.1 Hardware Maintenance *may include server support, etc*							$ -
2.3.2 Software Maintenance *may include maintenance support, etc.*							$ -
Total Advanced Metering Control Computer (AMCC)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

2.4 WIDE AREA NETWORK (WAN)

	2006	2007	2007 Actual	2008 Actual	2009	2010	Total
2.4.1 WIDE AREA NETWORK (WAN) *may include serial to Ethernet hardware, etc.*		$ -		$ 266,148	-$ 177,800	-$ 197,000	-$ 108,652
Total Incremental Other Operation Expenses	**$ -**	**$ -**	**$ -**	**$ 266,148**	**-$ 177,800**	**-$ 197,000**	**-$ 108,652**

PowerStream Inc.
EB-2008-0244
Friday, October 10, 2008

Sheet 2. Smart Meter Capital Cost and Operational Expense Data

2.5 OTHER AMI OM&A COSTS RELATED TO MINIMUM FUNCTIONALITY

	2006	2007	2007 Actual	2008 Actual	2009	2010	Total
2.5.1 Business Process Redesign							$ -
2.5.2 Customer Communication *may include project communication. etc.*		$ -		$ 106,926	$ 100,000	$ 100,000	$ 306,926
2.5.3 Program Management							$ -
2.5.4 Change Management *may include training, etc.*		$ -		$ 101,875	$ 75,000	$ 75,000	$ 251,875
2.5.5 Administration Cost					$ 13,500	$ 13,500	$ 27,000
2.5.6 Other AMI Expenses		$ -		$ 676,352	$ 645,750	$ 1,295,700	$ 2,617,802
Total 2.5 Other AMI OM&A Costs Related To Minimum Functionality	**$ -**	**$ -**	**$ -**	**$ 885,153**	**$ 834,250**	**$ 1,484,200**	**$ 3,203,603**
Total O M & A Costs	**$ -**	**$ -**	**$ -**	**$ 1,180,958**	**$ 941,450**	**$ 1,572,200**	**$ 3,694,608**

Schedule VECC 55-1

PowerStream Inc.
EB-2008-0244
Friday, October 10, 2008
Sheet 3. LDC Assumptions and Data

Assumptions:
1. Planned meter installations occur evenly through the year.
2. Year assumed January to December
3. Amortization is straight line and has half year rule applied in first year

2009 EDR Data Information

Deemed Debt (from 2009 PS future test Year Application)	60%
Deemed Equity (from 2009 PS future test Year Rate Application)	40%
Weighted Debt Rate (from 2009 PS future test year rate application)	5.75%
Proposed ROE (from 2009 PS future test year Rate application)	8.40%
Weighted Average Cost of Capital	6.81%

Working Capital Allowance % — 15.00%

2009 EDR Total Metered Customers

Residential	218,157
General Service Less Than 50 kW	23,700
Other Metered Customers	3,903
Sum of Residential, General Service, and Large User	245,760
	-

Smart Meter Rate Adders

	Residential	GS and LU
2006 EDR Smart Meter Rate Adder	$ 0.27	$ 0.27
2007 EDR Smart Meter Rate Adder	$ 0.73	$ 0.73
2008 EDR Smart Meter Rate Adder	$ 1.21	$ 1.21
2009 EDR Smart Meter Rate Adder	$ -	$ -
2010 EDR Smart Meter Rate Adder	$ -	$ -

2009 EDR Tax Rate

Corporate Income Tax Rate *(from 2009 PS future test year rate application)*	33.00%

Capital Data:

	2006 Actual	2007 Actual	2007 Estimate	2008 Forecast	2009	2010	Total
Smart Meter	$ -	$ -	$ -	$ 5,703,498	$ 12,318,253	$ 12,267,211	$ 30,288,962
Computer Hardware	$ -	$ -	$ -	$ 308,628	$ 356,600	$ 248,600	$ 913,828
Computer Software	$ -	$ -	$ -	$ 504,639	$ 300,000	$ 100,000	$ 904,639
Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Capital Costs	$ -	$ -	$ -	$ 6,516,765	$ 12,974,853	$ 12,615,811	$ 32,107,429

LDC Amortization Policy:

	Amortization		CCA Class	CCA Rate	
Smart Meter Amortization Rate *Enter Amortization Policy*	15	Years	47	8	%
Computer Hardware Amortization Rate *Enter Amortization Policy*	5	Years	45	45	%
Computer Software Amortization Rate *Enter Amortization Policy*	3	Years	45	45	%
Tools & Equipment Amortization Rate *Enter Amortization Policy*	10	Years	8	20	%
Other Equipment Amortization Rate *Enter Amortization Policy*	10	Years	8	20	%

Operating Expense Data:

	2006 Actual	2007 Actual	2007 Estimate	2008 Forecast	2009	2010	Total
2.1 Advanced Metering Communication Device (AMCD)	$ -	$ -	$ -	$ -	$ 250,000	$ 250,000	$ 500,000
2.2 Advanced Metering Regional Collector (AMRC) (includes LAN)	$ -	$ -	$ -	$ 29,657	$ 35,000	$ 35,000	$ 99,657
2.3 Advanced Metering Control Computer (AMCC)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2.4 Wide Area Network (WAN)	$ -	$ -	$ -	$ 266,148	-$ 177,800	-$ 197,000	-$ 108,652
2.5 Other AMI OM&A Costs Related To Minimum Functionality	$ -	$ -	$ -	$ 885,153	$ 834,250	$ 1,484,200	$ 3,203,603
Total O M & A Costs	$ -	$ -	$ -	$ 1,180,958	$ 941,450	$ 1,572,200	$ 3,694,608

Per Meter Cost Split:

	Per Meter	Installed	Investment	% of Invest
Smart meter including installation	$ 120.90	250,530	$ 30,288,962	85%
Computer Hardware Costs	$ 3.65	250,530	$ 913,828	3%
Computer Software Costs	$ 3.61	250,530	$ 904,639	3%
Tools & Equipment	$ -	250,530	$ -	0%
Other Equipment	$ -	250,530	$ -	0%
Smart meter incremental operating expenses	$ 14.75	250,530	$ 3,694,608	10%
Total Smart Meter Capital Costs per meter	$ 142.91		$ 35,802,037	100%

PowerStream Inc.
EB-2008-0244
Friday, October 10, 2008
Sheet 4. Smart Meter Rate Calc

