Collus PowerStream
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August 21, 2013

Board Secretary
Ontario Energy Board
PO Box 2319
27th Floor 2300 Yonge Street
Toronto ON M4P 1E4

Attn: Kirsten Walli

RE: Collus PowerStream (ED-2002-0518)
2013 Electricity Distribution Rate Application, EB-2012-0116
Interrogatory Responses

On July 10, 2013, the Board issued Procedural Order No. 1 in the above-captioned proceeding which set out a timetable for interrogatories. Accordingly, Collus PowerStream is submitting responses to the interrogatories that were received from Board Staff and intervenors.

These interrogatory responses have been filed on RESS and two paper copies have been forwarded to the Board Secretary.

If you have any questions please do not hesitate to contact the undersigned at gmcallister@collus.com or (705)445-1800 ext 2274.

Yours truly,

Glen McAllister, B.Sc., CMA
Manager, Billing & Regulatory
Collus PowerStream

Cc: David MacIntosh (by email)
Randy Aiken (by email)
Michael Janigan (by email)
Mark Garner (by email)
Bill Harper (by email)
Wayne McNally (by email)
Mark Rubenstein (be email)
Jay Shepherd (by email)

EB-2012-0116

Ontario Energy Board

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Sched. B, as amended:

AND IN THE MATTER OF an application by Collus PowerStream Corporation for an Order or Orders approving or fixing just and reasonable rates and other service charges for the distribution of electricity, effective September 1, 2013.

COLLUS POWERSTREAM CORP. RESPONSES TO INTERROGATORIES OF BOARD STAFF AND INTERVENORS

August 21, 2013

General

1.0-Staff-1 – Updated RRWF

Upon completing all interrogatories from Board staff and intervenors, please provide an updated RRWF with any corrections or adjustments that the applicant wishes to make to the amounts in the previous version of the RRWF, in the middle column. Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or an explanatory note.

Response

There are no updates to report.

1-SEC-1

Please provide a table showing any adjustment arising from the interrogatory process. This table should include the IR number, application area, description of the change and the impact on the revenue requirement,).

Response

There are no updates to report.

1.0-VECC- 1

Reference: Exhibits All/

Pls. note this interrogatory may be answered in conjunction with 1.0-Staff-3

a) Please provide a tracking sheet (table) showing all adjustments arising from the interrogatories (include Reference IR #.; Item description; area of change, i.e. return on capital/rate base/working capital allowance/amortization/PILS/OM&A/ etc.).

Response

There are no updates to report.

1.0-Staff-2 – Updated Appendix 2-W, Bill Impacts

Upon completing all interrogatories from Board staff and intervenors, please provide an updated Appendix 2-W for all classes at the typical consumption / demand levels (i.e. 800 kWh for residential, 2,000 kWh for GS<50).

Response

There are no updates to report.

1.0-Staff-3 – Updated Revenue Requirement

Upon completion of responses to all interrogatories, please identify any adjustments to the proposed service revenue requirement that the applicant wishes to make relative to the original application.

Response

In response to 8.0-Staff-31 the following changes were made to the Cost of Power calculation:

Change in Cost of Power Impacts ($000)

	Amount	Change (decrease)
Cost of Power - as filed	$ 30,273	
Cost of Power - updated Aug. 21, 2013	$ 29,617	$ (656)
WCA Impact @13%		$ (85)
Revenue Requirement Impact @5.94 cost of capital		$ (5)

Due to the minor change in revenue requirement Collus PowerStream is requesting the changes be made at a later point when the draft rate order is prepared.

Also, 4.0-Staff-26 changes the tax amount by less than $2,000, which is insignificant.

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-Energy Probe-1

Ref: Exhibit 1, Tab 1, Schedule 2

The evidence indicates that the 2013 COS application was filed on April 30, 2013. Please confirm that due to missing information a revised application and evidence was filed on May 24, 2013. Please also confirm that further amendments to the evidence were filed on June 6, 2013.

Response

Collus PowerStream confirms that EB-2012-0116 was filed April 30, 2013. Due to missing information additional evidence was filed May 24, 2013 and a further amendment was filed June 6, 2013.

1.0-Staff-4 – Corporate Organization Chart
Ref: E1/T1/S 12; E1/T1/S 13; E1/T1/S16

In E1/T1/S12, Collus PowerStream provides a summary of the share purchase which was reviewed and approved by the Board in its decision on the MAADs application EB-2012-0056. This transaction resulted in PowerStream Inc. acquiring a 50% equity interest, and the Town of Collingwood retaining a 50% equity interest, reduced from 100%, as result. In E1/T1/S16, Collus PowerStream, states: "The Town of Collingwood is no longer an affiliate of Collus PowerStream as a result of the PowerStream transaction."

Since the Town of Collingwood retains a 50% interest in Collus PowerStream through its shareholding of Collus PowerStream's parent, Collingwood PowerStream Utility Services Corp., why does Collus PowerStream believe that it is no longer affiliated with the Town of Collingwood?

Response:

The Affiliate Relationship Code (ARC) defines an "affiliate", with respect to a corporation, as having the same meaning as in the *Business Corporations Act* (Ontario). Subsections 1(2), 1(4) and 1(5) of the Act provide :

Interpretation: subsidiary body corporate

(2) For the purposes of this Act, a body corporate shall be deemed to be a subsidiary of another body corporate if, but only if,

(a) it is controlled by,

(i) that other, or

(ii) that other and one or more bodies corporate each of which is controlled by that other, or

(iii) two or more bodies corporate each of which is controlled by that other; or

(b) it is a subsidiary of a body corporate that is that other's subsidiary.

Affiliated body corporate

(4) For the purposes of this Act, one body corporate shall be deemed to be affiliated with another body corporate if, but only if, one of them is the subsidiary of the other or both are subsidiaries of the same body corporate or each of them is controlled by the same person. R.S.O. 1990, c. B.16, s. 1 (4).

Control

(5) For the purposes of this Act, a body corporate shall be deemed to be controlled by another person or by two or more bodies corporate if, but only if,

(a) voting securities of the first-mentioned body corporate carrying more than 50 per cent of the votes for the election of directors are held, other than by way of security only, by or for the benefit of such other person or by or for the benefit of such other bodies corporate; and

(b) the votes carried by such securities are sufficient, if exercised, to elect a majority of the board of directors of the first-mentioned body corporate.

As discussed in Exhibit 1, Tab 1, Schedule 12 of the Application, the Town of Collingwood sold a 50% interest in Collingwood Utility Services Corp. (now known as Collingwood PowerStream Utility Services Corp., or "CPUSC"), the parent corporation of Collus PowerStream, to PowerStream Inc. in 2012. Each Shareholder is entitled to nominate and elect the number of directors in proportion to the number of shares owned. The board of directors of consists of 6 directors. The Town of Collingwood nominated 3 directors and PowerStream nominated 3 directors.

Neither the Town of Collingwood nor PowerStream holds voting securities of CPUSC carrying more than 50 per cent of the votes for the election of directors, nor are the votes carried by such securities sufficient, if exercised, to elect a majority of the board of directors.

As a result, neither the Town of Collingwood nor PowerStream controls CPUSC, and neither is an affiliate of Collus PowerStream. In this regard, Collus PowerStream wishes to address an error in Exhibit 1, Tab 1, Schedule 16, page 1 of the Application. At line 7 of that page, PowerStream Inc. is referred to as an affiliate of Collus PowerStream. This is incorrect, as PowerStream Inc. is not an affiliate of Collus PowerStream for the reasons discussed above.

At lines 13 and 14 of that page, Collus PowerStream advised that "The Town of Collingwood is no longer an affiliate of Collus PowerStream as a result of the PowerStream transaction." This statement remains accurate, also for the reasons discussed above.

1-Energy Probe-2

Ref: Exhibit 1, Tab 1, Schedule 12

a) The evidence indicates that no costs associated with the sales transaction have been included in the 2013 revenue requirement. Have any costs, capital, OM&A or other that were incurred in 2012 or previous years been included in the figures provided for those years? If yes, please identify the cost, type of cost and year in which it was incurred.

b) Are any of the costs associated with the Board of Directors of the corporate entities shown on page 2, other than Collus PowerStream Corp. been included in any of the historical data shown for 2012 or previous years, or in the 2013 revenue requirement? If yes, please identify these costs, the amounts and the reasons they are included in the regulated utility costs in a historical, bridge or test year.

Response

a) No "Sales Transaction Costs" (capital, OM&A or other) have been included in the figures provided for 2012 or previous years. All "Sales Transaction Costs" were re-billed to the shareholder, The Town of Collingwood, and reimbursed by them.

In 2012, Collus PowerStream paid some additional general and administrative costs that were not "Sales Transaction Costs", but were incurred as a result of the transaction as follows:

Extra audit for the seven month period ending July 31, 2012 -$31,100.00
Professional accounting fees (dividends/CFO absence) -
$77,923.50
Legal fees for the new Infrastructure Ontario Loan -
$16,775.19
Other non-quantifiable general travel, office, telephone, wages and benefits required to support the transaction process were also incurred.

b) No Board of Director costs of other corporate entities are included in any of the historical data shown for 2012 or previous years, or in the 2013 revenue requirement.

1-SEC-2
[Ex.1/1/13, Ex.2/3/1/p.2]
Please provide all documents and information that was provided to the Board of Directors, in approving this application and the Test Year budget.

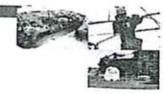
Response

Board Presentation October 29, 2012

Collus PowerStream

Collus PowerStream
Cost of Service Rate Application

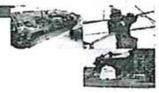
Board of Directors Update
October 29th 2012



COS Application

Objectives
- Full settlement in a Written Hearing
- Substantive approval – OMA & Capital envelopes
- Approval of Key Deliverables:
  - 5-Year Asset Management Plan
  - Reliability & System Expansion targets
  - Customer Service & Safety targets
  - Predictable rate growth
  - Financial targets – ROE, Net Income, Dividends

2



COS Application

Our Challenge

To Strike the appropriate balance

3

COS Application

Strengths
- Vegetation Management
- Customer growth
- System automation - AMI
- Hydro One Supply Infrastructure
- System Reliability
- Customer Mix – e.g. Multi-Unit
- Commercial-Industrial load

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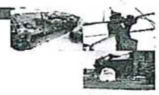

COS Application

Opportunities
- System losses
- Fixed-Variable ratio
- Pole & Conductor Replacement programs
- Shared Services & Synergies

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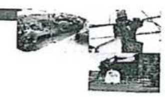
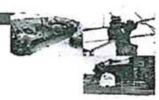


COS Application

Current Status
- Submission is overdue
- Key deliverables:
  - Asset Management Strategy & Plan
  - Load Forecast
  - Cost Allocation
  - COS Application

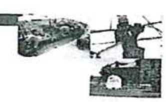
6



COS Application

Challenges
- Alignment
- Preliminary Rate analysis
- Timing:
  - December 2012 – May 2013
  - 2013 ROE
- "Crafting the Story"

7



COS Application

Recommendations
- **Develop** high-quality submission – "Get it right"
- **Deliver** on the Objectives
- **Realize** Synergies & Cost sharing opportunities
- **Recommend** Rate strategy

8

Board Presentation January 21, 2013

Collus PowerStream

Cost of Service Rate Application

Board of Directors Update

January 21, 2013

COS Application

Purpose of Meeting

- To obtain direction for the Collus PowerStream 2013 COS Rate filing
- Agenda:
  - Current Status
  - Challenges
  - Advantages
  - Rate Strategy
  - Rate Impact Scenarios

COS Application

Objectives

- Full settlement in a Written Hearing
- Substantive approval – OM&A & Capital envelopes
- Approval of Key Deliverables:
  - 5-Year Asset Management Plan
  - Reliability & System Expansion targets
  - Customer Service & Safety targets
  - Predictable rate growth
  - Financial targets – ROE, Net Income, Dividends

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COS Application

Progress to Date

- Load Forecast complete – good quality – previous issue
- Asset Management Strategy complete – good quality
- Collus 2013 Budget complete – January 18th
- Ethanol Plant status resolved
- Background data assembled (e.g. Annual Reports) for Application
- EDR model complete - in draft form
- Cost Allocation model complete – in draft form
- Evidence partially drafted

4

COS Application

Current Situation

- OM&A increases - $ 1M over 5 yrs. or 6%/year
- Rate base (Capital Expend.) increases - $ 4M over 5 years – 6%/year
- ROE increases – moving from 4 to 9%
- Forecast Rate increases by customer class:

Class	Distribution	Total Bill
Residential	25 - 35%	4 - 6%
GS < 50kW	10 - 15%	1 - 3%
GS > 50kW	45 - 55%	2 - 4%

5

COS Application

Challenges

- OM&A growth is 6% a year - higher than inflation
- Capital expenditures have increased rate base & depreciation & interest charges
- Increase in Residential rate class due to OM&A (incl. Smart Meters) & ROE increase
- Increase in GS >50kW rate class due to loss of large load
- Errors and omissions in original evidence e.g. Global Adj., Midland
- Transition of knowledge to new staff – Institutional Knowledge
- Data source availability & integrity

6

COS Application

Advantages

- Significant improvements in Load Forecast quality
- Service Level Agreement review in progress - consistent with OEB direction
- Core business is strong – good reliability, safety record & customer service – provides for a "good story"
- Asset Management Plan reaffirms current strategy for OM&A and Capital planning
- While OMA increase is significant it is for "Core Work" - provides basis of defense

COS Application

Application Timing

- Submission is overdue – Status update sent to OEB
- Evidence preparation in progress – First draft complete but gaps in data and explanations remain
- Current forecast filing date early March with rate implementation September 1st
- Risks remain to meeting this date

COS Application

Rate Strategy Objectives

- Approved 2013 levels will be the base for subsequent IRM Applications for up to 5 years
- Base must provide adequate funding for Operations and a commercial return throughout the period
- Base planning assumption - move to maximum ROE in 2013
- Iterative process – PowerStream's "Mock COS Application" exercise

COS Application

Scenarios

- **Base Scenario** – file on current basis
- **S1** - Move to maximum ROE over 5-year period (4 to 9%), reduce OM&A by $ 200k (4%) and phase-in rate increase over 3 years at nominal rate of 2% (Total Bill) to match inflation
- **S2** – Hold ROE at 5% over the 5-year planning period and reduce OM&A by $ 200k (4%)
- **S3** – File COS Application in 2014

COS Application

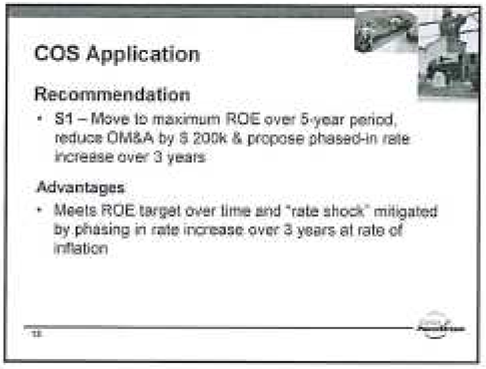
Scenario Results (%)

	Base Case		Phase-in ROE & OMA Cut		Flat ROE & OMA Cut		File COS in 2014	
Rate Impacts	Dist.	TB	Dist.	TB	Dist.	TB	Dist.	TB
Residential	25-35	4-6	20-30	4-6	20-30	4-6	---	---
GS < 50kW	10-15	1-3	10-15	1-2	10-15	1-2	---	---
GS > 50kW	45-55	2-4	40-50	2-4	40-50	2-4	---	---

COS Application

Scenario Analysis

- **Base Scenario** – Meets ROE target but high potential for "rate shock"
- **S1** – Meets ROE target over time and "rate shock" can be mitigated by phasing in over 3 years at nominal rate of 2% (Total Bill) to match inflation
- **S2** – Does not achieve ROE target per Shareholder Agreement
- **S3** – Rate impacts will be higher, with more OMA & Capital spending, but would eliminate 2014 IRM


COS Application
Recommendation
• S1 – Move to maximum ROE over 5-year period, reduce OM&A by $ 200k & propose phased-in rate increase over 3 years
Advantages
• Meets ROE target over time and "rate shock" mitigated by phasing in rate increase over 3 years at rate of inflation

Board Presentation – March 15, 2013

Collus PowerStream

Collus PowerStream
Cost of Service Rate Application

Board of Directors Update

March 15, 2013

COS Application

Purpose of Meeting

- To obtain approval for the Collus PowerStream 2013 COS Rate Application filing
- **Agenda:**
  - Current Status
  - What has Changed ?
  - New Rate Scenarios
  - Recommendation

COS Application

Current Status

Previously

Class	Distribution	Total Bill
Residential	25 - 35%	4 - 6%
GS < 50kW	10 - 15%	1 - 3%
GS > 50kW	45 - 55%	2 - 4%

Now (7% ROE & $ 200k OMA cut)

Class	Distribution	Total Bill
Residential	9.0%	1.6%
GS < 50kW	-16.0%	-2.9%
GS > 50kW	33.3%	1.7%

3

COS Application

What has Changed ?

- Based on finalized OM&A Budget
- Total OM&A increase over 4 years is now $ 725k
- Smart Meter cost recovery is $ 315k & remaining OMA increase of $ 410k is "**program growth**"
- "**Program Growth**" represents only 2.7 % increase per year over 4-year Rebasing Period – consistent with the rate of inflation
- Reflects impact of removal of Rate Riders e.g. GS < 50kV Smart Meters

4

COS Application

What has Changed ?

- Based on 2012 year end actual costs
- Correction of numerous errors and assumptions
- No formal rate mitigation required by OEB – discretionary for the GS > 50kV class at Utility's option
- Total bill impacts now are all within the range of inflation

5

COS Application

New Rate Scenarios

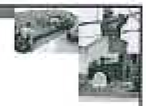
- **S1** – 7% ROE and reduce OM&A by $ 200k
- **S2** – Customized scenario of 7% ROE and $ 147k OM&A reduction to achieve maximum Residential rate increase of 9.9%
- **S3** – 9% ROE and reduce OM&A by $ 200k
- **S4** – 7% ROE and no OM&A reduction
- **S5** – 9% ROE and no OM&A reduction

6

COS Application

Scenario Results (%)

Rate Impacts	7% ROE & - $ 200k Dist.	7% ROE & - $ 200k TB	7.0% ROE & - $ 147k Dist.	7.0% ROE & - $ 147k TB	9% ROE & - $ 200k Dist.	9% ROE & - $ 200k TB	7% ROE & No Cut Dist.	7% ROE & No Cut TB
Residential (14,100 Cust.)	9.0%	1.5%	9.9%	1.7%	12.6%	2.2%	13.3%	2.4%
GS < 50kW (1,700 Cust.)	-15.0	-2.8	-14.2	-2.0	-12.1	-2.4	-12.3	-2.4
GS > 50kW (115 Cust.)	33.3	1.7	34.4	1.8	37.1	1.9	38.0	2.0



COS Application

Scenario Results (%)

Rate Impacts	8% ROE & No Cut Dist.	8% ROE & No Cut TB
Residential (14,100 Cust.)	16.3%	2.9%
GS < 50kW (1,700 Cust.)	-9.6	-1.9
GS > 50kW (115 Cust.)	41.3	2.2

COS Application

Recommendation

- **S4** – 7% ROE and no OMA reduction

Comments

- Attempts to strike a balance between Residential rate increase sensitivities and achievement of Shareholder ROE objectives
- Achieves total bill impacts within the range of inflation
- Maintains but does not maximize the financial health of the utility by starting the IRM period at 7% ROE

8

Board Presentation April 10, 2013

Collus PowerStream

Cost of Service Rate Application

Board of Directors Rate Update

April 10, 2013

COS Application

What has Changed ?

- Changed reference basis for comparison of Customer Bill impacts:
  - Basis of comparison was previously April 30th to September 1st
  - Several substantial Rate Riders expire on April 30th 2013 creating a more favourable basis of comparison for Residential rate impacts
  - Conversely – creates less favourable basis of comparison for GS <50kV rate impacts
  - Basis is now August 31st to September 1st 2013

2

COS Application

What has Changed ?

- Corrected a serious error with respect to line loss rates and the Load Forecast
- Total bill impacts are now within or slightly above the range of inflation

3

COS Application

New Rate Scenarios

- **S1 – Old Basis of Comparison** - 7% ROE and $ 220k OM&A reduction to achieve maximum Residential rate increase of 9.9%
- **S2 – New Basis of Comparison** - 7% ROE and $ 220k OM&A reduction to achieve maximum Residential rate increase of 9.9%
- **S3 – New Basis of Comparison** - 7% ROE and no OM&A reduction
- **S4 – New Basis of Comparison** - 9% ROE and no OM&A reduction

4

COS Application

New Rate Scenarios

- **S5 – New Basis of Comparison** - 9% ROE and $ 147k OM&A reduction
- **S6 – New Basis of Comparison** - 7% ROE and $ 147k OM&A reduction

5

COS Application

Scenario Results (%)

	Old Basis 7% ROE & - $ 220k		New Basis 7.0% ROE & - $ 220k		New Basis 7% ROE & No OMA Cut	
Rate Impacts	Dist.	TB	Dist.	TB	Dist.	TB
Residential (14,100 Cust.)	16.2%	4.2%	9.3%	3.0%	13.5%	3.6%
GS < 50kW (1,700 Cust.)	-7.6	-0.5	11.0	2.6	11.3	2.6
GS > 50kW (115 Cust.)	46.3	3.8	50.8	4.0	55.9	4.3

COS Application

Scenario Results (%)

	New Basis 9% ROE & No OMA Cut		New Basis 9% ROE & - $ 147k		New Basis 7% ROE & - 147k	
Rate Impacts	Dist.	TB	Dist.	TB	Dist.	TB
Residential (14,100 Cust.)	16.5%	4.5%	13.7 %	3.9%	10.7%	3.3%
GS < 50kW (1,700 Cust.)	14.3	3.9	15.5	3.2	12.4	2.7
GS > 50kW (115 Cust.)	59.6	4.8	56.2	4.6	57.5	4.4

Board Presentation April 26, 2013

Collus PowerStream

Cost of Service Rate Application

Board of Directors Rate Update

April 26, 2013

COS Application

Board's Direction to Staff

- Limit Residential Distribution rate increase to a maximum of 9.9%
- Establish an OM&A Budget that satisfies reliability, safety and security objectives and is sufficiently robust to withstand Regulatory review
- Establish Rates which provide for Shareholder Dividends and satisfy Banking Covenants
- Achieve a Return on Equity of 9% (8.98%)

2

COS Application

Customer Bill Impacts (%)

9% (8.985) Return on Equity with no cut to OM & A

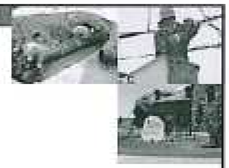
Rate Impacts	Distribution	Total Bill
Residential (14,100 Customers)	7.6 %	2.5 %
GS < 50kW (1,700 Customers)	7.7 %	2.1 %
GS > 50kW (115 Customers)	49.5 %	4.0 %

COS Application

What went wrong and what went right....

1. Line Loss error resulted in overstatement of **Energy Purchases**
2. Correction reduced **Energy Purchases** but **increased Bill impacts**
3. Allocation error of revised **Energy Purchases** to rate/customer classes resulted in understatement of **Energy Purchases** – particularly for Residential class
4. Correction increased **Energy Purchases** and reduced **Bill Impacts**

4



COS Application

Key Planning Assumptions

- Operation Maintenance & Administration Budget - $ 4,755,160
- Return on Equity - 8.98% on a Regulatory basis
- Basis of **Bill Impacts'** Comparison - August 2013 to September 2013
- Rate Effective Date - September 1st 2013

Key Financial Data

Collus PowerStream - Key Financial Data
($'s 000's)

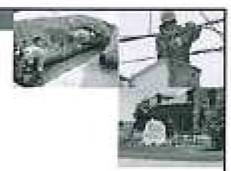
	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Budget	2014 Forecast
Gross Revenue	$ 29,191	$ 31,409	$35,048	$36,444	$39,239	$39,938
Operating Revenue (Distribution + Other)	5,615	5,994	6,016	7,304	6,981	7,037
Operating Programs						
- OM&A	3,915	4,282	4,073	4,843	4,755	4,822
- Capital	3,756	2,095	1,481	1,765	2,023	2,705
Net Income	449	399	468	146	495	643
Dividends	-	-	-	4,364	-	200
Return on Equity	4.3%	3.8%	4.2%	1.0%	6.8%	8.3%
Funds from Operations	$ 1,528	$ 1,563	$ 1,681	$ 2,244	$ 1,674	$ 1,772
Debt Service Coverage Ratio				1.98:1	1.13:1	1.15:1
Debt Capital Ratio				0.61:1	0.59:1	0.60:1
Current Ratio				1.41:1	1.15:1	1.11:1
OM&A per Customer	$ 262	$ 264	$ 264	$ 308	$ 297	$ 294

COS Application

Customer Bill Impacts (%)

9% (8.985) Return on Equity with no cut to OM & A

Rate Impacts	Distribution	Total Bill
Residential (14,100 Customers)	7.6 %	2.5 %
GS < 50kW (1,700 Customers)	7.7 %	2.1 %
GS > 50kW (115 Customers)	49.5 %	4.0 %



COS Application

Customer Bill Impacts (%)

9% (8.985) Return on Equity with $150K cut to OM & A

Rate Impacts	Distribution	Total Bill
Residential (14,100 Customers)	4.5 %	1.9 %
GS < 50kW (1,700 Customers)	5.9 %	1.8 %
GS > 50kW (115 Customers)	45.7 %	3.7 %

Collus PowerStream

Collus PowerStream Corp.
Pro Forma Balance Sheet

as at December 31	2014	2013	2012
Assets	**Projected**	**Projected**	**Actual**
Current			
Cash and bank	$ 2,016,142	$ 2,235,292	$ 4,071,081
Accounts receivable	3,378,589	3,378,589	3,378,589
Unbilled energy revenue	3,135,280	3,135,280	3,135,280
Inventory	309,984	309,984	309,984
Payments in lieu of corporate taxes receivable	-	-	167,266
Prepaid expenses	223,423	223,425	223,423
	9,063,418	9,282,570	11,285,623
Future taxes recoverable	747,617	747,617	747,617
Long-term investments	100	100	100
Property, plant and equipment	17,606,474	16,075,719	15,180,302
Computer software	148,900	95,359	100,440
Regulatory assets	1,165,264	1,165,264	1,144,339
Deferred charges	253,395	321,550	113,105
Goodwill	276,704	276,704	276,704
	$ 29,261,872	$ 27,964,883	$ 28,848,230

Liabilities and Shareholder's Equity			
Current			
Accounts payable and accrued liabilities	$ 6,976,607	$ 6,976,607	$ 6,976,607
Payments in lieu of corporate taxes	150,000	73,876	
Customer deposits and credit balances	650,516	650,516	650,516
Current portion of long-term debt	366,951	360,671	354,628
	8,144,074	8,061,670	7,981,751
Long-term customer deposits	253,862	253,862	253,862
Long-term debt	11,190,180	10,257,131	10,117,802
Employee future benefits	339,774	339,774	336,468
Regulatory liabilities	1,363,189	1,363,189	2,764,077
Deferred program funding	-	161,897	361,897
	21,291,079	20,437,523	21,815,857
Contingencies			
Shareholder's equity			
Share capital	5,101,340	5,101,340	5,101,340
Miscellaneous paid in capital	2,966,014	2,966,014	2,966,014
Deficit	(96,561)	(539,994)	(1,034,981)
	7,970,793	7,527,360	7,032,373
	$ 29,261,872	$ 27,964,883	$ 28,848,230

Collus PowerStream Corp.

Pro Forma Statement of Operations and Deficit

For the year ended December 31	2014	2013	2012
Revenues	**Projected**	**Projected**	**Actual**
Sale of energy	$ 32,901,431	$ 32,415,203	$ 29,120,278
Distribution revenue	6,588,504	5,655,593	5,456,008
Smart meter distribution revenue	-	720,000	1,402,131
Other revenue	448,500	448,500	465,570
	39,938,435	39,239,296	36,443,987
Cost of power purchased	32,901,431	32,415,203	29,120,278
	7,037,004	6,824,093	7,323,709
Operating expenses			
Amortization	913,339	984,220	1,739,853
Billing and collecting	1,174,899	1,151,862	1,218,737
Distribution and transmission	2,216,460	2,173,000	2,100,012
General and administrative	1,430,686	1,398,833	1,491,639
Interest on long-term debt	405,282	445,410	330,323
Interest - other	70,440	70,440	104,044
Other deductions	32,465	31,465	32,918
	6,243,571	6,255,230	7,017,526
Income before taxes	793,433	568,863	306,183
Provision for payments in lieu taxes	150,000	73,876	(19,052)
Future income tax	-	-	179,288
	150,000	73,876	160,236
Net income for the year	643,433	494,987	145,947
Retained earnings (deficit), beginning of year	(539,994)	(1,034,981)	3,183,032
Dividends	200,000	-	4,363,960
Deficit, end of year	$ (96,561)	$ (539,994)	$ (1,034,981)

Collus PowerStream Corp.
Pro Forma Statement of Cash Flows

For the year ended December 31	2014	2013	2012
Cash flows from operating activities	**Projected**	**Projected**	**Actual**
Net income for the year	$ 643,433	$ 494,987	$ 145,947
Adjustments for items not affecting cash:			
Amortization	883,339	954,220	1,739,853
Vehicle amortization, charged to other accts	215,679	192,047	179,188
Employee future benefits	-	3,306	(352)
Future income taxes	-	-	179,288
Loss on Derecognition	30,000	30,000	-
	1,772,451	1,674,560	2,243,924
Changes in non-cash working capital:			
Accounts receivable	-	-	1,980,071
Unbilled energy revenue	-	-	(131,581)
Inventory	-	-	11,815
Prepaid expenses	-	(1)	(103,602)
Accounts payable and accrued liabilities	-	-	948,333
Payments in lieu of corporate taxes	76,124	241,142	(224,108)
Customer deposits and credit balances	-	-	(148,675)
	1,848,575	1,915,701	4,576,177
Cash flows from investing activities			
Purchase of property, plant and equipment	(2,950,157)	(2,268,208)	(2,100,521)
Proceeds from contributed capital	350,000	350,000	339,434
Purchase of computer software	(105,000)	(105,000)	(4,225)
Net decrease in regulatory assets/liabilities	-	(1,457,054)	(1,513,680)
Net decrease from deferred charges	60,000	(216,600)	(23,400)
	(2,645,157)	(3,696,862)	(3,302,392)
Cash flows from financing activities			
Deferred program funding	(161,897)	(200,000)	203,659
Increase (decrease) in lt customer deposits	-	-	(5,787)
Proceeds of long-term debt	1,300,000	500,000	6,300,000
Repayments of long-term debt	(360,671)	(354,628)	(237,740)
Dividends paid	(200,000)	-	(4,363,960)
	577,432	(54,628)	1,896,172
Increase (decrease) in cash during the year	(219,150)	(1,835,789)	3,169,957
Cash and bank, beginning of year	2,235,292	4,071,081	901,124
Cash and bank, end of year	$ 2,016,142	$ 2,235,292	$ 4,071,081

Collus PowerStream Corp.
Notes to Financial Statements
December 31, 2014

34. Capital Disclosures

The corporation considers its capital to be its share capital, miscellaneous paid in capital, and retained earnings. The corporation's main objectives when managing capital are to: i) ensure sufficient liquidity to support its financial obligations and execute its operating and strategic plans, ii) minimize the cost of capital while taking into consideration current and future industry, market and economic risks and conditions, iii) maintain an optimal capital structure that provides necessary financial flexibility while also ensuring compliance with any financial covenants, and iv) provide an adequate return to its shareholders.

The corporation relies predominately on its cash flow from operations to fund its dividend distributions to its shareholders. This cash flow is supplemented, when necessary, through the borrowing of additional debt.

As part of existing debt agreements, financial covenants are monitored and communicated, as required by the terms of credit agreements, on an annual basis by management to ensure compliance with the agreements.

The bank indebtedness covenants require the corporation to maintain a debt to effective equity ratio of 1.50 to 1 or less, a current ratio of 1.25 to 1 or more, and a debt service coverage ratio of at least 1.25 to 1.

The Infrastructure Ontario 4.67% smart meter loan covenants require the corporation to provide notification prior to any new debt issuance and to seek approval where the debt service coverage ratio falls below 1 to 1 at any time; such ratio is otherwise tested and calculated as of the end of each fiscal year. The corporation is also required to maintain a maximum debt to capital ratio of 0.60 to 1 and a minimum current ratio of 1.1 to 1 to be tested and calculated as of the end of each fiscal year.

The Infrastructure Ontario 3.84% recapitalization and working capital loan covenants require the corporation to provide notification prior to any new debt issuance and to seek approval where the debt service coverage ratio falls below 1.15 to 1 at any time; such ratio is otherwise tested and calculated as of the end of each fiscal year. The corporation is also required to maintain a maximum debt to capital ratio of 0.65 to 1 and a minimum current ratio of 1.1 to 1 to be tested and calculated as of the end of each fiscal year.

Management monitors the following key ratios to effectively manage capital:

	2014	2013	2012
	Projected	Projected	Actual
a) Debt Service Coverage Ratio:	1.15:1	1.13:1	1.36:1
b) Debt to Capital:	0.60:1	0.59:1	0.61:1
c) Current ratio:	1.11:1	1.15:1	1.41:1

1-Energy Probe-3

Ref: Exhibit 1, Tab 1, Schedule 16

What is the status of the review of the Service Level Agreements, as noted on page 2? If now available and necessary, please update the application, including the filing of the external study referenced.

Response

On July 22, 2013, Howard Gorman presented for approval to the Board of Directors of the Water Company and Collus PowerStream a report on the cost allocation methodology used to distribute the costs of services provided by Solutions among the businesses to which services are provided. In addition the engagement included a review of the methodology used by the Water Company to charge Collus PowerStream user fees for the building and computer lease.

The cost allocation study is complete and a copy of the report together with an addendum letter dated August 20, 2013 have been included for your reference as Attachment 1.

The Service Level Agreements will be updated based on the study completed. However, these SLA's have not yet been refreshed.

1-Energy Probe-4

Ref: Exhibit 1, Tab 2, Schedule 1

a) Please explain why the savings related to back office support in finance and regulatory processes and the reduction in costs through expertise in the area of regulatory issues and the "soft savings" through the sharing of knowledge and expertise in specialized areas are not quantifiable at this time.

b) When does Collus PowerStream expect to realize quantifiable benefits?

Response

a) The 50% sales transaction between the Town of Collingwood and PowerStream was dated July 31, 2012. However, this transaction did not fully close and the final escrow payment was not released until March 1, 2013. There were seven months over which time financial statements had to be produced, the final dividend calculated and agreed upon, an audit performed, and legal matters resolved before the deal was finalized and closed.

Since that time, staff has been working diligently in many areas to achieve our goal of meeting the service level expectations of our customers today and in the future and as well delivering on our goal of mitigating future costs through synergies with PowerStream. Since the transaction is still very young and since many of the areas being explored have many facets, it is impossible to quantify those savings today.

To date, we have signed a Conservation Service Agreement with PowerStream which will help us deliver our CDM programs better but this agreement is very recent. We have also signed a Master Shared Service Agreement which outlines how future individual service agreements will be managed.

b) The intent of the new relationship is to better deliver what we already do well today and to be prepared for a future customer that has even more expectations of their local distribution company.

As stated, Collus PowerStream believes that our new relationship with PowerStream will assist in future mitigation of upward pressure on distribution rates. We will be looking at all aspects of our business to see where and what we can do to reduce costs or provide for greater customer service. For example, we are hoping in the fall that PowerStream's Control Room will monitor Collus PowerStream's distribution system and dispatch crews when required. This may have additional costs to Collus PowerStream but will provide a greater service to the customers through reduced outages etc.

1-Energy Probe-5

Ref: Exhibit 1, Tab 2, Schedule 1

Collus PowerStream is requesting rates effective September 1, 2013 through April 30, 2014. Is Collus PowerStream requesting recovery of the full $934.3K deficiency over this period or a prorated portion of this amount?

Response:

Collus PowerStream is requesting the full recovery of the amount of $934.3K over this period.

1-Energy Probe-6

Ref: Exhibit 1, Tab 2, Schedule 2

a) Please identify the amount of revenues and expenses that were recorded in 2012 related to smart meter technology and time-of-use billing that were incurred over previous years. Please provide a break out of these revenues and expenses by year in which they were incurred.

b) Does Collus PowerStream have a deferral or variance account for costs associated with moving to IFRS? If yes, please explain why the preparation for the movement to IFRS is listed as a cost driver in 2013 relative to 2009 costs. Please identify the increase in 2013 OM&A costs associated with the preparation for the movement to IFRS that are included in the 2013 revenue requirement.

Response

a) Amount of revenues and expenses that were recorded in 2012 related to smart meter technology and time-of-use billing that were incurred over previous years:

	Accumulated to 2011
Smart Meter Distribution Revenue:	(942,204)
Amortization	448,130
Smart Meter Operation Costs	124,378
Interest	51,299

Break out of these revenues and expenses by year in which they were incurred:

	2006	2007	2008	2009	2010	2011	2012	Total
Smart Meter Distribution Revenue:	(25,919)	(44,438)	(46,914)	(137,601)	(309,280)	(378,052)	(459,927)	(1,402,131)
Amortization			17,864	88,275	157,226	184,765	195,899	644,029
Smart Meter Operation Costs						124,378	199,665	324,044
Interest				12,215	14,322	24,762	12,708	64,007

b) Collus PowerStream has a 1508 deferral account for costs associated with moving to IFRS. The costs authorized for recording in this account are only incremental one-time administrative costs caused by the transition of accounting policies, procedures, systems and processes to IFRS.

Incremental transition costs do not include ongoing IFRS compliance costs, the financial impacts arising from adopting accounting policy changes that reflect changes in the timing of the recognition of income, or costs related to system upgrades, replacements or changes where IFRS was not the major reason for conversion.

In 2013 Collus PowerStream has a change to the useful lives of PP&E and various capital asset policy changes needed to comply with the upcoming switch to IFRS. The on-going tracking, new forms reporting, system set-up, GIS system integration, disposal record keeping, and financial statement reporting create a significant increase in workload and resources of an on-going nature. On January 1, 2015 when Collus PowerStream converts to IFRS these on-going costs will increase even more again.

The initial one-time administrative costs tracked in 1508 are just related to the change in reporting framework. The extra financial burden of increased reporting requirements under IFRS will continue permanently.

The increase in 2013 OM&A costs associated with the preparation for the movement to IFRS that are included in the 2013 revenue requirement is not specifically identifiable. The main accounts impacted are 5615 General and Administrative Salaries and Expenses and 5630 Outside Services.

IFRS accounting changes also impact the ability to burden and capitalize some expenses such as rent and training costs. Account 5096 in Operations is now used for rent of $172,800/yr in 2013 and forward in order to exclude it from the burdens and prevent capitalization of this overhead. Training costs are also excluded from the burden and posted directly to the most applicable O&M account(s).

Previously rent was allocated to the warehouse and garage and a portion of these costs were capitalized to the extent that materials were issued to, and vehicles and equipment were used on capital work orders. Similarly sick, vacation, safety and training time were previously capitalized to the extent that staff worked on capital work orders. These changes have resulted in an increase of approximately $72,000 in amounts in O&M that would have been previously capitalized.

1-Energy Probe-7

**Ref: Exhibit 1, Tab 2, Schedule 2 &
Exhibit 1, Tab 3, Schedule 3**

Please explain and reconcile the different figures shown for 2009 and 2010 in Tables 1 of the above noted exhibits.

Response

	2013	2012	2011	2010	2009	
Billing & Collecting	$1,151,862	$1,218,737	$876,620	$1,154,122	$821,070	
Distribution & Transmission	$2,173,000	$2,100,012	$2,099,480	$1,883,667	$1,903,185	
General & Admin	$1,398,833	$1,491,639	$1,086,626	$1,244,511	$1,190,578	
Donations & LEAP funding	$31,465	$32,918	$10,360	$0	$0	
Total OM&A Per Audited Financial Statements	$4,755,160	$4,843,306	$4,073,086	$4,282,300	$3,914,833	
Less: Misc Gen Expense - UCS Seed Money					-$17,639	Acct 5665
Less: EDA Contingent Liability					-$47,000	Acct 5665
Less: Large Industrial (GS > 50 kW) Bad Debt write off				-$286,449		Acct 6310
Total OM&A per Regulatory	$4,755,160	$4,843,306	$4,073,086	$3,995,851	$3,850,194	

There is a variance to OM&A regulatory because the trial balance in the EDR model (J492) shows $64,640 as “Other Power Supply Expenses” for 2009 and (cell: 0509) shows $286,449 as “Unclassified Expenses” for 2010.

1) The UCS seed money should have been posted to an asset account in 2010 instead of miscellaneous expense because Collus PowerStream provided these funds to UCS for start-up purposes when they became a shareholder. In a subsequent year this amount was actually corrected. It was shown as a credit to miscellaneous expense and then properly debited to an asset account.

2) The EDA contingent liability was recorded in 2009 as a $47,000 expense. In 2010 this was subsequently reversed to 4390 miscellaneous non operating income to adjust for the lawsuit recovery.

3) The Large Industrial (GS > 50 kW) bad debt write off was a loss incurred on the closure of a large industrial customer account.

EXHIBIT 2 - RATE BASE

2-Energy Probe-8

Ref: Exhibit 2, Tab 1, Schedule 1

Please confirm that the bridge year figures for 2012 are all actual figures and not part forecast or preliminary estimates for 2012. If this cannot be confirmed, please update all of the figures in Exhibit 2 to reflect final actual data for 2012.

Response

The bridge year figures for 2012 are all actual figures and not part forecast or preliminary estimates for 2012.

2-Energy Probe-9

Ref: Exhibit 2, Tab 1, Schedule 2

a) **The evidence at page 4 indicates that the rate base for the 2012 Bridge Year is a forecasted increased of $555K over 2011. Please update Tables 4 and 5, if necessary, to reflect actual final figures for 2012.**

b) **Please provide the reference at line 13 of page 4 and lines 8 and 10 of page 5.**

c) **Please explain why Collus PowerStream changed the WCA factor from 15% to 13% for 2012 in the absence of a COS proceeding to set 2012 rates.**

Response:

a) Tables 4 and 5 use 2012 Actual data as indicated in the column headings. On page 4, line 5, the word forecasted should be deleted.

b) Line 13 of page 4 should refer to Exhibit 2, Tab 2, Schedule 1. Line 8 of page 5 should refer to Exhibit 2, Tab 3, Schedule 3. Line 10 of page 5 should refer to Exhibit 2, Tab 2, Schedule 1.

c) Collus PowerStream used a working capital allowance (WCA) factor of 13% for 2012 as this change was announced by the Board in its letter of April 12, 2012. Upon rereading the Board letter, Energy Probe is correct that this change was meant to apply to 2013 COS applications.

   Collus PowerStream notes that this has no effect on the WCA and rate base amounts for the 2013 Test Year and has provided the updated tables below for information only.

   Updated Table 4 and 5 and explanations are provided below to reflect the use of a 15% WCA factor for 2012.

Table EP 9-1: 2012 vs. 2011 Rate Base

Description	2011 Actual CGAAP	2012 Actual CGAAP	Variance
Opening Net Fixed Assets	$ 13,042	$ 13,203	$ 161
Closing Net Fixed Assets	$ 13,203	$ 15,254	$ 2,052
Average Net Fixed Assets	$ 13,122	$ 14,228	$ 1,106
Working Capital Allowance	$ 4,966	$ 5,095	$ 129
Total Rate Base	$ 18,088	$ 19,323	$ 1,235

The 2012 WCA increase of $129,000 is attributable to an increase in OM&A costs of $770,000 and an increase in the cost of power of $88,000.

Table EP 9-2: 2013 vs. 2012 Rate Base

Description	2012 Actual CGAAP	2013 Test Year MIFRS	Variance
Opening Net Fixed Assets	$ 13,203	$ 15,254	$ 2,052
Closing Net Fixed Assets	$ 15,254	$ 16,145	$ 890
Average Net Fixed Assets	$ 14,228	$ 15,699	$ 1,471
Working Capital Allowance	$ 5,095	$ 4,554	$ (541)
Total Rate Base	$ 19,323	$ 20,253	$ 930

An increase in the cost of power of $1,153,000 and a decrease in distribution expenses of $88,000 using a 15% WCA factor would cause an increase in WCA of $160,000. This has been offset by a decrease in WCA of $701,000 due to the change in the WCA factor from 15% to 13%, resulting in a net decrease in WCA of $541,000.

As discussed above and shown in Table EP 9-2, the WCA and rate base amounts for 2013 are unchanged. The change from the previously approved rate base amount to the 2013 test year rate base is unchanged as are the explanations.

2.0-Staff-5

Ref: E1/T2/S6, Appendix A, Revenue Requirement Work Form; Rate Base Tab and E2/T2/S1 p.5, Table 7 and 2013 Fixed Asset Continuity Schedule

Board staff noted that there is a difference of $26,533 between the calculation of the average gross fixed assets in the revenue requirement: rate base tab and the amounts reflected in Table 7 of the 2013 Fixed Asset Continuity Schedule as shown below.

	RRWF: Rate Base Tab	**Calculation based on Fixed Asset Continuity Sch.**	**2013 Fixed Asset Continuity Schedule**	**Difference**
Gross fixed asset (average)	$32,024,061	[$31,038,990 (Bal. 12/31/2012) +$33,062,198 (Bal. 12/31/2013)]/2	$ 32,050,594	**$26,533**
Accumulated depreciation (average)	(16,324,684)	[$15,758,248 (Bal. 12/31/2012) +$16,891,119 (Bal. 12/31/2013)]/2	($16,324,694)	**0**
Net fixed asset (average)	15,699,377		15,725,900	**26,533**

a) Please explain and reconcile the difference noted above and make the necessary adjustment if any, in the evidence.

Response:

a) The Fixed Asset Continuity Schedule (FACS)(Appendix 2-B 2013) has a subtotal line before removal of construction work in progress (CWIP) for calculating gross assets for rate base. The amounts shown above for the FACS are the subtotal line before removal of the CWIP. The total line shows opening gross assets of $31,012,468 and closing gross assets of $33,035,666, for an average of $32,024,062, as used in the rate base calculation and shown on the RRWF.

   No adjustments are required.

2.0-Staff-6

Ref: E2/T2/S1; 2013 Fixed Asset Continuity Schedule; Appendix 2-CI, 2013 Depreciation Expense; E1/T2/S6, Appendix A, Revenue Requirement Work Form; E4/T4/S7, p. 4, Summary of Amortization Expense; PILS WF: Taxable Income-Test Year

Board staff noted the following differences in the 2013 depreciation expenses in the RRWF and the depreciation expenses in the 2013 Appendices 2-B and 2-CI below.

Reference	AMOUNT - $
Appendix 2-B, 2013 Fixed Asset Continuity Schedule, Accumulated Depreciation Additions	$1,102,871
PILS WF: Taxable Income-Test Year Tab, Amortization of Intangibles	$1,102,871
E4/T4/S7, Table 2 Summary of Amortization Expense 2009-2013	$1,102,871
Appendix 2-CI, 2013 Depreciation Expense	$872,860
RRWF: Utility Income Tab	$948,979
RRWF: Revenue Requirement Tab	$948,979

a) Please explain and reconcile the differences in the 2013 depreciation expense found in Appendix 2-B, E4/T4/S7, p.4; PILS WF: Taxable Income-Test Year Tab, Appendix 2-CI and the depreciation found in the RRWF: Utility Income & Revenue Requirement Tabs.
b) Please state which is the correct 2013 depreciation expense and make all the adjustments if any, in the evidence.

Response:

a) All of these numbers are correct, except for the $872,860 as explained below. The differences are explained herein and the numbers reconciled. The accumulated depreciation additions of $1,102,871 correctly represent the depreciation booked for 2013. As shown on Appendix 2-B for 2013, the difference is that $192,047 of depreciation expense is deducted and allocated to the overhead burden pools and shown on other expense lines. As well there is $8,155 of amortization of intangible assets and derecognition expense of $30,000 that must be added to depreciation expense. The end result is the depreciation expense of $948,979 that is included in the revenue requirement. This is summarized in the Table Staff 6-1 below.

Table Staff 6-1: Reconciliation of Depreciation Amounts

Description	Amount
Accumulated Depreciation Additions	$ 1,102,871
Less depreciation expense moved to burden pools and shown on other lines	$ (192,047)
Add amortization of intangible assets	$ 8,155
Net depreciation per Appendix 2-B (2013)	$ 918,979
Add derecognition expense	$ 30,000
Depreciation expense as per RRWF	**$ 948,979**

The full amount of depreciation booked of $1,102,871 is the correct amount to add back on the T2S(1) to arrive at taxable income. For tax purposes it is not relevant some of the depreciation expense is recorded in other OM&A costs; the full depreciation amount needs to be added back.

Exhibit 4, Tab 4, Schedule 7, Table 2 compares the gross depreciation as calculated on the fixed assets and booked to accumulated depreciation. To arrive at the net depreciation expense, similar adjustments to those shown in Table Staff 6-1 above are needed. Table Staff 6-2 below starts with the values shown in E4/T4/S7 Table 2 and shows the adjustments to arrive at depreciation expense used in the revenue requirement calculations.

Table Staff 6-2: Reconciliation of Accumulated Depreciation Additions to Depreciation Expense

	December 31 2009 Act.	December 31 2010 Act.	December 31 2011 Act.	December 31 2012 BY	December 31 2013 TY
Accum. Deprec. Additions	$ 1,033,396	$ 1,150,940	$ 1,197,943	$ 1,888,095	$ 1,102,871
Recorded in Transportation	$ (105,330)	$ (123,587)	$ (152,929)	$ (179,188)	$ (192,047)
Recorded in Communication					
Amortization-deferred charges	$ 8,155	$ 8,155	$ 8,155	$ 8,155	$ 8,155

Amortization of smart meters recorded in account 1555	$ 67,939	$ (67,939)			
Stranded meters after removal				$ 22,791	
Other minor differences		$ (364)			
Depreciation expense	**$ 1,004,160**	**$ 967,205**	**$ 1,053,169**	**$ 1,739,853**	**$ 918,979**

Note: 2013 depreciation expense would also include derecognition expense of $30,000

The depreciation expense of $872,860 shown on Appendix 2-CI for 2013 is an estimate calculated by the worksheet. Collus provided explanations in Appendix 2-C why the estimated depreciation of $872,860 differs from the actual depreciation expense recorded of $1,102,871. The Appendix 2-CI worksheet depreciates the opening net book value over the full useful life of a new asset. The actual depreciation expense calculation correctly uses the remaining useful life to depreciate the opening net book value. Collus adopted IFRS compliant useful lives as of January 1, 2013 as per Board guidance.

b) As explained in part (a) above and shown in Table Staff 6-1, the correct depreciation expense is $948,979. This is the amount used in the calculation of the revenue requirement and no adjustments to the evidence are required.