Smart Meter Rate Calculation

	2007 Estimate			2008 Actuals			2009 Forecast			2010		
Average Asset Values												
Net Fixed Assets Smart Meters	$ -			$ 2,756,691			$ 11,277,087			$ 22,369,220		
Net Fixed Assets Computer Hardware	$ -			$ 138,883			$ 407,372			$ 582,327		
Net Fixed Assets Computer Software	$ -			$ 210,266			$ 461,426			$ 409,880		
Net Fixed Assets Tools & Equipment	$ -			$ -			$ -			$ -		
Net Fixed Assets Other Equipment	$ -			$ -			$ -			$ -		
Total Net Fixed Assets	$ -	$ -		$ 3,105,840	$ 3,105,840		$ 12,145,885	$ 12,145,885		$ 23,361,426	$ 23,361,426	
Working Capital												
Operation Expense	$ -			$ 1,180,958			$ 941,450			$ 1,572,200		
Working Capital 15 %	$ -	$ -		$ 177,144	$ 177,144		$ 141,218	$ 141,218		$ 235,830	$ 235,830	
Smart Meters included in Rate Base		$ -			$ 3,282,983			$ 12,287,103			$ 23,597,256	
Return on Rate Base												
Deemed Debt *(3. LDC Assumptions and Data)*	60%	$ -		60%	$ 1,969,790		60%	$ 7,372,262		60%	$ 14,158,354	
Deemed Equity *(3. LDC Assumptions and Data)*	40%	$ -		40%	$ 1,313,193		40%	$ 4,914,841		40%	$ 9,438,902	
		$ -			$ 3,282,983			$ 12,287,103			$ 23,597,256	
Weighted Debt Rate *(3. LDC Assumptions and Data)*	5.75%	$ -		5.75%	$ 113,263		5.75%	$ 423,905		5.75%	$ 814,105	
Proposed ROE *(3. LDC Assumptions and Data)*	8.40%	$ -		8.40%	$ 110,308		8.40%	$ 412,847		8.40%	$ 792,868	
Return on Rate Base		$ -	$ -		$ 223,571	$ 223,571		$ 836,752	$ 836,752		$ 1,606,973	$ 1,606,973
Operating Expenses												
Incremental Operating Expenses *(3. LDC Assumptions and Data)*			$ -			$ 1,180,958			$ 941,450			$ 1,572,200
Amortization Expenses												
Amortization Expenses - Smart Meters		$ -			$ 190,117			$ 790,842			$ 1,610,357	
Amortization Expenses - Computer Hardware		$ -			$ 30,863			$ 97,386			$ 157,906	
Amortization Expenses - Computer Software		$ -			$ 84,107			$ 218,213			$ 284,880	
Amortization Expenses - Tools & Equipment		$ -			$ -			$ -			$ -	
Amortization Expenses - Other Equipment		$ -			$ -			$ -			$ -	
Total Amortization Expenses			$ -			$ 305,086			$ 1,106,440			$ 2,053,142
Revenue Requirement Before PILs			$ -			$ 1,709,615			$ 2,884,642			$ 5,232,316
Calculation of Taxable Income												
Incremental Operating Expenses			$ -			-$ 1,180,958			-$ 941,450			-$ 1,572,200
Depreciation Expenses			$ -			-$ 305,086			-$ 1,106,440			-$ 2,053,142
Interest Expense			$ -			-$ 113,263			-$ 423,905			-$ 814,105
Taxable Income For PILs			$ -			$ 110,308			$ 412,847			$ 792,868
Grossed up PILs *(5. PILs)*			$ -			$ 19,854			$ 129,521			$ 351,028
Revenue Requirement Before PILs			$ -			$ 1,709,615			$ 2,884,642			$ 5,232,316
Grossed up PILs *(5. PILs)*			$ -			$ 19,854			$ 129,521			$ 351,028
Revenue Requirement for Smart Meters			**$ -**			**$ 1,729,469**			**$ 3,014,162**			**$ 5,583,344**
2009 Smart Meter Rate Adder												
Revenue Requirement for Smart Meters			$ -			$ 1,729,469			$ 3,014,162			$ 5,583,344
2009 EDR Total Metered Customers *(3. LDC Assumptions and Data)*			$ 245,760			$ 245,760			$ 245,760			$ 245,760
Annualized amount required per metered customer			$ -			$ 7.04			$ 12.26			$ 22.72
Number of months in year			12			12			12			12
2009 Smart Meter Rate Adder			**$ -**			**$ 0.59**			**$ 1.02**			**$ 1.89**

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Sheet 5. PILs

PILs Calculation

	2007 Estimate	2008	2009	2010
INCOME TAX				
Net Income	$ -	$ 110,308	$ 412,847	$ 792,868
Amortization	$ -	$ 305,086	$ 1,106,440	$ 2,053,142
CCA - Class 47 (8%) Smart Meters	$ -	-$ 228,140	-$ 930,759	-$ 1,839,717
CCA - Class 45 (45%) Computers	$ -	-$ 182,985	-$ 431,362	-$ 463,419
CCA - Class 8 (20%) Other Equipment	$ -	$ -	$ -	$ -
Change in taxable income	$ -	$ 4,269	$ 157,166	$ 542,875
Tax Rate *(3. LDC Assumptions and Data)*	33.50%	33.50%	33.00%	33.00%
Income Taxes Payable	$ -	$ 1,430	$ 51,865	$ 179,149
ONTARIO CAPITAL TAX				
Smart Meters	$ -	$ 5,513,381	$ 17,040,793	$ 27,697,647
Computer Hardware	$ -	$ 277,765	$ 536,980	$ 627,674
Computer Software	$ -	$ 420,533	$ 502,320	$ 317,440
Tools & Equipment	$ -	$ -	$ -	$ -
Other Equipment	$ -	$ -	$ -	$ -
Rate Base	$ -	$ 6,211,679	$ 18,080,092	$ 28,642,761
Less: Exemption	$ -	$ -	$ -	$ -
Deemed Taxable Capital	$ -	$ 6,211,679	$ 18,080,092	$ 28,642,761
Ontario Capital Tax Rate	0.285%	0.285%	0.285%	0.285%
Net Amount (Taxable Capital x Rate)	$ -	$ 17,703	$ 51,528	$ 81,632