2-Energy Probe-10

Ref: Exhibit 2, Tab 2, Schedule 1

a) Please confirm that the figures in Table 1 reflect additions closed to rate base in the year. If this cannot be confirmed, please provide a revised Table 1 that reflects only additions closed to rate base in the year.

b) Please confirm that Table 1 reflects actual finalized data for 2012. If this cannot be confirmed, please update Table 1 to reflect actual finalized data for 2012.

c) What is the difference between the capital expenditures shown in Table 2 from the additions shown in Table 1? Is the difference related solely to work in progress? If not, please provide a reconciliation of the figures in Tables 1 and 2.

d) Please explain why the additions shown in Table 1 for 2009 through 2012 do not match the additions shown in the continuity schedules shown in Tables 3 through 6, even though the disposals shown in Table 1 appear to match those shown in Tables 3 through 6.

Response:

a) Confirmed. The additions in Table 1are on an in-service basis and exclude work in progress (“WIP”).

b) Confirmed. The data in Table 1 reflects the 2012 actual audited financial data.

c) The difference between the capital expenditures shown in Table 2 and the additions shown in Table 1 is solely related to work in progress (“WIP”). The purpose of Table 2 is to reconcile the capital expenditures with the additions to fixed assets for the period 2009 to 2013. Table 2 shows that the difference between expenditures and additions is the opening and closing WIP.

d) The reason that the additions in Table 1 do not match the total additions from the Fixed Asset Continuity Schedules (“FACS”) in Tables 3 to 6, is because the FACS include WIP. WIP has been excluded in Table 1 to arrive at additions for rate base purposes. This does not affect disposals as there is no WIP component to disposals.

Table EP 10-1 reconciles the additions totals on Tables 3 to 6 with the additions shown in Table 1.

Table EP 10-1: Fixed Asset Additions to Rate Base vs. FACS Reconciliation

	2009 Act.	2010 Act.	2011 Act.	2012 BY	2013 TY	Total
Additions per Table 1	**$ 1,078,566**	**$ 2,963,250**	**$ 1,358,792**	**$ 4,467,158**	**$ 2,023,208**	**$ 11,890,974**
Per FACS (Tables 3 to 7):						
Cost - Additions	$ 1,621,322	$ 1,930,270	$ 1,480,665	$ 4,371,819	$ 2,023,208	**$ 11,427,284**
Plus opening WIP	$ 490,224	$ 1,032,980	$ -	$ 121,872	$ 26,533	**$ 1,671,609**
Less Closing WIP	$ (1,032,980)	$ -	$ (121,872)	$ (26,533)	$ (26,533)	**$ (1,207,918)**
In-service Additions	**$ 1,078,566**	**$ 2,963,250**	**$ 1,358,793**	**$ 4,467,158**	**$ 2,023,208**	**$ 11,890,975**

2-Energy Probe-11

Ref: Exhibit 2, Tab 2, Schedule 1

a) Please explain why there are no disposals shown for 2013 in Table 7.

b) Please explain the accumulated depreciation disposals that total ($30,000) shown for 2013 in Table 7.

c) If Tables 6 and 7 do not reflect actual finalized figures for 2012, please provide updated tables that do reflect actual finalized figures for 2012.

e) Please provide a table that shows for each of 2009 through 2012 actual along with 2013 forecast, the level of Contributions & Grants received and the gross level of capital expenditures to which those contributions and grants were related. Please explain any significant change in the ratio of these two figures on a year to year basis.

Response:

a) There are no planned disposals for 2013. This is consistent with the 2009 Board Approved amounts. Collus notes the actual at disposals for 2009 were small. Table EP11-1 summarizes the disposal information in Table 7 of E2/T2/S1.

Table EP11-1: Summary of Disposals

Description	December 31 2009 BA	December 31 2009 Act.	December 31 2010 Act.	December 31 2011 Act.	December 31 2012 BY	December 31 2013 TY	2009 Act-2013 Summary
Gross assets at cost Disposals	$ -	$ (24,702)	$ (110,068)	$ (901,611)	$ (1,529,891)	$ -	$ (2,566,272)
Accumulated Depreciation Disposals	$ -	$ 7,063	$ 110,068	$ 901,611	$ 1,002,534	$ (30,000)	$ 1,991,276
NBV Disposals	$ -	$ (17,639)	$ -	$ -	$ (527,357)	$ (30,000)	$ (574,996)

As shown in Table EP11-, the only year with disposals of significant net book value is 2012, which represents the net book value (NBV) of stranded meters transferred to account 1555.

Collus has included a reduction of $30,000 in net book value in 2013 as explained in the response to part (b) below.

b) The estimated NBV of assets that will be derecognized in 2013 is $30,000. This amount has been shown as an increase in accumulated depreciation, under the Disposals column, in Table 7 of E2/T2/S1. This effectively reduces the closing NBV of assets by $30,000 and reduces rate base.

c) Tables 6 and 7 reflect the final audited figures for 2012.

d) Please refer to exhibit 2, tab 3, schedule 7 page 2 of 2. Actual contributed capital for 2008 to 2012 is listed on the bottom of the spreadsheet. The related capital expenditures to which those contributions are related are also listed in this table. Please refer to the line entitled “Misc. Contributed Assets” about half way down the schedule. In addition to this some amounts in services, transformers, and miscellaneous municipal projects may include related capital expenditures.

The total ratio from 2007 to 2012 is $4,441,984 contributed capital / $3,454,619 capital expenditures = 128%. With the inclusion of some services, transformers, and miscellaneous municipal projects to the denominator of the calculation this ratio would be closer to 1:1. Historically, accounting records have not been maintained to provide the total capital expenditures related to the contributed capital.

The 2013 forecasted contributions and grants are listed below. This table was added to the Asset Management Plan before being finalized, but the update was not in the AMP filed with our Cost of Service Application.

Collus PowerStream Asset Management Plan – December 2012

Table 14 – Contributed Capital

DESCRIPTION	2013	2014	2015	2016	2017
OH Conductor and Devices	$122,500	$122,500	$122,500	$122,500	$122,500
Line Transformers	$140,000	$140,000	$140,000	$140,000	$140,000
UG Conductor and Devices	$87,500	$87,500	$87,500	$87,500	$87,500
Subtotal	$350,000	$350,000	$350,000	$350,000	$350,000
Contributed Capital*	($350,000)	($350,000)	($350,000)	($350,000)	($350,000)
Overhead Conductor and Devices	$0	$0	$0	$0	$0

* The amount shown as Contributed Capital is based on historical values.

2-Energy Probe-12

Ref: Exhibit 2, Tab 2, Schedule 1

a) Please explain and show the calculation of the depreciation expense of $58,097.47 shown for 2009 in Table 3 for Meters with a life of 15 years.

b) Please confirm that Collus PowerStream used the full year rule for depreciation of assets added in the test year as part of the 2009 cost of service application. If this cannot be confirmed, what depreciation methodology was used for assets added in the current year as part of the 2009 COS filing?

c) Has Collus PowerStream continued to use the full year rule for depreciation of assets added in each of 2010 through 2012? If not, please explain any changes made and when they were applied.

d) Please explain why there is no depreciation expense (addition to accumulated depreciation) shown for 2010 in Table 4 for the Meters that remained in the category with a life of 15 years after the transfer out of stranded meters.

e) Please explain why stranded meters were moved out of the Meters assets with a life of 15 years in 2009 to a category for stranded meters with an asset life of 25 years in 2010?

f) Please confirm that theses stranded meters were included in rate base and in the revenue requirement approved by the Board for 2009 rates based on a 15 year life. If this cannot be confirmed, please provide evidence from the 2009 proceeding that supported a different life for these meters.

g) Please explain the decrease in the depreciation expense shown in 2012 in Table 6 for stranded meters to $31,907 from $61,082 in 2011.

Response

a) The amortization rate should actually say 25 years for this category in 2009 only. From 2010 forward, after the stranded meters were removed the rate was changed to 15 years for the remaining meters. It appears however this was only an effort to quantify the remaining useful life of the meters left that had already had years of amortization taken. The amortization expense is derived from the following schedule:

	2001	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**Yrly**	**Accum**	**UCC**
	-24373									**Amort**	**Amort**	
	101990	12741	65955	21964	165131	75607	34098	100832	87154			1565562
1998										23755	372996	1192566
1999										27219	421060	1144502
2000										26495	447556	1118007
2001	4070									36387	483942	1081620
2002	3075	501								42364	526307	1039255
2003	3064	510	2643							38707	565014	1000549
2004	3064	510	2638	868						39570	604584	960978
2005	3064	510	2638	879	6611					46192	650776	914787
2006	3064	510	2638	879	6605	3031				49217	699992	865570
2007	3064	510	2638	879	6605	3024	1362			50572	750564	814998
2008	3064	510	2638	879	6605	3024	1364	4040		54614	805178	760384
2009	3064	510	2638	879	6605	3024	1364	4033	3490	58097	863275	702287
2010	3064	510	2638	879	6605	3024	1364	4033	3486	58093	921368	644194
2011	3064	510	2638	879	6605	3024	1364	4033	3486	57309	978677	586885
2012	3064	510	2638	879	6605	3024	1364	4033	3486	56125	1034802	530760
2013	3064	510	2638	879	6605	3024	1364	4033	3486	54288	1089090	476472
2014	3064	510	2638	879	6605	3024	1364	4033	3486	38626	1127716	437846
2015	3064	510	2638	879	6605	3024	1364	4033	3486	34467	1162183	403379
2016	3064	510	2638	879	6605	3024	1364	4033	3486	33372	1195555	370007
2017	3064	510	2638	879	6605	3024	1364	4033	3486	31167	1226722	338840
2018	3064	510	2638	879	6605	3024	1364	4033	3486	30481	1257203	308359
2019	3064	510	2638	879	6605	3024	1364	4033	3486	29289	1286492	279070
2020	3064	510	2638	879	6605	3024	1364	4033	3486	28361	1314853	250709
2021	3064	510	2638	879	6605	3024	1364	4033	3486	28472	1343325	222237
2022	3064	510	2638	879	6605	3024	1364	4033	3486	28312	1371637	193925
2023	3064	510	2638	879	6605	3024	1364	4033	3486	28312	1399949	165613
2024	3064	510	2638	879	6605	3024	1364	4033	3486	25744	1425693	139869
2025	3064	510	2638	879	6605	3024	1364	4033	3486	25603	1451296	114266
2026		510	2638	879	6605	3024	1364	4033	3486	22539	1473835	91727
2027			2638	879	6605	3024	1364	4033	3486	22029	1495864	69698
2028				879	6605	3024	1364	4033	3486	19391	1515255	50307
2029					6605	3024	1364	4033	3486	18512	1533767	31795
2030						3024	1364	4033	3486	11907	1545674	19888
2031							1364	4033	3486	8883	1554557	11005
2032								4033	3486	7519	1562076	3486
2033									3486	3486	1565562	0
2034										0	1565562	0
	77617	12741	65955	21964	165131	75607	34098	100832	87154			

b) Collus PowerStream used the full year rule for depreciation of assets added in the test year as part of the 2009 cost of service application, except for vehicle additions which always used the half year rule.

c) Collus PowerStream continued to use the full year rule for depreciation of assets added in each of 2010 through 2012, except for vehicle additions which always used the half year rule.

Effective January 1, 2013, all additions will be added using the half year rule. The timing of this policy change coincides with the change in useful life of capital assets components and other new capital asset policy standards, such as improved disposal reporting.

d) There is no depreciation expense (addition to accumulated depreciation) shown for 2010 in Table 4 for the Meters that remained in the category with a life of 15 years after the transfer out of stranded meters. From a review of the 2010 amortization schedule for the remaining meters, it is evident that $15,833 was the amount of amortization expense during the year for this category. The column for accumulated depreciation additions and disposals for the meters and stranded meters has the correct overall totals, but the allocation between columns is incorrect.

ORIGINAL

	Accumulated Depreciation				
Description	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
Meters	(863,275.36)		838,775.36	(24,500.00)	213,000.00
Stranded Meters	-	(70,769.93)	(838,775.36)	(909,545.29)	620,346.00
	(863,275.36)	(70,769.93)	-	(934,045.29)	833,346.00

REVISED

	Accumulated Depreciation				
Description	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
Meters	(863,275.36)	(15,833.00)	854,608.36	(24,500.00)	213,000.00
Stranded Meters	-	(54,936.93)	(854,608.36)	(909,545.29)	620,346.00
	(863,275.36)	(70,769.93)	-	(934,045.29)	833,346.00

e) Stranded meters were moved out of the Meter assets with a life of 25 years in 2009 to a category for stranded meters with an asset life of also 25 years in 2010. They were not moved from a 15 year to a 25 year. Please refer to response a) above.

f) The stranded meters were included in rate base and in the revenue requirement approved by the Board for 2009 rates based on a 25 year life. The 25 year life has been continued with no change since this approval.

g) There is a decrease in the depreciation expense shown in 2012 in Table 6 for stranded meters to $31,907 from $61,082 in 2011. Stranded meters were removed from Capital in July 2012. Table 6 reflects seven months of amortization at $4,558.17 per month = $31,907. After the stranded meters were moved to a regulatory account, we continued to amortize them. An additional five months at $4,558.17 per month = $22,790.85 was recorded as amortization expense which reduced the regulatory asset. The total stranded meter amortization expense was $54,698.04, which is comparable to 2011 amortization of $61,082.

<u>2-Energy Probe-13</u>

Ref: Exhibit 2, Tab 2, Schedule 1

a) **Please confirm that computer software and computer equipment were both depreciated over a 3 year period in 2009. If this cannot be confirmed, please explain where computer equipment was recorded for 2009 in Table 3.**

b) **In Table 5 for 2011, computer equipment and computer software are shown as separate line items for the first time. The depreciation rate for computer equipment is shown as 3 years, while there is no period shown for computer software. What period was used in 2011 to depreciation computer software over?**

c) **In Table 6 for 2012, computer software is shown in a depreciation rate based on a 5 year life. Please explain why and when this change occurred.**

d) **Please show the calculation of the depreciation expense of $91,557.80 in 2011 and $91,349.00 in 2012, including all assumptions made for both years.**

e) **Other than changes for computer software and stranded meters, please confirm that Collus PowerStream has not made any changes to depreciation rates from those approved by the Board in the 2009 COS application until those proposed for 2013. If this cannot be confirmed, please provide details of all other changes made through to the end of 2012.**

Response

a) We confirm that computer software was depreciated over a 5 year period in 2009-2013. It appears on the 2009 and 2010 table it shows 3 years, but that is not correct. It was always 5 years.

   There was no computer equipment in 2009.

b) The statement, “In Table 5 for 2011, computer equipment and computer software are shown as separate line items for the first time” is incorrect. This is the first time any computer equipment has been purchased and included as additions in Collus PowerStream capital. Computer equipment is leased and therefore it is rare any computer equipment would be included in PP&E. The small amount of $18k of computer equipment additions in 2011 is amortized over 3 years as indicated on the 2011 – 2013 schedules.

The depreciation rate for computer software continues to be 5 years, even though there is no period shown for computer software on the 2011 schedule.

c) In Table 6 for 2012, computer software is shown in a depreciation rate based on a 5 year life. There was no change. Computer software was depreciated over a 5 year period in 2009-2013. On the 2009 and 2010 table it shows 3 years, but that is not correct. It was always 5 years.

d) Please show the calculation of the depreciation expense of $91,557.80 in 2011 and $91,349.00 in 2012, including all assumptions made for both years.

	2006	2007	2008	2009	2010	2011	2012	YEARLY DEPREC	ACCUM DEPREC	UCC
	53,588	5,265	11,342	398,111	42,022	1,050	4,225			515,603
2006	10,716							10,716	10,716	504,887
2007	10,718	1,053						11,771	22,487	493,116
2008	10,718	1,053	2,270					14,041	36,528	479,075
2009	10,718	1,053	2,268	79,623				93,662	130,190	385,413
2010	10,718	1,053	2,268	79,622	8,405			102,066	232,256	283,347
2011		1,053	2,268	79,622	8,405	210		91,558	323,814	191,789
2012			2,268	79,622	8,404	210	845	91,349	415,163	100,440
2013				79,622	8,404	210	845	89,081	504,244	11,359
2014					8,404	210	845	9,459	513,703	1,900
2015						210	845	1,055	514,758	845
2016							845	845	515,603	-
	$ 53,588	$ 5,265	$ 11,342	$ 398,111	$ 42,022	$ 1,050	$ 4,225			

e) There has never been any change to the five year amortization for computer software in any year.

There has never been a change to the 25 year amortization rate on stranded meters in any year.

Collus PowerStream has not made any changes to depreciation rates from those approved by the Board in the 2009 COS application until those proposed for 2013.

The only minor change occurs in the meter category. From 2010 forward, after the stranded meters were removed the rate was changed to 15 years for the remaining meters with a NBV of only $228,833. It appears however this was only an effort to quantify the remaining useful life of the meters left that had already had years of amortization taken.

2-Energy Probe-14

Ref: Exhibit 2, Tab 2, Schedule 4

Please explain how the figure of $17.6K in decreased amortization costs related to the stranded meters that have been disposed of in 2012 has been calculated (page 3).

Response

The figure of $17.6K in decreased amortization costs (noted on page 3) related to the stranded meters that have been disposed of in 2012 has been calculated as follows:

September	4,405
October	4,405
November	4,405
December	4,405
	17,600

With rates effective September 1st amortization has been stopped on September 1st. Therefore in 2013, the amortization expense is $17,600 less than it would have been if it continued from September to December 2013.
However, the accumulated amortization would not be impacted between Dec 31, 2012 year-end and Dec 31, 2013 year-end because stranded meters were moved to regulatory in July 2012. They no longer had any balance in accumulated amortization in either of these two year-ends.

2-SEC-3

[Ex.2/3/1]
Please provide details of the planned capital expenditures for 2014-2017.

Response

The details of the planned capital expenditures for 2014-2017 are located in our Asset Management Plan Exhibit 2, Tab 3, Schedule 2, Appendix A, Page 33. The pages following the table below describe the various projects to be undertaken over the years.

Table 13 – Capital Expenses

DESCRIPTION	2013	2014	2015	2016	2017
Substation	**$40,000**	**$595,000**	**$1,740,000**	**$40,000**	**$40,000**
Station Equipment	$0	$0	$1,700,000	$0	$0
SCADA	$40,000	$40,000	$40,000	$40,000	$40,000
Land	$0	$550,000	$0	$0	$0
Poles, Towers and Fixtures	**$608,422**	**$601,730**	**$709,255**	**$748,538**	**$954,674**
Overhead Conductor and Devices	**$373,843**	**$133,081**	**$101,552**	**$188,689**	**$160,177**
Primary Conductor	$191,059	$96,405	$90,432	$145,388	$104,405
Secondary Conductor	$7,784	$11,676	$11,120	$43,301	$55,772
Overhead Equipment	$175,000	$25,000	$0	$0	$0
Line Transformer	**$118,564**	**$181,636**	**$282,200**	**$308,328**	**$269,768**
Underground Transformer	$26,404	$125,444	$148,252	$82,792	$114,040
Overhead Transformer	$92,160	$56,192	$133,948	$225,536	$155,728
Underground Conductor and Devices	**$74,879**	**$263,210**	**$227,494**	**$65,485**	**$235,391**
Underground Primary Conductor	$55,379	$163,310	$113,044	$52,285	$144,791
Underground Equipment	$0	$0	$60,000	$0	$0
Trenching	$19,500	$99,900	$54,450	$13,200	$90,600
Meters	**$275,500**	**$275,500**	**$275,500**	**$109,250**	**$109,250**
New Services	**$150,000**	**$150,000**	**$150,000**	**$150,000**	**$150,000**
Other	**$382,000**	**$505,000**	**$240,000**	**$505,000**	**$180,000**
Vehicles and Equipment	$202,000	$325,000	$60,000	$325,000	$0
Tools	$75,000	$75,000	$75,000	$75,000	$75,000
Computer Hardware and Software	$105,000	$105,000	$105,000	$105,000	$105,000
TOTAL	**$2,023,208**	**$2,705,157**	**$3,726,001**	**$2,115,290**	**$2,099,261**

2-SEC-4

[Ex.2/3/1/p.1]
Please provide the expected in-service dates for each Tear Year major capital project

Response

No.	Project Name	Anticipated In-Service Date	Note / Comment
1	Smart Meter - Special Project	31-Dec-13	12 month project
2	Revenue Metering	31-Dec-13	12 month project
3	Hurontario St - Poleline	15-Dec-13	4th Qrt Project
4	Reg 22/04 Infrastructure Compliance	31-Dec-13	12 month project
5	Misc. Road Authority Projects	31-Dec-13	12 month project
6	Simcoe St. - Poleline	1-Jul-13	Completed
7	10th Line - Poleline	15-Dec-13	3rd & 4th Qrt Project
8	Ronell Crs. - u/g	1-May-13	Completed
9	Large Equipment & Vehicles	1-Oct-13	3rd & 4th Qrt Project
10	New Cust. Services	31-Dec-13	12 month project

2.0-Staff-7

Ref: E2/T3/S2, Appendix A – Asset Management Plan
On page 29 of its Asset Management Plan ("AMP"), the following is documented with respect to smart meters:

> **8.3 Smart Meters**
> CPS completed the installation of smart meters throughout the service territory in December 2010. At the end of May 2011 all installed smart meters were registered with the Meter Data Management and Repository ("MDM/R"). Time of use ("TOU") billing began January 1, 2012. Throughout the installation and up to registration with the MDM/R CPS experienced issues with the quality of the meters procured which required the replacement of 839, representing a failure and replacement rate of 5.22% of the total population of installed smart meters.
>
> With smart meters containing not only metrology but also communications and computer technology it can reasonably be assumed that the communications and computer portion of the meters will become obsolete prior to the metrology failing causing the replacement of meters which, from a metrology standpoint, are functioning normally. This is the issue which is currently being experienced with the Sensus iCon F and iCon G model smart meters. The meters, from a metrology standpoint, are accurate. The communications portion of the meter has however become obsolete. CPS has 4,631 Sensus iCon F and iCon G model smart meters which have issues with encryption. Installing encryption on Sensus iCon smart meters is a requirement as a result of the security audit completed in 2012. The 4,631 Sensus iCon F and iCon G model smart meters will need to be replaced with encryption compatible Sensus iCon smart meters.

Table 13 of the Asset Management Plan indicates forecasted meter capex of $275,500 per annum for 2013 to 2015, and $109,250 for each of 2016 and 2017.

Section 10.2.6 of the AMP documents that meter capex is about $109,250 for annual meter replacement for about 600 meters per year, and $166,500 for meter failures, corresponding to about 11% of meters per year.

a) What is the current meter failure rate?
b) Why does Collus PowerStream use a replacement rate of 11% for meter failures?

c) The reduction of meter capex to $109,250 in 2016 and 2017 corresponds to assuming there will be no replacements for meter failures after 2015. Why has Collus PowerStream assumed that replacements for meter failures will cease after 2015?

d) Please identify how the costs for the failed smart meter replacements (both for the meters themselves and for installation/replacement) will be recovered. In other words, were the failed meters replaced under warranty, or were the costs paid for by Collus PowerStream?

i. If the latter, were these costs part of Collus PowerStream's costs reviewed and approved in the utility's smart meter application EB-2012-0017?

ii. Are any of these costs being recovered as part of this 2013 Cost of Service Application? If so identify what the costs are and where they are identified in the Application evidence.

e) With respect to the encryption issues identified for Sensus iCon F and iCon G smart meters:

i. Please document the number of Sensus iCon F and iCon G smart meters for which encryption upgrading is necessary, and the percentage of Collus PowerStream's smart meters that this represents;

ii. Identify what costs Collus PowerStream has estimated for the necessary upgrade. Please identify what costs are identified in the test year in this Application, if applicable, and where these are identified in the Application evidence.

Response

a) To date there has been a total of 157 meter failures in the 2013 (Jan1 to July 31)

Breakdown: First Gen Meters – 96 meters (61.1% of Failures)

5 - Register Reset – After outage the register reset to zero
12 - Radio Failures in the meter
33 - Poor communication – missing interval data
1 - Moisture in meter- caused from ice build up
1 - Damage from falling ice from roof
26 - Excessive Message (units sending out more 120 messages per day)
13 - EEPROM Errors (E1000) this is the electronic chip that calculates usage
2 - Calibration Error, Calibration chip failed
3 - Dead Registers (Display has failed)

Second Gen Meters – 61 meters (38.9% of Failures)

1 - Meter's programming failed
3 - Damage from falling ice from roof
9 - Dead Registers (Display has failed)
1 - Excessive Message (units sending out more 120 messages per day)
1 - Service failure causing the meter to melt
2 - Moisture in meter- caused from ice build up
44 - Radio Failures in the meter

There are 22.4 failures per month so far this year.
The number of Residential meters is about 13,908. This gives us the Failure rate of 1.1% in the first seven months of this year. Using the average of 22.4 per month it's projected that there will be 269 units, this gives us a Failure rate of 1.9% for the year

b) Section 10.2.6 of the AMP indicates a meter replacement rate for failed meters of 11%. The 11% annual replacement is related to the total replacement over 3 years of the iCon F & G meters which represent in total approximately 30% of the total smart meter population.

c) The reduction of the meter capex in 2016 and 2017 is due because the First Generation meters will be fully taken out of service by the end to 2015.

Given that 61.1% of the failures to date in 2013 are related to the First Generation meters and these units will be fully replaced out of our system by 2015 the meter capex valve of $109,250 is to cover the failures of the Second Generation. This valve lower than the valve of $275,500 reported for use in the first three years.

d) These units are outside of the manufacturer's warranty period. Collus PowerStream is requesting a new deferral account, 9.0-Staff-32, to record the costs associated with replacing meters which have become obsolete before their expected retirement date.

i. The replacement of the first generation meters was not anticipated when the smart meter application was filed.
ii. Collus PowerStream has not recorded any costs associated with the replacement of the iCon F&G meters in OM&A. Collus PowerStream is requesting a deferral account as part

of the 2013 Cost of Service application to track the associated costs.

e)

i. The 4,631 Sensus iCon F and iCon G model smart meters will need to be replaced with encryption compatible Sensus iCon smart meters. This will represent 33.3% of Collus PowerStream residential meter population.

ii. Collus PowerStream has budgeted capital costs of $166,250 a year over the next 3 years to replace the iCon F&G meter population. No costs have been included in OM&A.

2.0-VECC – 3

Reference: Exhibit 2, Tab 3, Schedule 2

a) Was an Asset Management Plan undertaken prior to the 2012 Plan? If yes please provide the forecast capital expenditures that were recommended in the prior plan.

b) Was an Asset Management Plan provided in the last cost of service application? If so please provide the recommended forecast capital expenditures from that plan.

c) If no previous plan was undertaken please provide the forecast capital expenditures for 2009 through 2012 that were included in the last cost of service application.

Response

a) Collus PowerStream did not undertake the completion of an Asset Management Plan prior to the 2013 Cost of Service filing.
b) Collus PowerStream did not undertake the completion of an Asset Management Plan prior to the 2013 Cost of Service filing.
c) Collus PowerStream's 2009 cost of service application EB-2008-0226 included capital expenditures for the 2008 bridge year and 2009 test year. See attached schedules.

APPENDIX B 2008 and 2009 - COLLUS Power Corp Capital Budget Summary Schedule

Project/Class No.	Category	Project Description	2008 Budget	[illegible]	UG	[illegible]	2009 Projected	[illegible]	UG	[illegible]
		DISTRIBUTION PLANT - CUSTOMER DEMAND & RENEWAL CATEGORY : Major Construction Projects								
17011	1&2	Parkside Avenue - 4 kV line rebuild project	$120,000.00	$90,000.00	$18,000.00	$12,000.00				
17012	1&2	First Street Rebuild Project- Hurontario to Balsam Street	$110,000.00	$44,000.00	$44,000.00	$22,000.00				
17015	1&2	Creemore Main Street Replacement Project	$50,000.00		$50,000.00	$0.00				
17016	1&2	Sixth Street High to 6th for new Sub. + 2nd Pine to Birch					$330,000.00	$264,000.00	$49,500.00	$16,500.00
17013	1&2	Georgian Trail & Back Lot Project - New Line Installation	$110,000.00	$47,000.00	$35,000.00	$28,000.00	$0.00			
		DISTRIBUTION PLANT - SECURITY & RELIABILITY CATEGORY : Miscellaneous Projects - Resulting from Annual System Inspections (ESA 22/04)								
17016	3	Rebuild Projects (Poles, Conductor & Hardware) Specifically attributed to the Annual Inspections. Note This amount also includes the system inspection costs. (Increase $20,000 in 09)	$100,000.00	$40,000.00	$40,000.00	$20,000.00	$120,000.00	$48,000.00	$48,000.00	$24,000.00
		DISTRIBUTION PLANT - REGULATORY CATEGORY : Distribution System Boundary Line Expansion (Load Transfers Elimination Project)								
17018	6	New 4kV Polelines - Osler Bluff Road, Long Point Road, Madeline Avenue in Collingwood and 10th Line in Thornbury	$100,000.00	$60,000.00	$20,000.00	$20,000.00	$0.00			
17055/7		DISTRIBUTION PLANT - CUSTOMER METERING CATEGORY : Wholesale Metering Capital Projects (2008 and 10)								
	4	The expected upgrade/replacement work that will be required.	$21,000.00				$0.00			
		DISTRIBUTION PLANT - CAPACITY CATEGORY : Distribution Substation Capital Projects								
17040	6	Construction of new MS#8 Sub-Station in the South West Portion of Collingwood as per 2005 System optimization study results updated in 2008 for current situation.	$0.00				$1,800,000.00			
17050		DISTRIBUTION PLANT - CUSTOMER METERING CATEGORY : Electric Metering Capital Projects (Not part of the Provincial Smart Meter Program)								
	4	Annual replacement program for resid. & comm. hydro meters	$60,000.00				$60,000.00			
		DISTRIBUTION PLANT - CUSTOMER DEMAND & RENEWAL CATEGORY : Distribution Transformer Capital Projects								
17070	1&2	To accommodate any new distribution transformers required for general load growth (Add $20,000 in 08 due to supplier inc.)	$100,000.00			$100,000.00	$120,000.00			$120,000.00
		GENERAL PLANT - COMMUNICATIONS EQUIPMENT CATEGORY : SCADA Capital Projects								
17091	13	New RTU's for Sub-Stations, New Data Radios and Fault Indicators for 44kV feeders	$95,000.00				$40,000.00			
		GENERAL PLANT - TRANSPORTATION EQUIPMENT CATEGORY : Large Vehicles & Equipment Purchases								
17126	12	Replace Existing 1973 Forklift	$50,000.00				$0.00			
		Replace Existing Tr 28	$0.00				$100,000.00			
			$0.00				$0.00			
			$0.00				$0.00			
	12	Replace Existing 1992 Double Bucket Truck	$400,000.00				$0.00			
	12	Replace Existing 1998 1/2 Ton Pickup Truck (Locator)	$0.00				$50,000.00			
		DISTRIBUTION PLANT - CUSTOMER DEMAND & RENEWAL CATEGORY : Collingwood - Overhead & Underground Service Capital Projects								
17170,180, 190,200	1&2	Utility spending on any new o/h & u/g residential & general service as per conditions of service or customer request.	$100,000.00	$40,000.00	$40,000.00	$20,000.00	$112,000.00	$44,800.00	$44,800.00	$22,400.00
		DISTRIBUTION PLANT - CUSTOMER DEMAND & RENEWAL CATEGORY : Thornbury - Overhead & Underground Service Capital Projects								
17401-4	1&2	Utility spending on any new o/h & u/g residential & general service as per conditions of service or customer request.	$60,000.00	$24,000.00	$24,000.00	$12,000.00	$64,500.00	$25,800.00	$25,800.00	$12,900.00
		DISTRIBUTION PLANT - CUSTOMER DEMAND & RENEWAL CATEGORY : Clearview - Overhead & Underground Service Capital Projects								
17301-4	1&2	Utility spending on any new o/h & u/g residential & general service as per conditions of service or customer request.	$38,000.00	$15,200.00	$15,200.00	$7,600.00	$71,000.00	$28,400.00	$28,400.00	$14,200.00
		GENERAL PLANT - COMPUTER SYSTEM CATEGORY : CIS & Accounting Enhancements - Specific for COLLUS Power								
17163	11	Enhancements to the customer information system and general accounting system specifically for COLLUS Power. In particular requirements of changes to the electric market.	$400,000.00				$80,000.00			

APPENDIX B 2008 and 2009 - COLLUS Power Corp Capital Budget Summary Schedule

Project or Class No.	Asset Category	[illegible]	2008 Budget	[illegible]	UG	[illegible]	2009 Projected	[illegible]	UG	[illegible]
17500		DISTRIBUTION PLANT - CUSTOMER DEMAND & RENEWAL CATEGORY : Economic Evaluations - Portion paid to developers								
	1&2	The portion paid to developers attributed to their original contributed capital calculations.	$120,000.00	$48,000.00	$48,000.00	$24,000.00	$100,000.00	$40,000.00	$40,000.00	$20,000.00
17130		GENERAL PLANT - FACILITIES CATEGORY : Operations Centre - Capital Additions								
	10	Transformer racking added 09, Office Equipment 2008-10	$85,000.00				$90,000.00			
[illegible]		GROSS TOTAL [illegible]	$2,118,000.00				$3,217,500.00			
N/A		NON-CATEGORY ITEM : Rechargeable Misc Projects & Light Work Re-billed (Not included into totals-used to track utility spending on this non-capital item)								
		Small Misc Projects and other work recorded to track spending	$60,000.00				$60,000.00			
18000		Rechargeable Capital Work : (Used to track utility spending on this item that contributed capital nets against)								
	7	Large Capital Work Projects net impact of $0 to capital	$100,000.00				$100,000.00			
18000		DISTRIBUTION PLANT - CUSTOMER DEMAND & RENEWAL CATEGORY : Contributed Capital (customer portion of utility spending on capital projects listed above)								
	7	Contributions from developers and others for capital work done.	-$350,000.00				-$300,000.00			
(See Schedule B-2 Line 19)		NET CAPITAL SPENDING REQUIREMENT (Net of Contributed Capital)	$1,868,000.00				$3,017,500.00			

	O/H 1	U/G 2	P&T Sub 1&2	Supervisory 3	Meters 4	Transformers 5	Supervisory 6	Vehicles 7	CIS - Software 8	Op Ct - Equip 9	Substation 10	Total
2008												
	$406,200	$334,200	$ 165,600	$21,000	$60,000	$100,000	$95,000	$450,000	$400,000	$95,000		$ 2,118,000
	$ 71,800	$ 15,800	$ (165,600)			$76,000						
	$480,000	$350,000	$ -	$ 21,000	$ 60,000	$ 176,000	$ 95,000	$ 450,000	$ 400,000	$ 65,000	$ -	$ 2,118,000
											Less CC Amt	-$250,000
												$ 1,868,000
2009												
	$451,000	$236,500	$110,000	$0	$60,000	$120,000	$40,000	$160,000	$60,000	$90,000	$1,900,000	$ 3,217,500
	55000	0	-110000			$55,000.00						
	$506,000	$236,500	$ -	$ -	$ 60,000	$ 175,000	$ 40,000	$ 160,000	$ 60,000	$ 90,000	$ 1,900,000	$ 3,217,500
												-$200,000
												$ 3,017,500

2.0-VECC – 4

Reference: Exhibit 2, Tab 3, Schedule 3

a) Please provide the vehicle inventory as of January 1, 2009 and the proposed inventory as of January 1, 2013.

Response

a)

COLLUS POWER CORP
VEHICLE LISTING
2009

Truck 31	1996 Chev	1GCGK24R7TE25497	4584CC	Light	3000	
Truck 25	1995 Ford	1FDKE30F1SHA46386	3071JA	Heavy	4960	
Truck 32	2006 Ford	1FTRX14W16NB29075	9991RR	Light	3000	
Truck 13	1995 Intern	1HTSDAAR7SH669289	NJ2835	Heavy	11800	
Truck 30	1992 Intern	1HTSDPBR2NH401272	XM3538	Heavy	15000	
Truck 29	2010 FRHT	1FVACYDT7AHAP7540	6491XM	Heavy	15909	
Truck 34	2004 GMC	2GTEK19V341146973	WW6770	Light	3000	
Truck 11	2004 Chev Exp	1GCFH25T241200430	WS4035	Light	3000	
Truck 10	2003 Dodge	1D7HG38X73S295372	VJ1020	Light	3000	
Truck 33	1993 Intern	1HTSCPEN7PH493462	EV6602	Heavy	7000	
Truck 26	2003 Chev	1GNDU23E43D207245	AAVC300	Passenger		
Truck 18	2006 International	1HTMKAAR16H208500	JY7447	Heavy	15800	
Truck 36	2006 Dodge Car	1D4GP25R06B559769	AZLS580	Light	3000	LEASED
Truck 14	2004 Ford	1FDAF57P84ED93737	8676TX	Heavy	8000	
Truck 19	2007 Dodge	3D7KS28D87G818383	8829TX	Light	3995	
Truck 12	2008 FRHT	1FVHCYBS48HAB4832	3487WY	Heavy	22730	

Trailers

1988 Home	118998713	C89046	N/A
1987 Home	109704834	C49351	N/A
1982 Home	2041527	K84196	N/A
1969 Home	N69C103	36368F	N/A
1961 Home	153	36369F	N/A
1985 King	2K9P24107EW002641	25148M	N/A
1988 Util	2U9TU4413HW009012	E43125	N/A
2007 Reme	2REA2W7A572Y86578	F7374D	N/A

2.0-VECC – 5

Reference: Exhibit 2, Tab 3, Schedule 3

a) Please provide the annual number of poles replaced between 2007 and 2012 (inclusive) and the proposed pole replacement in 2013 through 2016.

Response

a)

Poles replaced	
Years	# Replaced
2007	200
2008	64
2009	125
2010	130
2011	100
2012	121
To date 2013	65
Per AMP 2013	139
Per AMP 2014	105
Per AMP 2015	158
Per AMP 2016	177

Capital Expenditures

2.0-Staff-8

Ref: E2/T3/S3, table 1 – Capital Expenditure Summary and E2/T3/S7 – Capital Budget

On page 1 of E2/T3/S7 Collus PowerStream states that Table one summarizes Collus PowerStream's actual investments for the years 2009, 2010, 2011, 2012 Bridge and 2013 Test Year. On Table 1 Collus PowerStream only provides its Capital Budget Summary up to 2012 Actual.

a) Please provide the table in the same format with the 2013 forecast amounts as well as 2013 year-to-date spending.
b) Please reconcile the amounts shown for 2009 actual and 2010 actual with Table 1 of E2/T3/S3, p.2 and explain if smart meter capital costs have been included in one of the tables.

Response

a)

COLLUS PowerStream Cap Budget

W.O. #	GL Acct #	DESCRIPTION	2013 FORECAST	2013 YTD June 30th	2013 Remaining
		-			
-	-		-	-	-
DISTRIBUTION PLANT - CUSTOMER DEMAND & RENEWAL CATEGORY:					
	1830/35/45	10th Line 44kV - Poplar to Mt. Road Project	463,301		463,301
17403	1830/35/45	Hurontario Street South 44kV & Overhead	97,120		97,120
17025	1830/35/45	Simcoe St Rebuild - Peel to Raglan	122,766	43,444	79,322
17402	1830/35/45	Ronell Crescent	64,989	74,674	-9,685
DISTRIBUTION PLANT - SECURITY AND RELIABILITY CATEGORY: Misc Projects					
17016	1830-0-0	MISC REBUILD PROJECTS	299,078	191,562	107,516
DISTRIBUTION PLANT - Misc Projects Due to Municipal Development					
17035	1830-0-0	Misc. Municipal Projects 50% Labour& Trucking portion	9,890	7,999	1,891
DISTRIBUTION PLANT - Misc Contributed Capital Projects					
	1830/35/45	Misc Contributed Assets	350,000	60,552	289,448
DISTRIBUTION PLANT - CUSTOMER METERING CATEGORY: Electric Meters					
17050	1860-0-0	Electric Meter Capital	275,500	77,651	197,849
DISTRIBUTION PLANT - CUSTOMER METERING CATEGORY: Electric Meters					

17070	1850-0-0	Distribution Transformer Capital	118,564	33,262	85,302
DISTRIBUTION PLANT - CUSTOMER METERING CATEGORY: Electric Meters					
17091	1980-0-0	SCADA Capital Projects	40,000		40,000
TOOLS AND EQUIPMENT:					
17126		Large Tools, Vehicles & Equipment Purchases (Sections A to D)	252,000		252,000
DISTRIBUTION PLANT - CUSTOMER DEMAND & RENEWAL CATEGORY:					
17170	1855-0-0	New Services - Collingwood	130,000	42,471	87,529
DISTRIBUTION PLANT - CUSTOMER DEMAND & RENEWAL CATEGORY:					
17401	1855-0-0	New Services - Thornbury	5,000	199	4,801
DISTRIBUTION PLANT - CUSTOMER DEMAND & RENEWAL CATEGORY:					
17301	1855-0-0	New Services - Clearview	15,000	2,604	12,396
GENERAL PLANT - COMPUTER SYSTEM CATEGORY - CIS & Accting Systems					
17163	1925-0-0	Customer Information System (CIS) & General Accounting Software	105,000		105,000
GENERAL PLANT - FACILITIES CATEGORY - CAPITAL ADDITIONS					
17131	1915-0-0	Office Equipment (2011 to 2013)	15,000	6,498	8,502
	1955-0-0	Communication Equipment	10,000	6,305	3,695
		Gross Capital Project Spending	2,373,208	547,221	1,825,987
CAPITAL CATEGORY ITEM: RECHARGABLE PROJECTS - CONTRIBUTED CAPITAL					
18500	1995-0-0	CONTRIBUTED CAPITAL	$ (350,000)	(60,552)	$ (289,448)
		Net Capital Spending Projected for the Year	$ 2,023,208	486,669	$ 1,536,539

b) The amounts shown for 2009 and 2010 actual per E2/T3/S3 are $3,755,549 and $2,094,946 respectively. The actual amounts include work-in-progress for smart meters of $2,134,227 and $164,675 respectively. Smart meter costs for 2009 and 2010 should not have been posted to capital work-in-progress. They should have been posted to the 1555 regulatory account. When WIP was closed out in the subsequent year, the smart meter costs did correctly get allocated to 1555.

In order to agree the table to the corporate financial records the line for smart meters work-in-progress was included in Table 1 E2/T3/S3. At the bottom of the table, reconciliation was already provided in the evidence which removes the smart meter work-in-progress. The reconciled amounts for 2009 and 2010 actual are listed as $1,621,322 and $1,930,271 which agrees to E2/T3/S7.

2-Energy Probe-15

Ref: Exhibit 2, Tab 3, Schedule 4

a) Please provide additional information on the lands purchased from CNR. In particular, the size and shape of the land and the Collus PowerStream infrastructure located on the land. For example, is the land an abandoned railway right of way or a former railway yard?

b) Did Collus PowerStream have a right of way on the CNR lands?

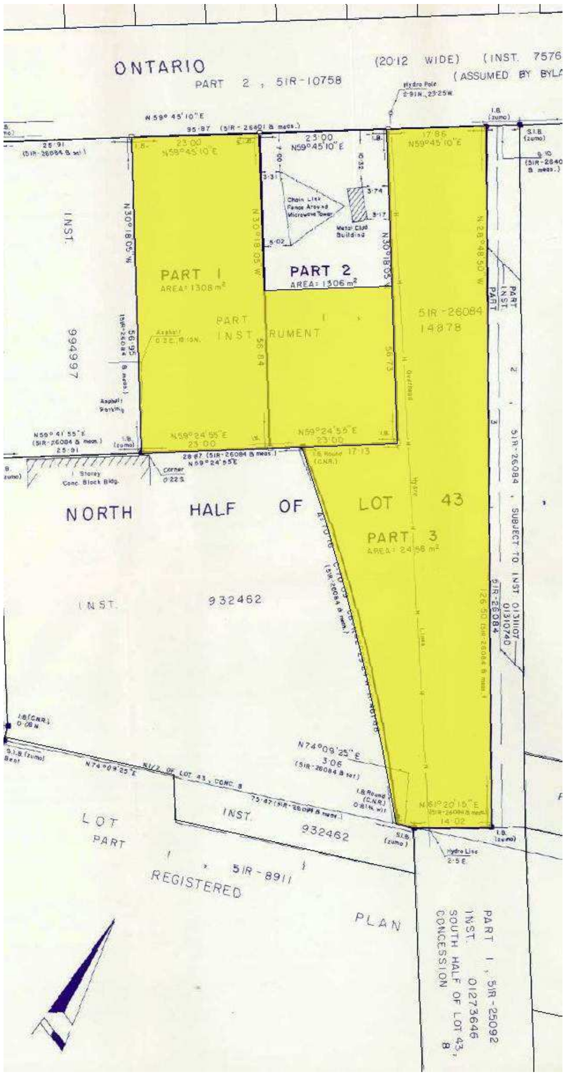
c) Under what authority did CNR have to tell Collus PowerStream to vacate the land or purchase it?

d) Will Collus PowerStream be able to sell any of the purchased land at a future date because all of the land purchased is not needed to ensure access to the infrastructure? If yes, please estimate the percentage of the land purchased that could be sold in the future.

Response

a) The land is a portion of the former CNR Right of Way that was sold approximately 20 years ago to a private Citizen who acquired the parcel to enhance his abutting property when CNR abandoned their Railway service.

This land had an existing utility pole line established approximately 40+ years ago. The pole line has 1- 44kV - 3 Phase circuit and 2 – 4kV - 3 Phase circuits which feeds predominantly the main downtown core of the Town of Collingwood. The purchased lands consist of 5727 m^2.



b) Since the sale to the Private Citizen approximately 20 years ago Collus PowerStream paid annually (vacant land taxes) to retain use of the corridor for the Hydro Right of Way. However, there was no registered easement for the poleline use as the owner did not want an easement registered on title that could encumber his future development concept.

c) CNR did not issue notice to Collus PowerStream to vacate the land rather it was the private land owner who did so through his Lawyer on July 21 2011.

d) Due to size and possible development constraints, it is envisioned that any surplus lands at this location would be a better suited for future relocation of the abutting land-locked Municipal Sub-Station number 1.

<u>2-Energy Probe-16</u>

Ref: Exhibit 2, Tab 3, Schedule 4

a) Are all of the projects shown on pages 19 through 22 included in rate base by the end of 2013?

b) Based on the most recent information available year to date 2013, are all of the projects for 2013 shown on pages 19 through 22 forecast to be completed and in-service by the end of 2013?

Response

a) Yes, all 2013 projects on these pages are included in the 2013 capital budget.

b) All projects on pages 19 through 22 are either completed or substantially underway and still forecasted to be completed / in-service by Year-End.

2-SEC-5
[Ex.2/3/3/4/p.3]
With respect to poll replacement:

a) Please provide the numbers of polls replaced in each year between 2009-2012.

b) Please provide the numbers of polls budgeted to be replaced in the Test Year.

c) Please provide the numbers of polls replaced in the Test Year year-to-date.

Response

a) The chart below indicates the number of hydro poles replaced in each year from 2007 through 2013 year to date. It also shows forecasted hydro pole replacements from 2013 through 2016.

Poles replaced	
Years	# Replaced
2007	200
2008	64
2009	125
2010	130
2011	100
2012	121
To date 2013	65
Per AMP 2013	139
Per AMP 2014	105
Per AMP 2015	158
Per AMP 2016	177

b) See 2-SEC-5 a)
c) See 2-SEC-5 a)

2-SEC-6
[Ex.2/3/4/1-24]
For each major capital project listed, please provide a table comparing budgeted cost with the actual amount spent.