Gross Up

	PILs Payable	PILs Payable	PILs Payable	PILs Payable
Change in Income Taxes Payable	$ -	$ 1,430	$ 51,865	$ 179,149
Change in OCT	$ -	$ 17,703	$ 51,528	$ 81,632
PIL's	$ -	$ 19,133	$ 103,393	$ 260,780
	Gross Up	Gross Up	Gross Up	Gross Up
	33.50%	33.50%	33.50%	33.50%
	Grossed Up PILs	Grossed Up PILs	Grossed Up PILs	Grossed Up PILs
Change in Income Taxes Payable	$ -	$ 2,151	$ 77,992	$ 269,396
Change in OCT	$ -	$ 17,703	$ 51,528	$ 81,632
PIL's	**$ -**	**$ 19,854**	**$ 129,521**	**$ 351,028**

Schedule VECC 55-1

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Sheet 6. SM Avg Net Fixed Assets &UCC

Smart Meter Average Net Fixed Assets

Net Fixed Assets - Smart Meters

	2007 Estimate	2008	2009	2010
Opening Capital Investment	$ -	$ -	$ 5,703,498.00	$ 18,021,751.00
Capital Investment *(3. LDC Assumptions and Data)*	$ -	$ 5,703,498.00	$ 12,318,253.00	$ 12,267,211.00
Closing Capital Investment	$ -	$ 5,703,498.00	$ 18,021,751.00	$ 30,288,962.00
Opening Accumulated Amortization	$ -	$ -	$ 190,116.60	$ 980,958.23
Amortization Year 1 (15 Years Straight Line)	$ -	$ 190,116.60	$ 790,841.63	$ 1,610,357.10
Closing Accumulated Amortization	$ -	$ 190,116.60	$ 980,958.23	$ 2,591,315.33
Opening Net Fixed Assets	$ -	$ -	$ 5,513,381.40	$ 17,040,792.77
Closing Net Fixed Assets	$ -	$ 5,513,381.40	$ 17,040,792.77	$ 27,697,646.67
Average Net Fixed Assets	$ -	$ 2,756,690.70	$ 11,277,087.08	$ 22,369,219.72

Net Fixed Assets - Computer Hardware

	2007 Estimate	2008	2009	2010
Opening Capital Investment	$ -	$ -	$ 308,628.00	$ 665,228.00
Capital Investment *(3. LDC Assumptions and Data)*	$ -	$ 308,628.00	$ 356,600.00	$ 248,600.00
Closing Capital Investment	$ -	$ 308,628.00	$ 665,228.00	$ 913,828.00
Opening Accumulated Amortization	$ -	$ -	$ 30,862.80	$ 128,248.40
Amortization Year 1 (5 Years Straight Line)	$ -	$ 30,862.80	$ 97,385.60	$ 157,905.60
Closing Accumulated Amortization	$ -	$ 30,862.80	$ 128,248.40	$ 286,154.00
Opening Net Fixed Assets	$ -	$ -	$ 277,765.20	$ 536,979.60
Closing Net Fixed Assets	$ -	$ 277,765.20	$ 536,979.60	$ 627,674.00
Average Net Fixed Assets	$ -	$ 138,882.60	$ 407,372.40	$ 582,326.80

Net Fixed Assets - Computer Software

	2007 Estimate	2008	2009	2010
Opening Capital Investment	$ -	$ -	$ 504,639.00	$ 804,639.00
Capital Investment *(3. LDC Assumptions and Data)*	$ -	$ 504,639.00	$ 300,000.00	$ 100,000.00
Closing Capital Investment	$ -	$ 504,639.00	$ 804,639.00	$ 904,639.00
Opening Accumulated Amortization	$ -	$ -	$ 84,106.50	$ 302,319.50
Amortization Year 1 (3 Years Straight Line)	$ -	$ 84,106.50	$ 218,213.00	$ 284,879.67
Closing Accumulated Amortization	$ -	$ 84,106.50	$ 302,319.50	$ 587,199.17
Opening Net Fixed Assets	$ -	$ -	$ 420,532.50	$ 502,319.50
Closing Net Fixed Assets	$ -	$ 420,532.50	$ 502,319.50	$ 317,439.83
Average Net Fixed Assets	$ -	$ 210,266.25	$ 461,426.00	$ 409,879.67

Schedule VECC 55-1

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Sheet 6. SM Avg Net Fixed Assets &UCC