Response

The following table compares budgeted PP&E cost for 2009 – 2012 to actual:

COLLUS Power Capital Budget Summary

W.O. #	GL Acct #	DESCRIPTION	2009 BUDGET	2010 BUDGET	2011 BUDGET	2012 BUDGET	Total	2009 ACTUAL	2010 ACTUAL	2011 ACTUAL	2012 ACTUAL	Total	2009 VARIANCE	2010 VARIANCE	2011 VARIANCE	2012 VARIANCE	TOTAL VARIANCE
DISTRIBUTION PLANT - CUSTOMER DEMAND & RENEWAL CATEGORY																	
17616	1805-0-0	Osler Bluff Road - Hydro One upgrade requirement		25,000			25,000	53,653	45,281			97,934	53,653	20,281	-	-	73,934
17617	1805-0-0	Replace Poles Lobbies					-	17,636				17,636	17,636	-	-	-	17,636
17612	1845-0-0	Hurontario Street Rebuild		100,000	75,000		175,000		24,286	41,643		65,929	-	(75,714)	(33,357)	-	(109,071)
17614		Sixth Street High to 8th for new Sub + Pine to Birch	330,000	200,000			530,000	98,714	217,881	536		317,131	(231,286)	17,881	536	-	(212,869)
17620	1830-0-0	Peel St. (Ont - Hume) & Moberly (Peel - Hume) Rebuild		200,000	165,000		365,000		14,565	147,399		161,964	-	(185,435)	(17,601)	-	(203,036)
17621	1830-0-0	St. Paul Street (Ont - Hume) Rebuild			150,000	147,000	297,000			9,146	119,016	128,162	-	-	(140,854)	(27,984)	(168,838)
17623	1830-0-0	Sixth St Feeder [SS #8 to Walnut Street] Project			100,000		100,000			112,728	148,784	261,480	-	-	12,728	148,784	161,480
17624	1830-0-0	Sixth St Feeder Project Walnut to Oak				100,000	100,000				13,887	13,887	-	-	-	(86,113)	(86,113)
17625	1830-0-0	Simcoe St Rebuild				125,000	125,000				7,696	7,696	-	-	-	(117,304)	(117,304)
DISTRIBUTION PLANT - SECURITY AND RELIABILITY CATEGORY: Misc Projects																	
17619	1830-0-0	MISC. REBUILD PROJECTS	120,000	150,000	350,000	350,000	970,000	157,299	256,163	372,923	337,520	1,123,912	37,299	106,163	22,923	(12,480)	153,912
DISTRIBUTION PLANT - REGULATORY CATEGORY: Hwy System Boundary Line																	
17618	1830-0-0	4th Line @ Blue Mt. Go-Carts Boundary adjustment					-					-	-	-	-	-	-
DISTRIBUTION PLANT - CUSTOMER METERING CATEGORY: Wholesale meters																	
17619	1820-0-0	Wholesale Metering Capital			88,000	50,000	138,000		173,800	109,208		283,708	-	173,800	21,208	(50,000)	145,708
DISTRIBUTION PLANT - Misc Projects Due to Municipal Development																	
17630	1830-0-0	Misc. Municipal Projects 50% Labour& Trucking portion				75,000	75,000				156,080	156,080	-	-	-	81,080	81,080
DISTRIBUTION PLANT - Misc Contributed Capital Projects																	
	1830/30/45	Misc. Contributed Assets					-	1,877,834	232,359	373,508	279,387	2,463,148	1,877,834	232,359	373,508	279,387	2,463,148
DISTRIBUTION PLANT - CAPACITY CATEGORY: Substation Projects																	
1740	1820-0-0	Distribution Station MS 8	1,250,000	550,000			1,800,000	1,099,152	620,452		1,288	1,871,001	(148,606)	(79,548)	-	1,288	(228,999)
17640	1820-0-0	Distribution Station MS Clearview					-				5,000	5,000	-	-	-	5,000	5,000
17641	1885-0-0	Ontario St Load				365,000	365,000			5,000	361,109	366,109	-	-	5,000	1,109	6,109
17642	1855-0-0	MS #7 Repairs - Industrial Park - XMFR Base repair				70,000	70,000				52,410	52,410	-	-	-	(17,590)	(17,590)
17643	1820-0-0	MS #8 Repairs - LT PT Concrete foundation repairs				92,000	92,000				88,328	88,328	-	-	-	(3,672)	(3,672)
17644	1820-0-0	MS7 Incoming Feeder #4kV Metering Relocation					-					-	-	-	-	-	-
DISTRIBUTION PLANT - CUSTOMER METERING CATEGORY: Electric Meters																	
17650	1860-0-0	Electric Meter Capital	60,000	10,000	20,000	65,000	155,000	87,154	29,329	95,647	60,052	262,482	27,154	19,329	75,647	(4,948)	112,482
DISTRIBUTION PLANT - CUSTOMER METERING CATEGORY: Electric Meters																	
17670	1850-0-0	Distribution Transformer Capital	120,000	140,000	175,000	180,000	625,000	372,750	118,453	384,582	113,722	989,507	252,750	(21,547)	219,582	(67,278)	373,507
DISTRIBUTION PLANT - CUSTOMER METERING CATEGORY: Electric Meters																	
17691	1980-0-0	SCADA Capital Projects	40,000	85,000	35,000	55,000	215,000	41,604	62,204	30,298		134,106	1,604	(22,796)	(4,702)	(55,000)	(75,894)
TOOLS AND EQUIPMENT																	
17128		Large Tools, Vehicles & Equipment Purchases (Sections A to D)	150,000	265,000	205,000	242,000	862,000	163,468	283,058	246,672	263,420	956,548	13,468	18,058	41,672	21,420	94,548
DISTRIBUTION PLANT - CUSTOMER DEMAND & RENEWAL CATEGORY																	
17179	1855-0-0	New Services - Collingwood	112,000	100,000	100,000	100,000	412,000	188,100	81,739	90,142	122,660	482,661	76,100	(18,261)	(9,858)	22,660	70,641
DISTRIBUTION PLANT - CUSTOMER DEMAND & RENEWAL CATEGORY																	
17481	1855-0-0	New Services - Thornbury	64,000	25,000	25,000	20,000	134,500	8,169	4,655	4,071	8,930	21,425	(56,831)	(20,345)	(20,929)	(16,070)	(113,075)
DISTRIBUTION PLANT - CUSTOMER DEMAND & RENEWAL CATEGORY																	
17301	1855-0-0	New Services - Clearview	71,000	20,000	20,000	20,000	141,000	6,034	10,848	6,084	12,866	33,832	(64,976)	(14,052)	(20,606)	(7,134)	(107,068)
GENERAL PLANT - COMPUTER SYSTEM CATEGORY - CIS & Accounting Systems																	
17163	1925-0-0	Customer Information System (CIS) & General Accounting Software	60,000	50,000	50,000	50,000	210,000	415,750	42,022	1,050	4,225	463,046	355,750	(7,978)	(48,950)	(45,775)	253,046
GENERAL PLANT - FACILITIES CATEGORY - CAPITAL ADDITIONS																	
17101	1915-0-0	Office Equipment (2011 to 2013)			25,000	50,000	75,000				18,531	18,531	-	-	(25,000)	(31,469)	(56,469)
17165	1920-0-0	Computer Equipment								18,014		18,014			18,014	-	18,014
17166		Transformer Storage Rack System	90,000	30,000			120,000		12,000			12,000	(90,000)	(18,000)	-	-	(108,000)
DISTRIBUTION PLANT - CUSTOMER DEMAND & RENEWAL CATEGORY																	
17600	0	Economic Evaluation Investment	100,000	100,000	100,000	50,000	350,000					-	(100,000)	(100,000)	(100,000)	(50,000)	(350,000)
							-					-	-	-	-	-	-
							-					-	-	-	-	-	-
		Gross Capital Project Spending	2,217,000	2,265,000	1,765,000	2,155,000	8,566,500	4,237,355	2,212,234	2,075,670	2,104,746	10,629,615	1,719,725	7,234	310,670	(54,254)	2,043,415
CAPITAL CATEGORY ITEM: RECOVERABLE PROJECTS - CONTRIBUTED CAPITAL																	
16500	1995-0-0	CONTRIBUTED CAPITAL	(300,000)	(300,000)	(300,000)	(300,000)	(1,200,000)	(2,815,833)	(281,863)	(595,011)	(338,434)	(3,605,341)	(2,315,833)	18,037	(295,011)	(38,434)	(2,633,241)
		Net Capital Spending Projected for the Year	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

This comparison was not initially included in the cost of service application because the historical information was pieced together from various versions of finance historical excel documents that were never trued up to final year-end results. Incomplete information, uncertainty regarding which version was the most current, and a number of repeating carry forward items result in data that is difficult to interrupt in a meaningful way.

The new finance staff have organized quarterly budget to actual review starting in 2013 which will produce more accurate and meaningful reporting for the future.

2-SEC-7

[Ex.2/3/4/p.21]

Please provide a list of the Applicant's current vehicle fleet, with the original in-service date.

Response

COLLUS POWER CORP
2013 VEHICLE LISTING

						Service Date All new unless noted
Truck 13	1995 Intern	1HTSDAAR7SH669289	NJ2835	Heavy	11800	
Truck 30	2010 Intern	1HTWGAAT7AJ247115	2057YJ	Heavy	24000	
Truck 29	2010 FRHT	1FVACYDT7AHAP7540	6491XM	Heavy	15909	
Truck 34	2004 GMC	2GTEK19V341146973	WW6770	Light	3000	
Truck 11	2004 Chev Exp	1GCFH25T241200430	WS4035	Light	3000	
Truck 31	2003 Dodge	1D7HG38X73S295372	VJ1020	Light	3000	
Truck 33	2012 FRHT	1FVHCYBS4CHBK6186	AA83540	Heavy	22730	
Truck 26	2003 Chev	1GNDU23E43D207245	AAVC300	Passenger	3000	
Truck 18	2006 International	1HTMKAAR16H208500	JY7447	Heavy	15800	
Truck 36	2006 Dodge Car	1D4GP25R06B559769	AZLS580	Light	3000	
Truck 14	2004 Ford	1FDAF57P84ED93737	8676TX	Heavy	8000	March 29/07
Truck 19	2007 Dodge	3D7KS28D87G818383	8829TX	Light	3995	
Truck 12	2008 FRHT	1FVHCYBS48HAB4832	3487WY	Heavy	22730	
Truck 32	2006 Ford	1FTRX14W16NB29075	9991RR	Light	3000	
Truck 10	2009 Ford Escape	1FMCU93GX9KA10935	BJTR753	Passenger	3000	Sept 8/10
Truck 16	2011 GMC Ste	1GTN2TEAOBZ252686	7963ZR	Light	3000	
Truck 22	2011 Jeep Compass	1JNF4FB7BD136197	BKTD908	Passenger	3000	

Trailers

1988 Home	118998713	C89046	N/A
1987 Home	109704834	C49351	N/A
1982 Home	2041527	K84196	N/A
1969 Home	N69C103	36368F	N/A
1961 Home	153	36369F	N/A
1985 King	2K9P24107EW002641	K6559S	N/A
1988 Util	2U9TU4413HW009012	K6558S	N/A
2007 Reme	2REA2W7A572Y86578	E7374D	N/A

Net Capital Spending		Less Smart Meters	Adjusted	Average capital spending	
2008	2,610,130	(289,182)	2,320,948		
2009	1,621,322		1,621,322		
2010	1,930,271		1,930,271	1,823,704	(2008-2012)
2011	1,480,665		1,480,665		
2012	1,765,312		1,765,312	1,699,393	(2009-2012)

Projected Capital Spending		Less Creemore Substation	Normalized Capital Spending	Average capital spending	
2013	2,023,208		2,023,208	2,082,783	(2013-2017)
2014	2,705,157	(555,000)	2,150,157		
2015	3,726,001	(1,700,000)	2,026,001		
2016	2,115,290		2,115,290		
2017	2,099,261		2,099,261		

2.0-VECC – 9

Reference: Exhibit 2, Tab 3, Schedule 4

a) COLLUS notes that it has infrastructure on the land it intends to purchase from CNR. Was CNR compensated for this use of this land in the past? If yes please provide the annual amounts for 2009 through 2012. The capital and OM&A costs of the GEA plan for the period 2012 through 2016 (or confirm there are no costs related to the plan).

Response

a) The land is a portion of the **<u>former</u>** CNR Right of Way that was sold approximately 20 years ago to a private Citizen who acquired the parcel to enhance his abutting property when CNR abandoned their Railway service.

Since the sale to the Private Citizen approximately 20 years ago Collus PowerStream paid annually (vacant land taxes) to retain use of the corridor for the Hydro Right of Way. However, there was no registered easement for the poleline use as the owner did not want an easement registered on title that could encumber his future development concept.

2012	1,771.93
2011	1,740.00
2010	1,685.78
2009	1,559.64
2008	1,442.11

This is confirmation that there is <u>NO</u> related GEA plan costs proposed for the period 2012 through 2016

2.0- VECC - 10
Reference: Exhibit 2, Tab 3, Schedule 10, Table 1, pg.2 /Exhibit 4/Tab 4/Schedule 7, pg. 3

a) Please explain the rationale for the variation from the Kinetric recommendation and the COLLUS adopted Useful Life for Overhead Conductors.

b) What would be revenue requirement adjustment if all the useful lives of assets were compliant with the Kinetric recommendations (i.e. elimination of variations shown in Table 1)?

Response

a) In almost all cases Collus PowerStream has selected a useful life for PP&E that is within the range of the kinetric study. The following three components have a slightly different useful life adoption than the kinetric study.

Components:		NEW	OLD	Kinetric	Variance to Kinetric	Variance Explanation
Overhead System	OH Conductor Useful Life (years)	45	25	60	15	OH replaced at the same time as the poles typically
Other Assets	Smart Meters	15	15	5-10	-5	Based on original OEB direction for 15 yr useful life.
Other Assets	System Supervisory Equipment	15	15	20	5	Computerized components would not last 20 years

Exhibit 2, Tab 3, Schedule 10 states, "Overhead conductors have been amortized over 45 years based on the average useful lives of pole assets. COLLUS PowerStream has determined when a pole line is replaced; the existing conductors would be replaced at that time. To do otherwise would result in increased costs due to the fact that two projects would be required - firstly, to install the new poles, remove conductor from old poles and re-install existing conductor to new poles; and secondly, to remove the conductor once again and reinstall new conductor at some future date. Therefore, a typical useful life of 45 years is appropriate for these assets as the two projects would be combined into one."

There is also some additional breakdown in Overhead System from the Kinetrics study to consider. As shown below the typical useful life is 25-60 for the various components within our grouping for overhead system. This supports the 45 year useful life Collus PowerStream has selected.

Current OEB GL Account #	Asset Description	OEB Key Components / Different Asset Types or Subclass (1)	Current OEB Useful Life	Proposed OEB May 2010 Useful Life Range Pa		
				Minimum Useful Life	Typical Useful Life	Maximum Useful Life
1835	OH lines and devices					
		OH conductors	25	50	60	75
		OH line switch	25	30	45	55
		OH line switch motor	25	15	25	25
		OH line switch RTU	25	15	20	20
		OH line integral switches	25	35	45	60
		OH shunt capacitor banks	25	25	30	40
		Reclosures	25	25	40	55

The smart meters are being amortized over a 15 year period as originally outlined by the OEB for the approved length of useful life. Since this time it has become apparent that since these smart meters have significant computerized components, the time frame until obsolete based on the Kinetric study is only 5-10 years. Collus is going to continue to use the recommended 15 year OEB life until more history is available to determine the actual length of service time.

Another area of difference is the System Supervisory Equipment. Considering the number of computerized components in these assets, Collus PowerStream feels a 15 rather than 20 year useful life is a more reasonable estimate based on historical experience with such equipment.

b) The revenue requirement adjustment if all the useful life of assets were compliant with the Kinetric recommendations would result in $4,268 more in amortization expense.

The overhead variance is $0 because based on the components in this group Collus PowerStream is compliant with the Kinetrics study. See table above.

	Actual	Kinetric	Variance
Overhead	112,461	112,461	0
Smart Meters	185,961	181,365	4,597
SCADA	36,287	36,616	(329)
	334,709	330,441	4,268

2-Energy Probe-17

Ref: Exhibit 2, Tab 4, Schedule 1

On page 3 of the evidence it states that the RPP and non-RPP prices are taken from the Ontario Wholesale Electricity Market Price Forecast Report dated March 28, 2013. Table 3 shows a commodity (spot) price of 0.02068 for May, 2013 through October, 2013 and a price of 0.02213 for November and December. In addition, Table 3 shows a Global Adjustment rate of 0.07075 for May, 2013 through October, 2013 and a rate of 0.06176 for November and December. With reference to the above noted Report, please explain where these figures come from.

Response

See revised chart below which corresponds to the reports indicated above.

2013 COP Expense Forecast

Components	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Total
VOLUMES													
Total Purchases (kWh)	31,084,003	*28,198,086*	*28,130,699*	*23,391,114*	*22,406,499*	*22,710,051*	*23,977,523*	*24,375,631*	*22,072,289*	*23,571,977*	*24,822,012*	*29,602,809*	**304,342,694**
RPP Customer Base	51.53%	46.82%	43.38%	41.70%	39.85%	42.46%	50.24%	45.69%	43.48%	46.72%	51.49%	57.63%	
Spot Customer Base	48.47%	53.18%	56.62%	58.30%	60.15%	57.54%	49.76%	54.31%	56.52%	53.28%	48.51%	42.37%	
	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
RPP kWh	16,019,048	13,203,443	12,203,941	9,753,931	8,928,699	9,643,505	12,046,547	11,137,202	9,596,833	11,013,276	12,780,730	17,061,165	**143,388,319**
Non-RPP kWh	15,064,955	14,994,642	15,926,758	13,637,183	13,477,800	13,066,546	11,930,976	13,238,430	12,475,456	12,558,702	12,041,282	12,541,645	**160,954,375**
Historic Ratios (kW)3													
System kW/Energy Purchased kWh - HONI	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%	
System Line/System kW - HONI	8.06%	8.06%	8.06%	8.06%	8.06%	8.06%	8.06%	8.06%	8.06%	8.06%	8.06%	8.06%	
Low Voltage/System kW - HONI	100.04%	100.04%	100.04%	100.04%	100.04%	100.04%	100.04%	100.04%	100.04%	100.04%	100.04%	100.04%	
kW Quantities													
Transmission Network - HONI	57,350	52,025	51,901	43,156	41,340	41,900	44,238	44,973	40,723	43,490	45,796	54,617	**561,508**
Transmission Line - HONI	4,625	4,195	4,185	3,480	3,334	3,379	3,567	3,627	3,284	3,507	3,693	4,404	**45,282**
LV Charges - HONI	57,371	52,044	51,920	43,172	41,355	41,915	44,255	44,989	40,738	43,506	45,813	54,637	**561,715**
RATES													
Commodity (RPP)	0.08069	0.07938	0.07938	0.07938	0.08395	0.08395	0.08395	0.08395	0.08395	0.08395	0.08395	0.08395	**0.08254**
Commodity (Spot)	0.02040	0.02464	0.02464	0.02464	0.01933	0.01933	0.01933	0.01933	0.01933	0.01933	0.01933	0.01933	**0.02075**
Global Adjustment Rate/kWh	0.05381	0.05426	0.04064	0.04064	0.06612	0.06612	0.06612	0.06612	0.06612	0.06612	0.06612	0.06612	**0.05986**
Transmission Network - HONI	3.1800	3.1800	3.1800	3.1800	3.1800	3.1800	3.1800	3.1800	3.1800	3.1800	3.1800	3.1800	**3.1800**
Transmission Line - HONI	0.7000	0.7000	0.7000	0.7000	0.7000	0.7000	0.7000	0.7000	0.7000	0.7000	0.7000	0.7000	**0.7000**
Transmission Transformation - HONI	1.6300	1.6300	1.6300	1.6300	1.6300	1.6300	1.6300	1.6300	1.6300	1.6300	1.6300	1.6300	**1.6300**
LV Charges - HONI	0.6680	0.6680	0.6680	0.6680	0.6680	0.6680	0.6680	0.6680	0.6680	0.6680	0.6680	0.6680	**0.6680**
Wholesale Market Charge (per kWh)	0.0056	0.0056	0.0056	0.0056	0.0056	0.0056	0.0056	0.0056	0.0056	0.0056	0.0056	0.0056	**0.0056**
Monthly Service charges (fixed per account)	292.56	292.56	292.56	292.56	292.56	292.56	292.56	292.56	292.56	292.56	292.56	292.56	**292.56**
LVDS (per kW)	1.9440	1.94	1.94	1.94	1.94	1.94	1.94	1.94	1.94	1.94	1.94	1.94	**1.9440**
COP EXPENSE													
Commodity (RPP)	$ 1,292,577	$ 1,048,089	$ 968,749	$ 774,267	$ 749,564	$ 809,572	$ 1,011,308	$ 934,968	$ 805,654	$ 924,564	$ 1,072,942	$ 1,432,285	**$ 11,824,540**
Commodity (Spot)	1,117,970	1,183,077	1,039,699	890,235	1,151,678	1,116,536	1,019,502	1,131,224	1,066,028	1,073,141	1,028,928	1,071,684	**$ 12,889,702**
Transmission Network - HONI	182,372	165,440	165,044	137,237	131,460	133,241	140,678	143,013	129,499	138,298	145,632	173,681	**$ 1,785,596**
Transmission Line - HONI	3,237	2,937	2,930	2,436	2,334	2,365	2,497	2,539	2,299	2,455	2,585	3,083	**$ 31,697**
Transmission Transformation - HONI	93,480	84,801	84,598	70,345	67,384	68,297	72,108	73,306	66,379	70,889	74,648	89,025	**$ 915,259**
LV Charges - HONI	38,324	34,766	34,683	28,839	27,625	27,999	29,562	30,053	27,213	29,062	30,603	36,497	**$ 375,226**
Wholesale Market Charge	174,070	157,909	157,532	130,990	125,476	127,176	134,274	136,504	123,605	132,003	139,003	165,776	**$ 1,704,319**
Monthly Service charges (8 accounts)	2,340	2,340	2,340	2,340	2,340	2,340	2,340	2,340	2,340	2,340	2,340	2,340	**$ 28,086**
LVDS (on average 2,700 kW)	5,249	5,249	5,249	5,249	5,249	5,249	5,249	5,249	5,249	5,249	5,249	5,249	**$ 62,986**
Total Cost of Power	**$ 2,909,619**	**$ 2,684,608**	**$ 2,460,824**	**$ 2,041,939**	**$ 2,263,111**	**$ 2,292,777**	**$ 2,417,518**	**$ 2,459,195**	**$ 2,228,266**	**$ 2,378,002**	**$ 2,501,931**	**$ 2,979,621**	**$ 29,617,410**

1.0 – VECC – 2

Reference: Exhibit 2, Tab 6, Schedule 1

a) Please provide the causes of interruptions by the following categories (or similar categories if otherwise maintained by COLLUS).

Description	2009 Totals	2010 Totals	2011 Totals	2012 Totals
Scheduled				
Supply Loss				
Tree Contact				
Lightning				
Def. Equip.(other than pole)				
Pole Failure				
Weather				
Human Element				
Animals, Vehicle				
Environment				
Unknown				
Total				

Response

a)

Description	2009 Totals	2010 Totals	2011 Totals	2012 Totals
Scheduled	1		6	30
Supply Loss	8		3	5
Tree Contact	2	4	4	12
Lightning	1	1	4	4
Def. Equip.(other than pole)	20	5	10	26
Pole Failure				
Weather	8	10	6	10
Human Element	(Fire/OPP+1) 4	(Fire/OPP+1) 7	(Fire/OPP) 5	(Fire/OPP+8) 13
Animals, Vehicle				
Environment				
Unknown	2	7	6	21

2.0-VECC – 11

Reference: Exhibit 4, Tab 2, Schedule 2

a) Please confirm that all COLLUS customers are billed monthly. Has the frequency of billing changed since 2009?

Response

a) All Collus PowerStream customers are billed on a monthly basis. Collus PowerStream has not made any changes to billing frequency between 2009 and 2013

2.0-Staff-9

Ref: E9/T1/S1 – Disposition of Renewable Generation and Smart Grid Capital and OM&A Deferral Accounts; Accounting Procedures Handbook FAQ's, dated December 2010.

Collus PowerStream is proposing to dispose December 31, 2011 audited balances (plus interest) in four Renewable Energy/Smart Grid deferral accounts – Accounts 1531, 1532, 1534 and 1535.

a) Were the capital investments and OM&A costs that are the subject of the above noted accounts, reviewed in a prior Board proceeding? If any of the costs (or investments) that are the subject of this disposition request were reviewed by the Board in a previous proceeding, please provide the appropriate references.

Response

a) The capital investment and OM&A costs included in accounts 1531, 1532, 1534 and 1535 were not reviewed in Collus PowerStream's 2009 Cost of Service application EB-2008-0226. With the exception of the balance in account 1531 which was incurred in 2009 the balances in accounts 1532, 1534 and 1535 were incurred in 2010 and 2011 which were subsequent to EB-2008-0226. For reporting purposes, Collus PowerStream included in quarterly RRR.2.1.1 and annual RRR.2.1.7 outstanding balances for recovery in accounts 1531, 1532, 1534 and 1535. Collus PowerStream tracked the carrying charges in accounts 1531, 1532, 1534 and 1535, from inception up to and including disposition of this account with rates effective September 1, 2013. Collus PowerStream is requesting disposition of these accounts at this time.

2.0-Staff-10

Ref: Ex 9/T1/S1/p.11 – Disposition of Account 1531 - Renewable Generation Connection Capital Deferral Account; and Ex 9/T1/S1/p.11 Disposition of Account 1532 Renewable Connection OM&A;

Ontario Regulation 330/09

Distribution System Code, section 3

Under section 3 of the Distribution System Code ("DSC"), distribution system investments related to the connection of renewable generation facilities are classified in the DSC within 3 categories - connection assets, expansions and renewable enabling improvements ("REI"). The cost responsibility for each is also set out in section 3 the DSC

a) Please classify the capital costs in the above noted DSC categories and provide reasoning for the proposed classification. Please provide your response in table format as set out at page 19, section 4.4.2 of the *DSP Filing Requirements*. If the capital investments are classified as REI, please refer to section 3.3.2 of the DSC and demonstrate how the investments qualify as REI investments. In keeping with the DSC, please provide the appropriate cost responsibility for each category.
b) Please explain how the OM&A labour costs were estimated and provide a high-level breakdown of the costs by its main *elements* and a description of the work performed under each *element.*
c) Has Collus PowerStream included any allocation of general expenses that are not specifically related to the eligible investments? If the answer is "yes", please explain why the subject amounts have been included and quantify the amount of general expenses.
d) Please classify the OM&A expenses in the above noted DSC categories and provide reasoning for the proposed classification. Please provide your response in table format as set out at page 19, section 4.4.2 of the *DSP Filing Requirements*. In keeping with the DSC, please identify the appropriate cost responsibility for each category.

As part of its disposition proposal, Collus PowerStream is seeking Board approval to dispose of audited balances (plus interest) in account 1532. Collus PowerStream is proposing to recover the entire amount from its ratepayers and no calculation of direct benefits, has been provided.

Please explain how Collus PowerStream's approach to cost recovery is consistent with the expectations of O.Reg 330/09.

Response

a) Upon review of the balance in account 1531 Collus PowerStream confirms that this balance is not related to Renewable Generation and should have been capitalized in 2009 to account 1845 Underground conductors and devices.
b) The OM&A labour costs were estimated based on the average number of hours spent weekly on the MicroFIT settlement process. When the MicroFIT program was rolled out, Collus PowerStream's settlement process required significant manual intervention to ensure generation data was being accurately communicated and compiled. The MicroFIT settlement process and generation tracking required on average 3 days per week when the MicroFIT program was launched.
c) Collus PowerStream has not allocated any general expenses to account 1532 and account 151 is no longer being requested for disposition. All expenses allocated to account 1532 are directly related to the FIT and MicroFIT settlement process as outlined in 2.0-Staff-10 d).

d) The OM&A costs included in account 1532 represent wages associated with the settlement process of FIT and MicroFIT contracts as assigned by the Ontario Power Authority under the Green Energy and Economies Act. Collus PowerStream uses the Harris CIS system which at present does not have the capability to automate the FIT and MicroFIT settlement process. Collus PowerStream in conjunction with the Utility Collaborative Services, ("UCS"), group have been working towards automating the process however the programming required is extensive and Harris has to date not been able to adequately provide the necessary automated processes. Collus PowerStream continues to work towards automating the process however at this time the settlement process is still manual.
As per the requirements in section 4.4 of the Distribution System Plan, the following information has been provided in respect to the OM&A in account 1532.

- There was no budget specifically prepared for the automation of the FIT and MicroFIT process in the Harris CIS system.
- The OM&A costs being claimed have been specified above.
- Collus PowerStream is requesting disposition of the accumulated costs and interest of $55,818. Collus PowerStream is not requesting the addition of a rate rider or funding adder.
- Not applicable as there is no request for a rate rider or funding adder.

Collus PowerStream is requesting disposition and recovery of the balance in account 1532 from all rate payers. Under the Green Energy and Economies Act Collus PowerStream is required to connect to it distribution grid all eligible MicroFit and FIT generators. All customers throughout Collus PowerStream's service territory have an equal opportunity to benefit from obtaining a MicroFIT or FIT contract. Currently all rate payers are subsidizing the settlement process as the OEB mandated monthly charge of $5.25/generator is not sufficient to cover the monthly costs associated with manually completing the settlement process and subsequent issuance of payment to the generators.

2.0-Staff-11

Ref: Ex 9/T1/S1/p.12 Disposition of Account 1534 – Smart Grid Capital

Collus PowerStream is proposing to dispose audited balances (plus interest) in account 1534. At the above reference, Collus PowerStream states "*this account consists of capital costs associated with investments in a demonstration smart grid project….*"

a) Please provide (i) a description of the demonstration project and its stated purpose and objectives; and, (ii) a description of the technology that was demonstrated.
b) Please provide a breakdown of the capital costs by its main elements, a description of the work performed and need for the capital expenditures.
c) Prior to undertaking its own demonstration project, did Collus PowerStream review other demonstrations related to similar technology?

Response

a) The capital expenditures allocated to this account were not for a demonstration smart grid project. They were related to smart grid studies and education and training.
b)

Account 1534 - Smart Grid Capital		
Year	Cost	Purpose
2010	6,667.75	Mediator for strategic planning session for Collus senior management regarding smart meter deployment and the future of smart grid throughout Collus PowerStream service territory
Account 1535 - Smart Grid OM&A		
2010	10,560.52	Strategic planning session costs (excluding mediator)
	1,695.00	Staff attendance at smart grid summit
	12,255.52	

c) Not applicable

2.0-Staff-12

Ref: Ex 9/T1/S1/p.12 Disposition of Account 1534 – Smart Grid Capital Accounting Procedures Handbook FAQ's, dated December 2010, page 19

Collus PowerStream is proposing to dispose audited balances (plus interest) in account 1534. At the above reference, Collus PowerStream states "… *[this account consists of] capital costs to accommodate renewable generation*".

a) Please provide a description of the noted capital work, a description of need for the capital expenditures and the quantum of the capital costs related to the accommodation of the renewable generation.
b) If the noted capital costs relate to REI investments, the above referenced APH FAQs require that the distributor allocate the related costs to the renewable generation capital account. Based on Collus PowerStream's response to part (a), please undertake the allocation as required under the December 2010 FAQ's.

Response

a) The capital expenditures allocated to this account were not related to the accommodation of renewable generation projects. They were related to smart grid studies, education and training.
b) Not applicable.

2.0-Staff-13

Ref: E9/T1/S1, p. 7, Table 3; E9/T1/S1, p. 12 and December 2010 APH FAQ #16 – Account 1535, Smart Grid OM&A Deferral Account

As per APH FAQ #16 this account only includes OM&A expenses.

Collus PowerStream is seeking disposition of the total balance of $12,808 for Account 1535. Regarding Account 1535, Collus PowerStream indicates that this account consists of **capital** costs including wages, associated with installation, operation and maintenance of smart grid studies, education and training programs.

a) Please confirm that the balances in this account are OM&A cost rather than capital cost. If not, please explain why these expenditures are recorded under on an OMA account and make the necessary adjustment to accounts 1535 and 1534.
b) If yes, please provide a breakdown of these costs.

Response

a) Collus PowerStream confirms the balance in this account is OM&A and is not capital in nature.
b) See 2.0-Staff-11 b) for account breakdown.

EXHIBIT 3 – OPERATING REVENUE

3-Energy Probe-18

Ref: Exhibit 3, Tab 1, Schedule 2

a) For each rate class shown in Table 1, please indicate whether the customers are billed on a monthly or bi-monthly basis.

b) Has there been any change in the billing frequency for any rate class between 2009 and 2013? If yes, please provide details.

Response

a) All Collus PowerStream customers listing Exhibit 3, Table 1, Schedule 2 Table 1 are billed on a monthly basis.

b) Collus PowerStream has not made any changes to billing frequency between 2009 and 2013.

3.0-Staff-14

Ref: E3/T1/S3 and Appendix A – Load Forecast

Board staff's understanding of the multivariate regression model that Collus PowerStream has used to develop its load forecast is as follows:

- The load forecast is developed on a system-purchased kWh basis;
- The monthly measured system purchased kWh was modified by adding back in the loss-adjusted CDM savings for each month in the period from 2006 to 2011. The loss adjustment of CDM is explained on pages 2-4 and summarized in Table 2.
- The system-purchased kWh adjusted to removed loss-adjusted CDM savings was then regressed on the following regressor variables:
  - i. Customer count;
  - ii. Heating Degree Days;
  - iii. Cooling Degree Days; and
  - iv. A full set of binary variables for every month in the year. The full set of monthly variables would have been perfectly linear with an intercept, so the intercept was omitted from the regression.
  - v. The system-purchased kWh was then estimated.
  - vi. Loss-adjusted CDM impacts were then subtracted again to get the estimate or forecast of the "real" system-purchased kWh.
  - vii. Billed system kWh were then calculated by dividing system-purchased kWh by (1 + loss factor).
  - viii. Billed system kWh were then allocated to customer classes based on allocations related to historical data; and
  - ix. For demand-billed customer classes, billed kW were estimated from the classed allocated billed kWh by a kW/kWh conversion factor.

a) Please confirm, correct or provide further explanation of the regression-based approach that Collus PowerStream employed to develop its load forecast.

b) Appendix A and an associated Excel spreadsheet provide the data used for the regression analysis. The CDM variable has been "grossed up" for losses to correspond with the system purchased kWh endogenous variable being modelled. It appears that the CDM variable is held constant in any particular year.
   - i. Please explain the construction of the CDM variable.
   - ii. Please explain the rationale for constant CDM impacts in every month.
   - iii. Please explain how the first-year impact of new CDM programs in a year is accounted for. For example, while OPA program results are reported as annualized amounts, this assumes that all programs are in place as of January 1 of that year. That will not be true for new programs introduced and implemented in that year. In the absence of further information on the timing for deployment and uptake of new programs in a year, a half-year

rule is a better approximation of the real impact on demand. Persistence of CDM programs into future years is appropriately represented by the annualized impacts as reported by the OPA. If Collus PowerStream has not reflected first-year impacts by a "half-year rule", please explain.

c) On page 15 of the exhibit, Collus PowerStream states: "Forecasts are made for time periods beyond the end of the available data. To estimate the average energy purchases for any particular combination of predictor variable values, the values of the predictor variables are simply substituted in the estimated regression equation itself." "Forecasts" for the monthly binary variables are easily understood. Please explain how the forecasts of customer counts, HDD18 and CDD18 were developed.

Response

a) Confirmed
b)
  i.
    Please refer to the table below.

Table:
Derivation of CDM values

Year	1 OPA Programs	2 3rd Tranche	3 Revised CDM Targets 2011-2014	Total CDM Savings	Loss Factor	Loss Factor, kWh Gross-up	CDM Savings, kWh (gross)	Monthly
2005		158,967	0	**158,967**	8.8%	14,037	173,004	14,417
2006	1,031,866	1,236,756	0	**2,268,622**	8.4%	190,111	2,458,733	204,894
2007	2,580,762	436,092	0	**3,016,854**	8.4%	252,812	3,269,666	272,472
2008	3,577,935	220,405	0	**3,798,340**	8.4%	318,301	4,116,641	343,053
2009	5,621,541	0	0	**5,621,541**	7.5%	421,616	6,043,157	503,596
2010	6,099,488	0	0	**6,099,488**	7.5%	457,462	6,556,950	546,412
2011	5,698,064	0	3,194,455	**8,892,519**	7.5%	666,939	9,559,458	796,621
2012	5,615,213	0	2,630,329	**8,245,542**	7.5%	618,416	8,863,958	738,663
2013	5,589,642	0	5,150,426	**10,740,068**	7.0%	751,805	11,491,873	957,656
2014	5,426,277	0	3,994,790	**9,421,067**	7.0%	659,475	10,080,542	840,045
			14,970,000					

The historic and future volume reductions resulting from CDM initiatives were constructed using the following approach:

- The first column of Table 1 provides a summary of persistence kWh from historic OPA programs as provided in the *OPA Report, Section 2.7.10 of Chapter 2 of the Board's "Filing Requirements for Transmission and Distribution Applications", dated June 22, 2011.*

- The second column provides summary kWh for 3rd Tranche PowerStream's programs *(source: PowerStream and former Barrie Hydro Annual CDM Reports for 2005-2008).*

- The third column provides a breakdown of 2011-2014 CDM targets *(source: EB-2010-0215, EB-2010-0216).*

These values were grossed up for losses and annual CDM savings were allocated evenly over the 12 month period for each year. The savings reported by the OPA for programs in the first year they are implemented are the annualized values. The savings achieved count for the whole year, regardless of when the program started.

ii. Annual CDM savings were allocated evenly over the 12 month period for each year for simplicity. The CDM impact is minimal related to the gross load. In addition, the OEB has accepted the use of annualized savings in order to determine LRAM adjustments.

iii. The savings calculated for 2011 are based on OPA actual verified results and are not based on estimated savings. Therefore it is reasonable to attribute 100% of the savings to 2011.

To calculate the forecasted customer growth rate, actual growth by customer rate class was calculated for 2007 through 2011 by customer class and the 5-year average annual growth rate used to forecast the 2012 bridge year and 2013 test year. The annual growth rate was assumed to occur evenly throughout the year.

For purposes of Collus PowerStream's load forecast, weather is not forecasted. Weather inputs are based on monthly normal HDD and CDD data. Collus PowerStream utilizes a simple average of a 10-year (2002 – 2011) weather time series for defining normal weather.

3.0-Staff-15

Ref: E3/T1/S3 – Load Forecast

On page 5, Collus PowerStream documents that the explanatory variable was "monthly system load (i.e. purchases) grossed up by CDM data for January 2005 to September, 2012." This is 93 observations.

Table 8 on page 14 shows that there were 88 observations in the estimated regression model, please confirm the regression range for the model.

Response

The model forecast was based on 88 observations. Five observations were marked off as outliers that contained questionable or erroneous data. These observations were weighted to zero; as a result these observations had no influence on the estimated parameters and on the predicted values for later observations.

In responding to this interrogatory, Collus PowerStream re-estimated the model by utilizing all 93 observations from January 2005 to September 2012. As a result of this re-estimate the Total Energy Purchases forecast for the 2013 Test year is 315,099,814 kWh, which is slightly lower than the filed forecast of 315,834,571 kWh. Given that the reduction in the load forecast is minimal, Collus PowerStream is confident that its original load forecast is valid as filed.

3.0-Staff-16

Ref: Exhibit 3/Tab 1/Schedule 3 – Load Forecast

Collus PowerStream's proposed regression model employs both HDD and CDD and a full set of 12 binary variables for every month in the year. The monthly binary variables will capture seasonal effects which could be weather-related (including HDD and CDD) as well as monthly "seasonal" variations on other factors such as economic activity (e.g. fewer business days in February, holiday impacts in December and January, etc.). The full set of monthly binary variables should be highly correlated with the HDD and CDD variables. Nonetheless, in the estimated coefficients shown in Table 9, all coefficients have t-Statistics that are statistically significant.

a) Why did Collus PowerStream employ two sets of variables (HDD/CDD and the monthly binary variables) that methodologically, would show significant overlap?
b) The use of the monthly binary variables assumes that monthly "seasonal" impact on kWh is constant over years for any particular month. In other words, the seasonal influence for July is 8,012,927 kWh, for every year in the regression range, from 2005 to September 2012. However, normal business cycles, economic and other growth and factors will mean that a constant monthly factor would not be realistic. Please provide Collus PowerStream's reasons for preferring a full set of monthly binary variables to more realistics measures of economic and other drivers, beyond HDD and CDD.

Response

a) The monthly binary variables account for the impact the number of billing days has on the usage (i.e. the more days there are in the billing month, the more energy will be used, holding everything else constant). In virtue of allowing for a different impact every month, the model captures more variation in the data, much more than if simply using a Constant term; this would be effectively the same as assuming a constant number of days in each billing month. While it is possible, let's say that "July" binary variable can take away some of the explanatory variable of the "CDD18", the overlap will be minimal. Below is the correlation matrix that shows the correlation levels between monthly binaries and HDD and CDD variables. In most cases the correlation levels are negligible.

Table:
Correlation Matrix

Variables	HDD18	CDD18
Jan	0.302	0.510
Feb	0.333	0.435
Mar	(0.505)	0.245
Apr	(0.531)	(0.009)
May	0.346	(0.152)
Jun	0.358	(0.312)
Jul	(0.510)	(0.366)
Aug	0.381	(0.361)
Sep	0.396	(0.283)
Oct	(0.517)	(0.115)
Nov	(0.498)	0.055
Dec	0.326	0.379

The best indicator of the robustness of Collus PowerStream's approach is that the coefficients of the binaries and weather variables are all significant. If there was significant overlap, the coefficients on the degree-day variables would not be significant.

b) The impact of the billing days would not typically change significantly over time, seeing how there are only 365 or 366 days in any given year and there is a limited number of ways this can be sliced into billing months. Economic drivers typically do not have pronounced seasonal patterns - in fact, most economic data sources seasonally adjust them if they do. Collus PowerStream utilized a customer count variable as a model driver to account for the impact of economic, while HDD and CDD variables accounted for the weather impact.

3.0-Staff-17

Ref: Exhibit 3/Tab 1/Schedule 3- Load Forecast

On page 11, Collus PowerStream provides, in Table 7, a list of initial explanatory variables tried:

Table 7
Initial Set of Explanatory Variables

Dependent Variable **Independent (Explanatory) Variables**	**Y Monthly Energy Purchases (kWh)** **X1** Heating Degree-days (HDD18) **X2** Colling [sic] Degree-days (CDD18) **X3** Real Gross Domestic Product for Ontario (GDP) **X4** Customer Count for service area **X5** Energy Price **X6** GDP/Energy price (weighted variable) **X7** Simple Trend

a) Why was Real Ontario GDP omitted from the model?
b) What was the definition of Energy Price? Why was this variable omitted from the model?
c) Please explain the rationale underlying the GDP/Energy Price variable? How is this seen as a driver of energy consumption or demand? Why was this variable omitted from the model?
d) Please provide the definition and the purpose underlying the “Simple Trend” variable. Why was this variable omitted from the model?
e) Please explain how these variables were entered in the modelling. Were they entered all and then dropped as a result of a stepwise regression model?
f) What alternative measures of population and/or economic activity were tried? Please summarize why these were not used in the proposed load forecasting equation.

Response

a) The goal of a multiple regression forecast model is to produce the most accurate forecast possible, given available information on the factors that affect monthly energy purchase variation and growth. Several monthly models of energy purchases were specified, estimated and tested to derive the energy purchases forecast. The statistical software generated the coefficients that were used in the variables suitability assessment.

   Collus PowerStream explored commonly-used economic drivers like Ontario Real Gross Domestic Product (GDP). While all model specifications worked well, model using Ontario GDP as a proxy for economic activity did not have a fit that is nearly as strong as that estimated with Customer Count. The GDP model performed worse in the in- and out-of-sample test with out of sample MAPE of 2.18%; this compares with a 1.13% MAPE using the service area customer count.

Table:
Model Comparison (2013 COS Model vs. GDP-based Model)

	Model (Evidence)	Model (GDP)
Adjusted R-Squared	98.70%	94.00%
MAPE, %	1.07%	2.56%
Out-of-Sample MAPE, %	1.13%	2.18%
2013 Test Energy Purchases (kWh)	315,834,571	314,921,272

Model fit with Customer Count proved to be better overall than with Ontario Real GDP and resulted forecasts showed reasonable load growth that is consistent with the historic outcome. Customer Count was selected as the economic driver because of its performance in the model and its ability to be tailored to Collus PowerStream service area.

b) Collus PowerStream explored Energy Pricing as an alternative economic driver. Energy Price variable was constructed using a simple average of the Regulated Price Plan Tier 1 and Tier 2 kWh pricing, historic and forecasted.

While all model specifications had reasonable results, the model using Energy Price variable as a proxy for economic activity did not have a fit that is nearly as strong as that estimated with Customer Count, and the Energy Price model performed worse in the in- and out-of-sample tests.

Table:
Model Comparison (2013 COS Model vs. Energy Price-based Model)

	Model (Evidence)	Model (Energy Price)
Adjusted R-Squared	98.70%	94.50%
MAPE, %	1.07%	2.50%
Out-of-Sample MAPE, %	1.13%	2.21%
2013 Test Energy Purchases (kWh)	315,834,571	315,018,169

c) Given recent economic uncertainty and large swings in recent GDP forecasts, Collus PowerStream considered the GDP/Energy Price variable as an alternative forecast driver.

The load elasticity to price is not well-defined. For non-residential and industrial customers the financial incentives to adjust loads due to high energy prices can be significant, but in the case of residential load, the factors determining the load are more difficult to define. GDP/Energy price weighted variable was developed by assigning a 50/50 weighting of the two variables, Ontario Real GDP and Energy Price.

The model using the weighted economic variable generates the weakest forecast of 313,798 MWHs for 2013 Test Year which is substantially below an average historic growth. Given that the model also performed worse in the in and out-of-sample period, Collus PowerStream decided not to utilize this model for the purpose of forecasting 2013 Test Year load.

Table:
Model Comparison (2013 COS Model vs. GDP/Energy Price-based Model)

	Model (Evidence)	Model (EconVar)
Adjusted R-Squared	98.70%	94.20%
MAPE, %	1.07%	2.44%
Out-of-Sample MAPE, %	1.13%	2.19%
2013 Test Energy Purchases (kWh)	315,834,571	313,797,836

d) Simple trend variable was defined as per following function:
(Year - Base Year) + Period/12

This trend variable served as a proxy for an economic component of the model in the initial stage of the model estimation. Basic model was estimated utilizing weather variables and a Simple Trend variable. However, a trend variable is not a very good way to account for the impact of economics. Most naturally occurring load time series do not behave as though there are straight lines that they are following: real trends change their slopes and/or their intercepts over time. The task was to find the right economic driver of the load time series.

While all model specifications had reasonable results, the model using Trend variable as a proxy for economic activity did not have a fit that is nearly as strong as that estimated with Customer Count, and the Trend model performed worse in the in- and out-of-sample tests.

e) In preparing its load forecast Collus PowerStream looked for patterns in its historical data. Data patterns are represented by historical patterns plus random variation. Random variation cannot be predicted. Historic patterns in load are represented by level (data fluctuates around a constant mean); trend (data exhibits an increasing or decreasing pattern); seasonality (any pattern that regularly repeats itself and is of a constant length); and cycle (for example, patterns created by economic fluctuations). At a minimum, a "best" model should account for these patterns. The objective was to find independent variables that best explain this variation, with a reasonable number of variables with available data as required for forecast periods.

   The task was to find the right economic driver that accounts for the trend pattern. Since all of these variables (Real GDP for Ontario, Energy Price and GDP/Energy Price) are correlated with each other, models were estimated with one variable at a time. Each model was then assessed for its fit and performance in- and out-of-sample.

f) Collus PowerStream explored using local economic drivers to replace Real Gross Domestic Product for Ontario. Local economic data for the Collus PowerStream territory was looked at and considered but was incomplete and did not align with Collus PowerStream's four distinct service territory locations. Building permit data was also looked at and considered but the data was inconsistent and not comparable between the four distinct service territory locations. Collus PowerStream's service territory encompasses four towns: Collingwood, Stayner, Creemore and Thornbury in three municipalities: the Town of Collingwood, Township of Clearview and Town of Blue Mountains, located in two Counties: Simcoe and Grey. No reliable and/or consistent economic or external measure of customer growth, i.e. building permits, data could be identified.

3.0-Staff-18

Ref: Exhibit 3/Tab1/Schedule 3, pp. 3-4 and p. 17-18 and Exhibit 3/Tab 1/Schedule 5/Appendix A – CDM Adjustment

Collus PowerStream has proposed a CDM adjustment of 10,740,068 which represents 34.4% of Collus PowerStream's CDM target. Collus PowerStream has proposed to use the corresponding amount to establish the amount of CDM savings for 2013 (and hence 2014) for the LRAMVA.
Based on the pages from the final 2011 CDM report provided by the OPA for Collus PowerStream as provided in Exhibit 3/Tab 1/Schedule 5/Appendix A, Board staff has prepared the following table, which is also provided in working Microsoft Excel format:
The methodology for this is as follows:
For the top table

- The 2011-2014 CDM target is input into cell B4;
- Measured results for 2011 CDM programs for each of the years 2011 and persistence into 2012, 2013 and 2014 are input into cells C13 to F13;
- Based on these inputs, the residual kWh to achieve the 4 year CDM target is allocated so that there is an equal incremental increase in each of the years 2012, 2013 and 2014.

Load Forecast CDM Adjustment Work Form (2013)

Collus PowerStream Power Corp. ***EB-2012-0116***

		4 Year (2011-2014) kWh Target:			
		14,970,000			
	2011	2012	2013	2014	Total
		%			
2011 CDM Programs	5.48%	5.48%	5.48%	4.94%	21.38%
2012 CDM Programs		13.10%	13.10%	13.10%	39.31%
2013 CDM Programs			13.10%	13.10%	26.21%
2014 CDM Programs				13.10%	13.10%
Total in Year	**5.48%**	**18.58%**	**31.69%**	**44.26%**	**100.00%**
		kWh			
2011 CDM Programs	820,000	820,000	820,000	740,000	3,200,000
2012 CDM Programs		1,961,667	1,961,667	1,961,667	5,885,000
2013 CDM Programs			1,961,667	1,961,667	3,923,333
2014 CDM Programs				1,961,667	1,961,667
Total in Year	**820,000**	**2,781,667**	**4,743,333**	**6,625,000**	**14,970,000**
				Check	14,970,000

	Net-to-Gross Conversion "Gross"	"Net"	Difference	"Net-to-Gross" Conversion Factor ('g')
2006 to 2011 OPA CDM programs: Persistence to 2013	1	1	-	0.00%

	2011	2012	2013	2014	Total for 2013
Amount used for CDM threshold for LRAMVA	820,000	1,961,667	1,961,667		4,743,333
Manual Adjustment for 2013 Load Forecast	410,000	1,961,667	980,833		3,352,500
Manual adjustment uses "gross" versus "net" (i.e. numbers multiplied by (1 + g)	*50% assumed to be in base forecast, so 50% needed for full year persistence by 2014*		*Only 50% of 2013 CDM impact is used based on a half year rule*		

The second table is to calculate the conversion from “net” to “gross” results. While the LRAMVA is based on the “net” OPA-reported results, the load forecast is impacted also by CDM savings of “free riders” and “free drivers”. While Board staff has input values of “1” in each of cells D24 and E24, in the absence of other information, these should be populated with the measured “gross” and “net” CDM savings for the persistence of all CDM programs from 2006 to 2011 on 2013, as reported in the final OPA reports.

For the last table, two numbers are calculated:

- The “Amount used for CDM threshold for LRAMVA” is the sum of the persistence of 2011 and 2012 CDM programs and the annualized impact of 2013 CDM programs on 2013; and
- “Manual Adjustment for 2013 Load Forecast” represents the amount to be reflected in the 2013 load forecast. This amount uses the “gross” impact, which is calculated by multiplying each year’s CDM program impact or persistence by (1 + g) from the second table. In addition, the impact of the 2013 CDM programs on 2013 “actual” consumption is divided by 2 to reflect a “half year” rule. Since the 2013 CDM programs are not in effect at midnight on January 1, 2013, the “annualized” results reported in the OPA report will overstate the “actual” impact. In the absence of information on the timing and uptake of CDM programs in their initial year, a “half-year” rule may proxy the impact.

a) Please provide the preliminary 2012 CDM report from the OPA for Collus PowerStream. This is normally provided in the spring of the year. If this is not available, please explain.
b) Please input the “gross” and “net” cumulative kWh CDM savings from all CDM programs from 2006 to 2011 on 2013 as measured in the final OPA reports into, respectively, cells D24 and E24. Please verify the inputs and results of the model.
c) Please derive the class CDM kWh and kW savings that would correspond with the “net” CDM savings above.
d) Since Collus PowerStream has calculated its forecast on a system purchased kWh model, the CDM adjustment should be similarly adjusted for losses. When the forecast is then calculated on a billed basis to again back out the losses, and allocated to classes for class-specific consumption (and converted to kW demand for demand-billed customer classes) and used in cost allocation and as billing determinants for volumetric based distribution rates and other volumetric rate riders and rate adders. Please provide Collus PowerStream’s views as to whether this is preferable to the approach that it has proposed in the Application.
e) Please provide Collus PowerStream’s comments on the methodology above to develop the CDM savings that will underlie the 2013 CDM amount for the LRAMVA and the corresponding CDM adjustment for the 2013 test year load forecast. What, if any, refinements to this approach should be considered?

Response

a)

saveONenergy

Message from the Vice President:

The OPA is pleased to provide the enclosed Draft 2012 Results Report. This report is designed to provide preliminary information on the 2012 results and to help populate LDC annual report templates that will be submitted to the OEB in late September.

Please note that the 2012 draft results within this report may vary from the Q4 2012 preliminary report for the following reasons:

- The submission of updated data by the LDCs into the iCon CRM by May 24, 2013 allowed the evaluators to validate savings for a greater number of participants than previously identified.
- Regional-specific data allowed for greater refinement to the ex ante estimates for peaksaverPLUS for 2012. Experiments for testing new cycling strategies have been initiated in 2013 to further enhance these results.
- Improvements in the 2012 performance of DR-3 participants resulted in higher ex ante estimates for this initiative.
- The realization rates for 2012 demand savings in Small Business Lighting (SBL) are different compared to the assumptions used in the quarterly reports, which were based on 2011 results. There was a greater variance in operating profiles of the buildings participating in SBL in 2012. Energy results were less impacted.
- True-up analysis and reporting for 2011 is shown for the first time in this report and will continue each year until the end of the 2011 – 2014 reporting period. This true-up analysis ensures that energy and demand savings are properly categorized in the year that they were achieved and that any omissions and/or errors identified after the release of the 2011 Final Results Report are properly accounted for and reported to the LDCs. The true-up process was developed by the LDC Reporting Working Group. While the results will be identified as 2012, cumulative energy savings will commence from 2011.