Net Fixed Assets - Tools & Equipment

	2007 Estimate	2008	2009	2010
Opening Capital Investment	$ -	$ -	$ -	$ -
Capital Investment *(3. LDC Assumptions and Data)*	$ -	$ -	$ -	$ -
Closing Capital Investment	$ -	$ -	$ -	$ -
Opening Accumulated Amortization	$ -	$ -	$ -	$ -
Amortization Year 1 (10 Years Straight Line)	$ -	$ -	$ -	$ -
Closing Accumulated Amortization	$ -	$ -	$ -	$ -
Opening Net Fixed Assets	$ -	$ -	$ -	$ -
Closing Net Fixed Assets	$ -	$ -	$ -	$ -
Average Net Fixed Assets	$ -	$ -	$ -	$ -

Net Fixed Assets - Other Equipment

	2007 Estimate	2008	2009	2010
Opening Capital Investment	$ -	$ -	$ -	$ -
Capital Investment *(3. LDC Assumptions and Data)*	$ -	$ -	$ -	$ -
Closing Capital Investment	$ -	$ -	$ -	$ -
Opening Accumulated Amortization	$ -	$ -	$ -	$ -
Amortization Year 1 (10 Years Straight Line)	$ -	$ -	$ -	$ -
Closing Accumulated Amortization	$ -	$ -	$ -	$ -
Opening Net Fixed Assets	$ -	$ -	$ -	$ -
Closing Net Fixed Assets	$ -	$ -	$ -	$ -
Average Net Fixed Assets	$ -	$ -	$ -	$ -

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Sheet 6. SM Avg Net Fixed Assets &UCC

For PILs Calculation

UCC - Smart Meters

CCA Class 47 (8%)	2007 Estimate	2008	2009	2010
Opening UCC	$ -	$ -	$ 5,475,358.08	$ 16,862,852.31
Capital Additions	$ -	$ 5,703,498.00	$ 12,318,253.00	$ 12,267,211.00
UCC Before Half Year Rule	$ -	$ 5,703,498.00	$ 17,793,611.08	$ 29,130,063.31
Half Year Rule (1/2 Additions - Disposals)	$ -	$ 2,851,749.00	$ 6,159,126.50	$ 6,133,605.50
Reduced UCC	$ -	$ 2,851,749.00	$ 11,634,484.58	$ 22,996,457.81
CCA Rate Class 47	8.0%	8.0%	8.0%	8.0%
CCA	$ -	$ 228,139.92	$ 930,758.77	$ 1,839,716.63
Closing UCC	$ -	$ 5,475,358.08	$ 16,862,852.31	$ 27,290,346.69

UCC - Computer Equipment

CCA Class 45 (45%)	2007 Estimate	2008	2009	2010
Opening UCC	$ -	$ -	$ 630,281.93	$ 855,520.06
Capital Additions Computer Hardware	$ -	$ 308,628.00	$ 356,600.00	$ 248,600.00
Capital Additions Computer Software	$ -	$ 504,639.00	$ 300,000.00	$ 100,000.00
UCC Before Half Year Rule	$ -	$ 813,267.00	$ 1,286,881.93	$ 1,204,120.06
Half Year Rule (1/2 Additions - Disposals)	$ -	$ 406,633.50	$ 328,300.00	$ 174,300.00
Reduced UCC	$ -	$ 406,633.50	$ 958,581.93	$ 1,029,820.06
CCA Rate Class 45	45%	45%	45%	45%
CCA	$ -	$ 182,985.08	$ 431,361.87	$ 463,419.03
Closing UCC	$ -	$ 630,281.93	$ 855,520.06	$ 740,701.03

UCC - General Equipment

CCA Class 8 (20%)	2007 Estimate	2008	2009	2010
Opening UCC	$ -	$ -	$ -	$ -
Capital Additions Tools & Equipment	$ -	$ -	$ -	$ -
Capital Additions Other Equipment	$ -	$ -	$ -	$ -
UCC Before Half Year Rule	$ -	$ -	$ -	$ -
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ -	$ -
Reduced UCC	$ -	$ -	$ -	$ -
CCA Rate Class 8	20%	20%	20%	20%
CCA	$ -	$ -	$ -	$ -
Closing UCC	$ -	$ -	$ -	$ -