Results are considered draft and may be subject to change. Results for the Home Assistance Program, New Home Construction, and High Performance New Construction, are currently unverified with verified results to be provided in the 2012 Final Results Report.

The OPA is committed to providing LDCs with the opportunity to review and provide feedback. To ensure that all inquiries can be directed to the appropriate OPA contact and addressed prior to the release of the final results, please e-mail a list of questions and/or concerns to LDC Support (LDC.Support@powerauthority.on.ca) by Monday, August 12, 2013.

The Final 2012 Results Report will be available to all LDCs on or before August 31, 2013. All results will be considered final for 2012. Any additional 2012 program activity not captured will be reported in the Final 2013 Results Report through the 2012 true-up process.

We appreciate your collaboration and cooperation throughout the reporting and evaluation process and we look forward to another successful year ahead.

Please continue to monitor saveONenergy E-blasts for any further updates and should you have any other questions or comments please contact LDC.Support@powerauthority.on.ca.

Sincerely,

Andrew Pride

Table of Contents

OPA-Contracted Province-Wide CDM Programs FINAL 2012 Results

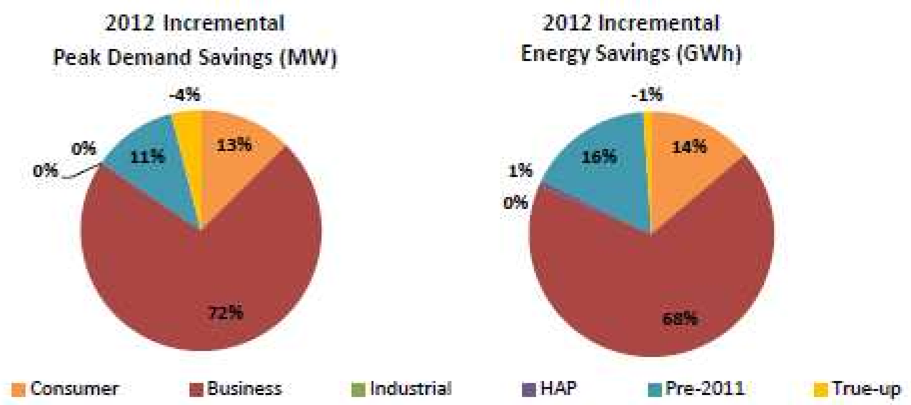
LDC: COLLUS Power Corporation

FINAL 2012 Progress to Targets	Annual	Scenario 1: % of Target Achieved	Scenario 2: % of Target Achieved
Net Annual Peak Demand Savings (MW)	0.3	13.8%	15.0%
Net Energy Savings (GWh)	1.2	45.5%	45.5%

Scenario 1 = Assumes that demand resource resources have a persistence of 1 year

Scenario 2 = Assumes that demand response resources remain in your territory until 2014

Achievement by Sector



Comparison: Your Achievement vs. LDC Community Achievement (Progress to Target)

The following graphs assume that demand response resources remain in your territory until 2014 (aligns with Scenario 2)

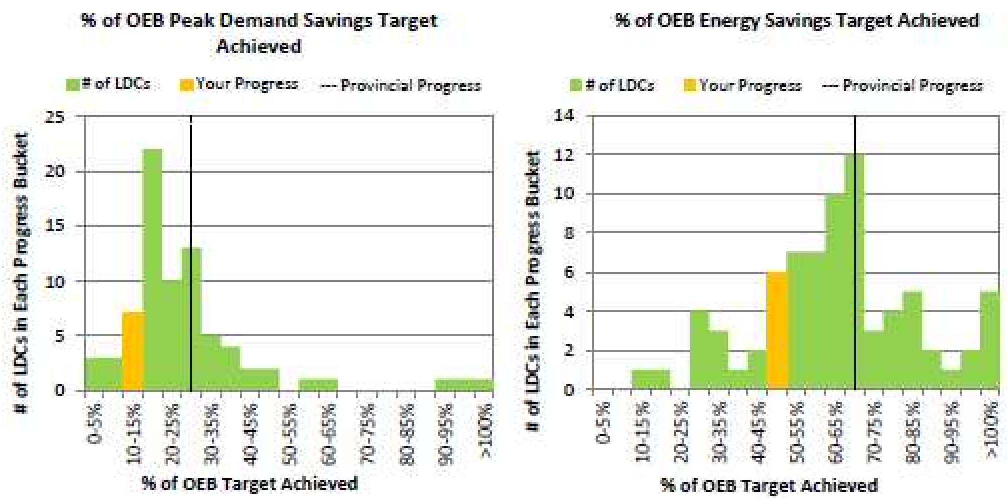


Table 1: COLLUS Power Corporation Initiative and Program Level Savings by Year (Scenario 1)

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR): 2014 Net Annual Peak Demand Savings (kW)	Program-to-Date Verified Progress to Target (excludes DR): 2011-2014 Net Cumulative Energy Savings (kWh)
		2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	128	97			8	5			52,747	38,949			12	327,532
Appliance Exchange	Appliances	11	2			1	0			1,671	542			1	7,863
HVAC Incentives	Equipment	147	155			46	33			87,511	53,517			79	510,594
Conservation Instant Coupon Booklet	Coupons	1,432	88			3	1			53,469	3,996			4	225,863
Bi-Annual Retailer Event	Coupons	2,487	3,032			5	4			83,982	76,536			9	565,535
Retailer Co-op	Items	0	0			0	0			0	0			0	0
Residential Demand Response (switch/pstat)*	Devices	0	0			0	0			0	0			0	0
Residential Demand Response (IHD)	Devices	0	0			0	0			0	0			0	0
Residential New Construction	Homes	0	0			0	0			0	0			0	0
Consumer Program Total						**63**	**43**			**279,380**	**173,539**			**105**	**1,637,387**
Business Program															
Retrofit	Projects	4	8			16	169			116,644	687,689			177	2,483,674
Direct Install Lighting	Projects	37	38			61	43			161,529	166,474			75	1,063,606
Building Commissioning	Buildings	0	0			0	0			0	0			0	0
New Construction	Buildings	0	0			0	0			0	0			0	0
Energy Audit	Audits	0	0			0	0			0	0			0	0
Small Commercial Demand Response (switch/pstat)*	Devices	0	0			0	0			0	0			0	0
Small Commercial Demand Response (IHD)	Devices	0	0			0	0			0	0			0	0
Demand Response 3*	Facilities	1	1			37	37			1,451	542			0	1,993
Business Program Total						**114**	**249**			**279,625**	**854,705**			**252**	**3,549,273**
Industrial Program															
Process & System Upgrades	Projects	0	0			0	0			0	0			0	0
Monitoring & Targeting	Projects	0	0			0	0			0	0			0	0
Energy Manager	Projects	0	0			0	0			0	0			0	0
Retrofit	Projects	1				3				20,487				3	81,948
Demand Response 3*	Facilities	0	0			0	0			0	0			0	0
Industrial Program Total						**3**	**0**			**20,487**	**0**			**3**	**81,948**
Home Assistance Program															
Home Assistance Program	Homes	0	19			0	1			0	8,922			1	26,765
Home Assistance Program Total						**0**	**1**			**0**	**8,922**			**1**	**26,765**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	2	0			3	0			15,807	0			3	63,228
High Performance New Construction	Projects	2	1			44	40			225,075	210,514			83	1,531,840
Toronto Comprehensive	Projects	0	0			0	0			0	0			0	0
Multifamily Energy Efficiency Rebates	Projects	0	0			0	0			0	0			0	0
LDC Custom Programs	Projects	0	0			0	0			0	0			0	0
Pre-2011 Programs completed in 2011 Total						**47**	**40**			**240,882**	**210,514**			**86**	**1,595,068**
Other															
Program Enabled Savings	Projects														
Time-of-Use Savings	Homes														
Other Total							**0**				**0**			**0**	**0**
Adjustments to Previous Year's Verified Results							**-14**				**-19,595**			**-14**	**-78,380**
Energy Efficiency Total						**188**	**295**			**818,923**	**1,247,158**			**447**	**6,888,448**
Demand Response Total (Scenario 1)						**37**	**37**			**1,451**	**542**			**0**	**1,993**
OPA-Contracted LDC Portfolio Total						**226**	**319**			**820,374**	**1,228,085**			**433**	**6,812,061**
													Full OEB Target:	**3,140**	**14,970,000**
													% of Full OEB Target Achieved to Date (Scenario 1):	**13.8%**	**45.5%**

* Activity & savings for Demand Response resources for each year and quarter represent the savings from all active facilities or devices contracted since January 1, 2011.

* Verified activity & savings data is not available at this time. Unverified 2012 results are used in this draft report but will be replaced with verified data in the final report.

Table 2: Adjustments to COLLUS Power Corporation Verified Results due to Errors or Omissions (Scenario 1)

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR) 2014 Net Annual Peak Demand Savings (kW)	Program-to-Date Verified Progress to Target (excludes DR) 2011-2014 Net Cumulative Energy Savings (kWh)
		2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	0				0				0				0	0
Appliance Exchange	Appliances	0				0				0				0	0
HVAC Incentives	Equipment	-48				-14				-26,622				-14	-106,489
Conservation Instant Coupon Booklet	Coupons	23				0				788				0	3,151
Bi-Annual Retailer Event	Coupons	234				0				6,240				0	24,958
Retailer Co-op	Items	0				0				0				0	0
Residential Demand Response (switch/pstat)*	Devices	0				0				0				0	0
Residential Demand Response (IHD)	Devices	0				0				0				0	0
Residential New Construction	Homes	0				0				0				0	0
Consumer Program Total						-14				-19,595				-14	-78,380
Business Program															
Retrofit	Projects	0				0				0				0	0
Direct Install Lighting	Projects	0				0				0				0	0
Building Commissioning	Buildings	0				0				0				0	0
New Construction	Buildings	0				0				0				0	0
Energy Audit	Audits	0				0				0				0	0
Small Commercial Demand Response (switch/pstat)*	Devices	0				0				0				0	0
Small Commercial Demand Response (IHD)	Devices	0				0				0				0	0
Demand Response 3*	Facilities	0				0				0				0	0
Business Program Total						0				0				0	0
Industrial Program															
Process & System Upgrades	Projects	0				0				0				0	0
Monitoring & Targeting	Projects	0				0				0				0	0
Energy Manager	Projects	0				0				0				0	0
Retrofit	Projects	0				0				0				0	0
Demand Response 3*	Facilities	0				0				0				0	0
Industrial Program Total						0				0				0	0
Home Assistance Program															
Home Assistance Program	Homes	0				0				0				0	0
Home Assistance Program Total						0				0				0	0
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	0				0				0				0	0
High Performance New Construction	Projects	0				0				0				0	0
Toronto Comprehensive	Projects	0				0				0				0	0
Multifamily Energy Efficiency Rebates	Projects	0				0				0				0	0
LDC Custom Programs	Projects	0				0				0				0	0
Pre-2011 Programs completed in 2011 Total						0				0				0	0
Other															
Program Enabled Savings	Projects														
Time-of-Use Savings	Homes														
Other Total						0				0				0	0
Adjustments to Previous Year's Verified Results						-14				-19,595				-14	-78,380

* Activity & savings for Demand Response resources for each year and quarter represent the savings from all active facilities or devices contracted since January 1, 2011.

Table 3: COLLUS Power Corporation Realization Rate & NTG

Initiative	Peak Demand Savings								Energy Savings							
	Realization Rate				Net-to-Gross Ratio				Realization Rate				Net-to-Gross Ratio			
	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program																
Appliance Retirement		1.00				0.47				1.00				0.47		
Appliance Exchange		1.00				0.52				1.00				0.52		
HVAC Incentives		1.00				0.51				1.00				0.50		
Conservation Instant Coupon Booklet		1.00				1.00				1.00				1.05		
Bi-Annual Retailer Event		1.00				0.91				1.00				0.92		
Retailer Co-op		n/a				n/a				n/a				n/a		
Residential Demand Response (switch/pstat)*		n/a				n/a				n/a				n/a		
Residential Demand Response (IHD)		n/a				n/a				n/a				n/a		
Residential New Construction		n/a				n/a				n/a				n/a		
Business Program																
Retrofit		0.93				0.77				1.13				0.79		
Direct Install Lighting		0.68				0.94				0.85				0.94		
Building Commissioning		n/a				n/a				n/a				n/a		
New Construction		n/a				n/a				n/a				n/a		
Energy Audit		n/a				n/a				n/a				n/a		
Small Commercial Demand Response (switch/pstat)*		n/a				n/a				n/a				n/a		
Small Commercial Demand Response (IHD)		n/a				n/a				n/a				n/a		
Demand Response 3*		n/a				n/a				n/a				n/a		
Industrial Program																
Process & System Upgrades		n/a				n/a				n/a				n/a		
Monitoring & Targeting		n/a				n/a				n/a				n/a		
Energy Manager		n/a				n/a				n/a				n/a		
Retrofit																
Demand Response 3*		n/a				n/a				n/a				n/a		
Home Assistance Program																
Home Assistance Program		n/a				n/a				n/a				n/a		
Pre-2011 Programs completed in 2011																
Electricity Retrofit Incentive Program		n/a				n/a				n/a				n/a		
High Performance New Construction		n/a				n/a				n/a				n/a		
Toronto Comprehensive		n/a				n/a				n/a				n/a		
Multifamily Energy Efficiency Rebates		n/a				n/a				n/a				n/a		
LDC Custom Programs		n/a				n/a				n/a				n/a		
Other																
Program Enabled Savings		n/a				n/a				n/a				n/a		
Time-of-Use Savings		n/a				n/a				n/a				n/a		

Progress Towards CDM Targets

Results are attributed to target using current OPA reporting policies. Energy efficiency resources persist for the duration of the effective useful life. Any upcoming code changes are taken into account. Demand response resources persist for 1 year. Please see methodology tab for more detailed information.

Table 4: Net Peak Demand Savings at the End User Level (MW)

Implementation Period	Annual			
	2011	2012	2013	2014
2011 - Verified	0.2	0.2	0.2	0.2
2012 - Verified		0.3	0.3	0.3
2013				
2014				
Verified Net Annual Peak Demand Savings Persisting in 2014:				0.4
COLLUS Power Corporation 2014 Annual CDM Capacity Target				3.1
Verified Portion of Peak Demand Savings Target Achieved in 2014(%):				13.8%

Table 5: Net Energy Savings at the End User Level (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011 - Verified	0.8	0.8	0.8	0.7	3.2
2012 - Verified		1.2	1.2	1.2	3.6
2013					
2014					
Verified Net Cumulative Energy Savings 2011-2014:					6.8
COLLUS Power Corporation 2011-2014 Annual CDM Energy Target					15.0
Verified Portion of Cumulative Energy Target Achieved (%):					45.5%

Table 6: Province-Wide Initiatives and Program Level Savings by Year

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR): 2014 Net Annual Peak Demand Savings (kW)	Program-to-Date Verified Progress to Target (excludes DR): 2011-2014 Net Cumulative Energy Savings (kWh)
		2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	56,110	34,146			3,299	2,011			23,005,812	13,424,518			5,171	132,176,857
Appliance Exchange	Appliances	3,688	3,836			371	556			450,187	974,621			689	4,512,525
HVAC Incentives	Equipment	111,587	85,221			32,037	19,060			59,437,670	32,841,283			51,097	336,274,530
Conservation Instant Coupon Booklet	Coupons	559,462	30,891			1,344	230			21,211,537	1,398,202			1,575	89,040,754
Bi-Annual Retailer Event	Coupons	870,332	1,060,901			1,681	1,480			29,387,468	26,781,674			3,161	197,894,897
Retailer Co-op	Items	152	0			0	0			2,652	0			0	10,607
Residential Demand Response (switch/pstat)*	Devices	19,550	90,777			10,947	45,073			24,870	330,535			0	355,406
Residential Demand Response (IHD)	Devices	0	68,282			0	0			0	0			0	0
Residential New Construction	Homes	7	26			0	0			743	2,703			0	11,081
Consumer Program Total						**49,681**	**68,411**			**133,520,941**	**75,753,536**			**61,695**	**760,276,657**
Business Program															
Retrofit	Projects	2,516	5,580			24,467	60,885			136,002,258	310,521,399			83,766	1,467,444,252
Direct Install Lighting	Projects	20,297	18,490			23,724	15,279			61,076,701	57,327,805			31,175	391,018,889
Building Commissioning	Buildings	0	0			0	0			0	0			0	0
New Construction	Buildings	10	33			123	354			411,717	1,016,158			477	4,705,368
Energy Audit	Audits	103	280			0	1,450			0	7,049,351			1,450	21,148,054
Small Commercial Demand Response (switch/pstat)*	Devices	132	222			84	142			157	807			0	964
Small Commercial Demand Response (IHD)	Devices	0	0			0	0			0	0			0	0
Demand Response 3*	Facilities	145	151			16,224	19,389			633,421	281,823			0	915,244
Business Program Total						**64,623**	**97,508**			**198,124,253**	**376,199,351**			**116,868**	**1,885,228,768**
Industrial Program															
Process & System Upgrades	Projects	0	0			0	0			0	0			0	0
Monitoring & Targeting	Projects	0	0			0	0			0	0			0	0
Energy Manager	Projects	0	33			0	926			0	7,089,508			926	21,268,524
Retrofit	Projects	433				4,615				28,866,840				4,613	115,462,282
Demand Response 3*	Facilities	124	185			52,484	92,721			3,080,737	2,234,529			0	5,315,267
Industrial Program Total						**57,098**	**93,646**			**31,947,577**	**9,324,037**			**5,539**	**142,046,072**
Home Assistance Program															
Home Assistance Program	Homes	46	5,029			2	1,104			39,283	3,483,229			1,106	10,606,820
Home Assistance Program Total						**2**	**1,104**			**39,283**	**3,483,229**			**1,106**	**10,606,820**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	2,016	0			21,662	0			121,138,219	0			21,662	484,552,876
High Performance New Construction	Projects	145	203			5,098	7,854			26,185,591	41,753,108			12,953	230,001,690
Toronto Comprehensive	Projects	577	0			15,805	0			86,964,886	0			15,805	347,859,545
Multifamily Energy Efficiency Rebates	Projects	110	0			1,981	0			7,595,683	0			1,981	30,382,733
LDC Custom Programs	Projects	8	0			399	0			1,367,170	0			399	5,468,679
Pre-2011 Programs completed in 2011 Total						**44,945**	**7,854**			**243,251,550**	**41,753,108**			**52,799**	**1,098,265,523**
Other															
Program Enabled Savings	Projects														
Time-of-Use Savings	Homes														
Other Total							**0**				**0**			**0**	**0**
Adjustments to Previous Year's Verified Results							**-938**				**12,726,877**			**-1,189**	**50,064,110**
Energy Efficiency Total						**136,610**	**111,199**			**603,144,419**	**503,665,566**			**238,007**	**3,889,836,959**
Demand Response Total (Scenario 1)						**79,730**	**157,324**			**3,730,185**	**2,847,695**			**0**	**6,586,880**
OPA-Contracted LDC Portfolio Total						**216,340**	**267,585**			**606,883,604**	**519,239,938**			**236,818**	**3,946,487,955**
													Full OEB Target:	**1,330,000**	**6,000,000,000**
													% of Full OEB Target Achieved to Date (Scenario 1):	**17.8%**	**65.8%**

* Activity & savings for Demand Response resources for each year and quarter represent the savings from all active facilities or devices contracted since January 1, 2011.

* Verified activity & savings data is not available at this time. Unverified 2012 results are used in this draft report but will be replaced with verified data in the final report.

Table 7: Adjustments to Province-Wide Verified Results due to Errors & Omissions (Scenario 1)

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR)	
		2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014 Net Annual Peak Demand Savings (kW) 2014	2011-2014 Net Cumulative Energy Savings (kWh) 2014
Consumer Program															
Appliance Retirement	Appliances	0				0				0				0	0
Appliance Exchange	Appliances	0				0				0				0	0
HVAC Incentives	Equipment	-16,875				-5,281				-9,726,798				-5,281	-38,907,190
Conservation Instant Coupon Booklet	Coupons	8,216				16				275,655				16	1,102,621
Bi-Annual Retailer Event	Coupons	81,817				108				2,183,391				108	8,733,563
Retailer Co-op	Items	0				0				0				0	0
Residential Demand Response (switch/pstat)*	Devices	0				0				0				0	0
Residential Demand Response (IHD)	Devices	0				0				0				0	0
Residential New Construction	Homes	0				0				0				0	0
Consumer Program Total						-5,157				-7,267,752				-5,157	-29,071,007
Business Program															
Retrofit	Projects	303				3,204				16,216,165				3,083	64,398,674
Direct Install Lighting	Projects	444				501				1,250,388				372	4,624,945
Building Commissioning	Buildings	0				0				0				0	0
New Construction	Buildings	0				0				0				0	0
Energy Audit	Audits	93				481				2,341,392				481	9,365,567
Small Commercial Demand Response (switch/pstat)*	Devices	0				0				0				0	0
Small Commercial Demand Response (IHD)	Devices	0				0				0				0	0
Demand Response 3*	Facilities	0				0				0				0	0
Business Program Total						4,186				19,807,944				3,936	78,389,186
Industrial Program															
Process & System Upgrades	Projects	0				0				0				0	0
Monitoring & Targeting	Projects	0				0				0				0	0
Energy Manager	Projects	0				0				0				0	0
Retrofit	Projects	0				0				0				0	0
Demand Response 3*	Facilities	0				0				0				0	0
Industrial Program Total						0				0				0	0
Home Assistance Program															
Home Assistance Program	Homes	0				0				0				0	0
Home Assistance Program Total						0				0				0	0
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	7				32				186,484				32	745,937
High Performance New Construction	Projects	0				0				0				0	0
Toronto Comprehensive	Projects	0				0				0				0	0
Multifamily Energy Efficiency Rebates	Projects	0				0				0				0	0
LDC Custom Programs	Projects	0				0				0				0	0
Pre-2011 Programs completed in 2011 Total						32				186,484				32	745,937
Other															
Program Enabled Savings	Projects														
Time-of-Use Savings	Homes														
Other Total						0				0				0	0
Adjustments to Previous Year's Verified Results						-938				12,726,677				-1,189	50,064,116

* Activity & savings for Demand Response resources for each year and quarter represent the savings from all active facilities or devices contracted since January 1, 2011.

Table 8: Province-Wide Realization Rate & NTG

Initiative	Peak Demand Savings								Energy Savings							
	Realization Rate				Net-to-Gross Ratio				Realization Rate				Net-to-Gross Ratio			
	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program																
Appliance Retirement		1.00				0.46				1.00				0.47		
Appliance Exchange		1.00				0.52				1.00				0.52		
HVAC Incentives		1.00				0.50				1.00				0.49		
Conservation Instant Coupon Booklet		1.00				1.00				1.00				1.05		
Bi-Annual Retailer Event		1.00				0.91				1.00				0.92		
Retailer Co-op		n/a				n/a				n/a				n/a		
Residential Demand Response (switch/pstat)*		n/a				n/a				n/a				n/a		
Residential Demand Response (IHD)		n/a				n/a				n/a				n/a		
Residential New Construction		n/a				n/a				n/a				n/a		
Business Program																
Retrofit		0.93				0.75				1.05				0.76		
Direct Install Lighting		0.69				0.94				0.85				0.94		
Building Commissioning		n/a				n/a				n/a				n/a		
New Construction		n/a				n/a				n/a				n/a		
Energy Audit		n/a				n/a				n/a				n/a		
Small Commercial Demand Response (switch/pstat)*		n/a				n/a				n/a				n/a		
Small Commercial Demand Response (IHD)		n/a				n/a				n/a				n/a		
Demand Response 3*		n/a				n/a				n/a				n/a		
Industrial Program																
Process & System Upgrades		n/a				n/a				n/a				n/a		
Monitoring & Targeting		n/a				n/a				n/a				n/a		
Energy Manager		1.15				0.90				1.15				0.91		
Retrofit																
Demand Response 3*		n/a				n/a				n/a				n/a		
Home Assistance Program																
Home Assistance Program		n/a				n/a				n/a				n/a		
Pre-2011 Programs completed in 2011																
Electricity Retrofit Incentive Program		n/a				n/a				n/a				n/a		
High Performance New Construction		n/a				n/a				n/a				n/a		
Toronto Comprehensive		n/a				n/a				n/a				n/a		
Multifamily Energy Efficiency Rebates		n/a				n/a				n/a				n/a		
LDC Custom Programs		n/a				n/a				n/a				n/a		
Other																
Program Enabled Savings		n/a				n/a				n/a				n/a		
Time-of-Use Savings		n/a				n/a				n/a				n/a		

Summary - Provincial Progress

Table 9: Province-Wide Net Peak Demand Savings at the End User Level (MW)

Implementation Period	Annual			
	2011	2012	2013	2014
2011	216.3	136.6	135.8	129.0
2012		266.6	109.4	107.8
2013				
2014				
Verified Net Annual Peak Demand Savings in 2014:				236.8
2014 Annual CDM Capacity Target				1,330
Verified Peak Demand Savings Target Achieved - 2011 (%):				17.8%

Table 10: Province-Wide Net Energy Savings at the End-User Level (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011	606.9	603.0	601.0	582.3	2,393
2012		532.0	513.6	507.8	1,553
2013					
2014					
Verified Net Cumulative Energy Savings 2011-2014:					3,946
2011-2014 Cumulative CDM Energy Target:					6,000
Verified Portion of Energy Target Achieved - 2011 (%):					65.8%

METHODOLOGY

All results are at the end-user level (not including transmission and distribution losses)

EQUATIONS	
Prescriptive Measures and Projects	**Gross Savings** = Activity * Per Unit Assumption **Net Savings** = Gross Savings * Net-to-Gross Ratio All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)
Engineered and Custom Projects	**Gross Savings** = Reported Savings * Realization Rate **Net Savings** = Gross Savings * Net-to-Gross Ratio All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)
Demand Response	**Peak Demand: Gross Savings = Net Savings** = contracted MW at contributor level * Provincial contracted to ex ante ratio **Energy: Gross Savings = Net Savings** = provincial ex post energy savings * LDC proportion of total provincial contracted MW All savings are annualized (i.e. the savings are the same regardless of the time of year a participant began offering DR)
Adjustments to Previous Year's Verified Results	All errors and omissions from the prior years Final Annual Results report will be adjusted within this report. Any errors and ommissions with regards to projects counts, data lag, and calculations etc., will be made within this report. Considers the cumulative effect of energy savings.

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Consumer Program			
Appliance Retirement	Includes both retail and home pickup stream; Retail stream allocated based on average of 2008 & 2009 residential throughput; Home pickup stream directly attributed by postal code or customer selection	Savings are considered to begin in the year the appliance is picked up.	Peak demand and energy savings are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Appliance Exchange	When postal code information is provided by customer, results are directly attributed to the LDC. When postal code is not available, results allocated based on average of 2008 & 2009 residential throughput	Savings are considered to begin in the year that the exchange event occurred	
HVAC Incentives	Results directly attributed to LDC based on customer postal code	Savings are considered to begin in the year that the installation occurred	

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Conservation Instant Coupon Booklet	LDC-coded coupons directly attributed to LDC; Otherwise results are allocated based on average of 2008 & 2009 residential throughput	Savings are considered to begin in the year in which the coupon was redeemed.	Peak demand and energy savings are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Bi-Annual Retailer Event	Results are allocated based on average of 2008 & 2009 residential throughput	Savings are considered to begin in the year in which the event occurs.	
Retailer Co-op	When postal code information is provided by the customer, results are directly attributed. If postal code information is not available, results are allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year of the home visit and installation date.	Peak demand and energy savings are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Residential Demand Response	Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists	Savings are considered to begin in the year the device was installed and/or when a customer signed a *peaksaver* PLUS™ participant agreement.	Peak demand savings are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. Energy savings are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year and accounts for any "snapback" in energy consumption experienced after the event. Savings are assumed to persist for only 1 year, reflecting that savings will only occur if the resource is activated.

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Commercial Demand Response (part of the Residential program schedule)	Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists	Savings are considered to begin in the year the device was installed and/or when a customer signed a *peaksaver* PLUS™ participant agreement.	**Peak demand savings** are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. **Energy savings** are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year. Savings are assumed to persist for only 1 year, reflecting that savings will only occur if the resource is activated.
Demand Response 3 (part of the Industrial program schedule)	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year in which the contributor signed up to participate in demand response.	**Peak demand savings** are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. **Energy savings** are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.
Industrial Program			
Process & System Upgrades	Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system; Initiative was not evaluated, no completed projects in 2011 or 2012.	Savings are considered to begin in the year in which the incentive project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping	Savings are considered to begin in the year of the actual project completion date on the iCON CRM system.	**Peak demand and energy savings** are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
Demand Response 3	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year in which the contributor signed up to participate in demand response.	**Peak demand savings** are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. **Energy savings** are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.
Home Assistance Program			

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Home Assistance Program	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the measures were installed.	Peak demand and energy savings are determined using the measure level per unit assumption multiplied by the uptake of each measure (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Pre-2011 Programs completed in 2011			
Electricity Retrofit Incentive Program	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011 or 2012, assumptions as per 2010 evaluation	Savings are considered to begin in the year in which a project was completed.	Peak demand and energy savings are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). If energy savings are not available, an estimate is made based on the kWh to kW ratio in the provincial results from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
High Performance New Construction	Results are directly attributed to LDC based on customer data provided to the OPA from Enbridge; Initiative was not evaluated in 2011 or 2012, assumptions as per 2010 evaluation	Savings are considered to begin in the year in which a project was completed.	
Toronto Comprehensive	Program run exclusively in Toronto Hydro-Electric System Limited service territory; Initiative was not evaluated in 2011 or 2012, assumptions as per 2010 evaluation		

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Multifamily Energy Efficiency Rebates	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011 or 2012, assumptions as per 2010 evaluation	Savings are considered to begin in the year in which a project was completed.	**Peak demand and energy savings are** determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). **If energy savings are not available,** an estimate is made based on the kWh to kW ratio in the provincial results from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
Data Centre Incentive Program	Program run exclusively in PowerStream Inc. service territory; Initiative was not evaluated in 2011, assumptions as per 2009 evaluation		
EnWin Green Suites	Program run exclusively in ENWIN Utilities Ltd. service territory; Initiative was not evaluated in 2011 or 2012, assumptions as per 2010 evaluation		

ERII Sector (C&I vs. Industrial Mapping)

Building Type	Sector
Agribusiness - Cattle Farm	C&I
Agribusiness - Dairy Farm	C&I
Agribusiness - Greenhouse	C&I
Agribusiness - Other	C&I
Agribusiness - Other,Mixed-Use - Office/Retail	C&I
Agribusiness - Other,Office,Retail,Warehouse	C&I
Agribusiness - Other,Office,Warehouse	C&I
Agribusiness - Poultry	C&I
Agribusiness - Poultry,Hospitality - Motel	C&I
Agribusiness - Swine	C&I
Convenience Store	C&I
Education - College / Trade School	C&I
Education - College / Trade School,Multi-Residential - Condominium	C&I
Education - College / Trade School,Multi-Residential - Rental Apartment	C&I
Education - College / Trade School,Retail	C&I
Education - Primary School	C&I
Education - Primary School,Education - Secondary School	C&I
Education - Primary School,Multi-Residential - Rental Apartment	C&I
Education - Primary School,Not-for-Profit	C&I
Education - Secondary School	C&I
Education - University	C&I
Education - University,Office	C&I
Hospital/Healthcare - Clinic	C&I
Hospital/Healthcare - Clinic,Hospital/Healthcare - Long-term Care,Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Clinic,Industrial	C&I
Hospital/Healthcare - Clinic,Retail	C&I
Hospital/Healthcare - Long-term Care	C&I
Hospital/Healthcare - Long-term Care,Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Medical Building,Mixed-Use - Office/Retail	C&I
Hospital/Healthcare - Medical Building,Mixed-Use - Office/Retail,Office	C&I
Hospitality - Hotel	C&I
Hospitality - Hotel,Restaurant - Dining	C&I
Hospitality - Motel	C&I
Industrial	Industrial
Mixed-Use - Office/Retail	C&I
Mixed-Use - Office/Retail,Industrial	Industrial
Mixed-Use - Office/Retail,Mixed-Use - Other	C&I
Mixed-Use - Office/Retail,Mixed-Use - Other,Not-for-Profit,Warehouse	C&I
Mixed-Use - Office/Retail,Mixed-Use - Residential/Retail	C&I
Mixed-Use - Office/Retail,Office,Restaurant - Dining,Restaurant - Quick Serve,Retail,Warehouse	C&I

Mixed-Use - Office/Retail,Office,Warehouse	C&I
Mixed-Use - Office/Retail,Retail	C&I
Mixed-Use - Office/Retail,Warehouse	C&I
Mixed-Use - Office/Retail,Warehouse,Industrial	Industrial
Mixed-Use - Other	C&I
Mixed-Use - Other,Industrial	Industrial
Mixed-Use - Other,Not-for-Profit,Office	C&I
Mixed-Use - Other,Office	C&I
Mixed-Use - Other,Other: Please specify	C&I
Mixed-Use - Other,Retail,Warehouse	C&I
Mixed-Use - Other,Warehouse	C&I
Mixed-Use - Residential/Retail	C&I
Mixed-Use - Residential/Retail,Multi-Residential - Condominium	C&I
Mixed-Use - Residential/Retail,Multi-Residential - Rental Apartment	C&I
Mixed-Use - Residential/Retail,Retail	C&I
Multi-Residential - Condominium	C&I
Multi-Residential - Condominium,Multi-Residential - Rental Apartment	C&I
Multi-Residential - Condominium,Other: Please specify	C&I
Multi-Residential - Rental Apartment	C&I
Multi-Residential - Rental Apartment,Multi-Residential - Social Housing Provider,Not-for-Profit	C&I
Multi-Residential - Rental Apartment,Not-for-Profit	C&I
Multi-Residential - Rental Apartment,Warehouse	C&I
Multi-Residential - Social Housing Provider	C&I
Multi-Residential - Social Housing Provider,Industrial	C&I
Multi-Residential - Social Housing Provider,Not-for-Profit	C&I
Not-for-Profit	C&I
Not-for-Profit,Office	C&I
Not-for-Profit,Other: Please specify	C&I
Not-for-Profit,Warehouse	C&I
Office	C&I
Office,Industrial	Industrial
Office,Other: Please specify	C&I
Office,Other: Please specify,Warehouse	C&I
Office,Restaurant - Dining	C&I
Office,Restaurant - Dining,Industrial	Industrial
Office,Retail	C&I
Office,Retail,Industrial	C&I
Office,Retail,Warehouse	C&I
Office,Warehouse	C&I
Office,Warehouse,Industrial	Industrial
Other: Please specify	C&I
Other: Please specify,Industrial	Industrial
Other: Please specify,Retail	C&I
Other: Please specify,Warehouse	C&I
Restaurant - Dining	C&I
Restaurant - Dining,Retail	C&I

Restaurant - Quick Serve	C&I
Restaurant - Quick Serve,Retail	C&I
Retail	C&I
Retail,Industrial	Industrial
Retail,Warehouse	C&I
Warehouse	C&I
Warehouse,Industrial	Industrial

Consumer Program Allocation Methodology

Results can be allocated based on average of 2008 & 2009 residential throughput for each LDC (below) when additional information is not available. Source: OEB Yearbook Data 2008 & 2009

Local Distribution Company	Allocation
Algoma Power Inc.	0.2%
Atikokan Hydro Inc.	0.0%
Attawapiskat Power Corporation	0.0%
Bluewater Power Distribution Corporation	0.6%
Brant County Power Inc.	0.2%
Brantford Power Inc.	0.7%
Burlington Hydro Inc.	1.4%
Cambridge and North Dumfries Hydro Inc.	1.0%
Canadian Niagara Power Inc.	0.5%
Centre Wellington Hydro Ltd.	0.1%
Chapleau Public Utilities Corporation	0.0%
COLLUS Power Corporation	0.3%
Cooperative Hydro Embrun Inc.	0.0%
E.L.K. Energy Inc.	0.2%
Enersource Hydro Mississauga Inc.	3.9%
ENTEGRUS	0.6%
ENWIN Utilities Ltd.	1.6%
Erie Thames Powerlines Corporation	0.4%
Espanola Regional Hydro Distribution Corporation	0.1%
Essex Powerlines Corporation	0.7%
Festival Hydro Inc.	0.3%
Fort Albany Power Corporation	0.0%
Fort Frances Power Corporation	0.1%
Greater Sudbury Hydro Inc.	1.0%
Grimsby Power Inc.	0.2%
Guelph Hydro Electric Systems Inc.	0.9%
Haldimand County Hydro Inc.	0.4%
Halton Hills Hydro Inc.	0.5%
Hearst Power Distribution Company Limited	0.1%
Horizon Utilities Corporation	4.0%
Hydro 2000 Inc.	0.0%
Hydro Hawkesbury Inc.	0.1%
Hydro One Brampton Networks Inc.	2.8%
Hydro One Networks Inc.	30.0%

Hydro Ottawa Limited	5.6%
Innisfil Hydro Distribution Systems Limited	0.4%
Kashechewan Power Corporation	0.0%
Kenora Hydro Electric Corporation Ltd.	0.1%
Kingston Hydro Corporation	0.5%
Kitchener-Wilmot Hydro Inc.	1.6%
Lakefront Utilities Inc.	0.2%
Lakeland Power Distribution Ltd.	0.2%
London Hydro Inc.	2.7%
Middlesex Power Distribution Corporation	0.1%
Midland Power Utility Corporation	0.1%
Milton Hydro Distribution Inc.	0.6%
Newmarket - Tay Power Distribution Ltd.	0.7%
Niagara Peninsula Energy Inc.	1.0%
Niagara-on-the-Lake Hydro Inc.	0.2%
Norfolk Power Distribution Inc.	0.3%
North Bay Hydro Distribution Limited	0.5%
Northern Ontario Wires Inc.	0.1%
Oakville Hydro Electricity Distribution Inc.	1.5%
Orangeville Hydro Limited	0.2%
Orillia Power Distribution Corporation	0.3%
Oshawa PUC Networks Inc.	1.2%
Ottawa River Power Corporation	0.2%
Parry Sound Power Corporation	0.1%
Peterborough Distribution Incorporated	0.7%
PowerStream Inc.	6.6%
PUC Distribution Inc.	0.9%
Renfrew Hydro Inc.	0.1%
Rideau St. Lawrence Distribution Inc.	0.1%
Sioux Lookout Hydro Inc.	0.1%
St. Thomas Energy Inc.	0.3%
Thunder Bay Hydro Electricity Distribution Inc.	0.9%
Tillsonburg Hydro Inc.	0.1%
Toronto Hydro-Electric System Limited	12.8%
Veridian Connections Inc.	2.4%
Wasaga Distribution Inc.	0.2%
Waterloo North Hydro Inc.	1.0%
Welland Hydro-Electric System Corp.	0.4%
Wellington North Power Inc.	0.1%
West Coast Huron Energy Inc.	0.1%
Westario Power Inc.	0.5%
Whitby Hydro Electric Corporation	0.9%
Woodstock Hydro Services Inc.	0.3%

b)

Load Forecast CDM Adjustment Work Form (2013)

Collus PowerStream Power Corp. *EB-2012-0116*

4 Year (2011-2014) kWh Target:					
14,970,000					
	2011	2012	2013	2014	Total
%					
2011 CDM Programs	5.48%	5.48%	5.48%	4.94%	21.38%
2012 CDM Programs		13.10%	13.10%	13.10%	39.31%
2013 CDM Programs			13.10%	13.10%	26.21%
2014 CDM Programs				13.10%	13.10%
Total in Year	**5.48%**	**18.58%**	**31.69%**	**44.26%**	**100.00%**
kWh					
2011 CDM Programs	820,000	820,000	820,000	740,000	3,200,000
2012 CDM Programs		1,961,667	1,961,667	1,961,667	5,885,000
2013 CDM Programs			1,961,667	1,961,667	3,923,333
2014 CDM Programs				1,961,667	1,961,667
Total in Year	**820,000**	**2,781,667**	**4,743,333**	**6,625,000**	**14,970,000**
				Check	14,970,000

Net-to-Gross Conversion	"Gross"	"Net"	Difference	"Net-to-Gross" Conversion Factor ('g')
2006 to 2011 OPA CDM programs: Persistence to 2013	58,983,238	38,275,632	20,707,606	54.10%

	2011	2012	2013	2014	Total for 2013
Amount used for CDM threshold for LRAMVA	820,000	1,961,667	1,961,667		4,743,333
Manual Adjustment for 2013 Load Forecast	631,815	3,022,953	1,511,477		5,166,245
Manual adjustment uses "gross" versus "net" (i.e. numbers multiplied by (1 + g)	*50% assumed to be in base forecast, so 50% needed for full year persistence by 2014*		*Only 50% of 2013 CDM impact is used based on a half year rule*		

c)

2006-2010 Net CDM kWh Savings

	2006	2007	2008	2009	2010	2011	2012	2013	
Residential	1,031,866	1,031,866	1,031,866	1,031,866	179,212	179,212	163,930	163,930	
		1,002,272	596,542	545,982	545,982	545,982	530,925	530,925	
			626,479	544,982	544,982	544,982	494,419	494,313	
				320,875	314,870	314,870	314,566	289,239	
					213,350	206,227	204,581	204,443	
	1,031,866	2,034,138	2,254,887	2,443,705	1,798,396	1,791,273	1,708,421	1,682,850	
C&I GS<50	-	-	-	-	-	-	-	-	
		-	-	-	-	-	-	-	
			-	-	-	-	-	-	
				542,273	542,273	542,273	542,273	542,273	
					49,764	49,764	49,764	49,764	
	-	-	-	542,273	592,037	592,037	592,037	592,037	
C&I GS>50	-	-	-	-	-	-	-	-	
		546,624	546,624	546,624	546,624	546,624	546,624	546,624	
			776,424	776,419	776,419	776,419	776,419	776,419	
				1,312,521	1,110,316	1,110,316	1,110,316	1,110,316	
					1,275,696	881,395	881,395	881,395	
	-	546,624	1,323,048	2,635,564	3,709,055	3,314,754	3,314,754	3,314,754	
	1,031,866	2,580,762	3,577,935	5,621,542	6,099,488	5,698,064	5,615,212	5,589,641	35,814,510

2011-2014 Net CDM kW Savings

	2011	2012	2013	
Residential	279,380	279,380	279,380	
GS<50	195,812	195,812	195,812	
GS>50	345,181	345,181	345,181	
	820,373	820,373	820,373	2,461,119
				38,275,629

2006-2010 Net CDM kW Savings

	2006	2007	2008	2009	2010	2011	2012	2013	
Residential	0.86	0.05	0.05	0.05	0.05	0.05	0.05	0.05	
		0.36	0.17	0.12	0.12	0.12	0.12	0.12	
			0.10	0.09	0.09	0.09	0.09	0.09	
				0.08	0.08	0.08	0.08	0.08	
					0.05	0.05	0.05	0.05	
	0.86	0.41	0.32	0.35	0.39	0.39	0.39	0.39	
C&I GS<50	-	-	-	-	-	-	-	-	
		-	-	-	-	-	-	-	
			-	-	-	-	-	-	
				0.08	0.08	0.08	0.08	0.08	
					0.01	0.01	0.01	0.01	
	-	-	-	0.08	0.09	0.09	0.09	0.09	
C&I GS>50	-	-	-	-	-	-	-	-	
		1.02	0.12	0.12	0.12	0.12	0.12	0.12	
			1.56	0.15	0.15	0.15	0.15	0.15	
				1.50	0.29	0.29	0.29	0.29	
					1.39	0.29	0.29	0.29	
	-	1.02	1.68	1.77	1.95	0.86	0.86	0.86	
	0.86	1.42	2.00	2.20	2.43	1.34	1.34	1.33	12.91

2011-2014 Net CDM kW Savings

	2011	2012	2013	
Residential	63	63	63	
GS<50	103	103	103	
GS>50	60	60	60	
	226	226	226	678
				691

d) Collus PowerStream utilized the following approach to derive its load forecast by class:

1. Historic total electricity volume reductions resulting from CDM initiatives were grossed up for losses to derive gross CDM volume reductions;
2. Add these gross CDM volume reductions to the historic wholesale values, to derive load values as if CDM initiatives never took place;
3. Develop forecast values using grossed-up values derived in Step 2;
4. Subtract grossed up CDM volume reductions from the gross purchase forecast, to derive load values when CDM is taking place;
5. Remove losses to derive sales volumes;
6. Allocate sales volumes to rate classes based on the historic ratios.

Collus PowerStream believes that this approach is consistent with the methodology that is described in Board Staff IR 18(d).

e) Collus PowerStream's does not feel that allocating savings equally over the years 2011 through 2014, as the model provided by the Board does, accurately reflects the actual savings being achieved which have been verified for 2011 and in draft for 2012 from the OPA. Additionally per the CDM code Collus PowerStream is required to annually file an update to the Board which outlines and identifies the progress to year end and any changes which need to be made to the annual targets submitted. Collus PowerStream will be filing with the Board the 2012 annual CDM report which will outline our verified 2011 and 2012 savings and will adjust 2013 and 2014 targets based on changes in programs offered and changes to Collus PowerStream's CDM marketing strategy.

3-Energy Probe-19

Ref: Exhibit 3, Tab 1, Schedule 3

a) **Does Table 3 include actual OPA verified figures for 2012? If not, please update Table 3 to reflect actual data for 2012.**

b) **Please explain the reduction in CDM Target volumes shown for 2012 relative to that for 2011, along with the significant increase forecast for 2013 and then the reduction shown for 2014.**

c) **Why has Collus PowerStream provided 2014 forecasts when 2013 is the test year?**

d) **With respect to Table 4, please explain why forecast figures based on normalized 10-year and 20-year weather data have been provided for 2014 instead of 2013.**

e) **Please update Table 4 to reflect actual data for all of 2012.**

f) **Please update Table 10 to reflect actual data, adjusted for CDM, for each month that is currently available for 2013.**

g) **Please explain how the average 2009-2011 percentages shown in Table 15 have been calculated. For example, how can the 2009-2011 residential average be 40.18% when each of 2009 through 2011 are lower than this figure?**

h) **Please confirm that the service area customer count used in the regression model is actually only the number of residential customers, consistent with the figures shown in Appendix A.**

i) **Please estimate the regression equation that uses the number of residential, GS < 50 and GS > 50 customers as an explanatory variable in place of the customer count used by Collus PowerStream. Please provide the regression data in the same format as Tables 8 and 9, along with the forecast for 2013 as shown in Table 10.**

j) **Please update Tables 14 and 15 to reflect actual data for all of 2012.**

k) What is the impact on the distribution revenue forecast if the average ratios for 2009 through 2011 were used from Table 15, rather than the average of 2005 through 2011, which appears to have been used?

l) Please explain how the monthly forecast of customers used in the regression equation for 2012 (October through December) and for 2013 was determined. In particular, please explain the decrease of 41 customers between September, 2012 and October, 2012.

m) Please provide the actual number of residential customers for each month from October, 2012 through to the most recent month currently available in 2013.

Response

a) Exhibit 3, Tab 1, Schedule 3 Table 3 does not include verified results for 2012. The Ontario Power Authority has not published nor released 2012 verified CDM savings. The 2012 verified CDM savings are not expected to be released until September 2013.

b) Collus PowerStream filed with the Ontario Energy Board the annual CDM report for 2011 in September 2012. In the document Collus PowerStream reviewed 2011 actual verified CDM savings and 2012 unverified savings to date compared to the targets submitted with the strategy document EB-2010-0216. Collus PowerStream revised its targets for 2012-2014 in a thorough review of CDM activity to date and a review of what program adjustments would be required for Collus PowerStream to achieve their board mandated CDM targets.

c) Load forecast was prepared up to December 2014 and all values were included in the tables prepared for the evidence. The correct labelling should read 2012 – Bridge and 2013 – Test. Data for 2014 has not been used in calculating 2013 rates.

d) Please refer to the response for 3-Energy Probe-10 (c). The revised table is presented below.

Table 4
Total System Purchases, MWH

Year	Actual Gross	Model Predicted	Variance, Actual to Predicted, %	Weather-Normal (WN) Actual Gross	Variance, WN Actual to Predicted, %
2005	294,752	296,210	-0.5%	289,266	-2.4%
2006	291,146	288,187	1.0%	295,398	2.4%
2007	295,364	295,876	-0.2%	294,270	-0.5%
2008	298,020	297,103	0.3%	298,755	0.6%
2009	299,265	297,630	0.5%	302,955	1.8%
2010	302,999	305,795	-0.9%	303,509	-0.8%
2011	309,134	308,255	0.3%	310,196	0.6%
2012 Projected	307,430	308,573	-0.4%	311,307	0.9%
2013 Test - Forecast - Normalized 10-year		315,835			
2013 Test - Forecast - Normalized 20-year		315,336			

e) Please refer to the table below.

Table:
Total System Purchases, MWH

Year	Actual Gross	Model Predicted	Variance, Actual to Predicted, %	Weather-Normal (WN) Actual Gross	Variance, WN Actual to Predicted, %
2005	294,752	296,210	-0.5%	289,266	-2.4%
2006	291,146	288,187	1.0%	295,398	2.4%
2007	295,364	295,876	-0.2%	294,270	-0.5%
2008	298,020	297,103	0.3%	298,755	0.6%
2009	299,265	297,630	0.5%	302,955	1.8%
2010	302,999	305,795	-0.9%	303,509	-0.8%
2011	309,134	308,255	0.3%	310,196	0.6%
2012 Actuals	305,842	307,637	-0.6%	310,419	0.9%
2013 Test - Forecast - Normalized 10-year		**315,835**			
2013 Test - Forecast - Normalized 20-year		**315,336**			

f) Please refer to the table below. This table reflects January-June 2013 actual data, including energy purchases, customer count, heating and cooling degree-days, as well as the forecast beyond June 2013 (as per the original evidence).

Table
Monthly Gross Energy Purchases Forecast (kWh)

Month	Forecast	Base Load	Customer Count	CDD	HDD
Model Coefficient		**Varies**	**957**	**31,009**	**13,624**
Jan-13	*30,859,621*		*14,168.00*	*0.0*	*638.9*
Feb-13	*28,903,165*		*14,182.00*	*0.0*	*647.8*
Mar-13	*28,984,499*		*14,191.00*	*0.0*	*582.2*
Apr-13	*25,191,784*		*14,200.00*	*0.0*	*368.7*
May-13	*23,247,272*		*14,216.00*	*15.7*	*163.7*
Jun-13	*23,650,584*		*14,223.00*	*41.0*	*73.3*
Jul-13	24,935,180	8,012,927	14,246.00	102.8	7.9
Aug-13	25,333,288	8,878,437	14,273.00	85.4	11.3
Sep-13	23,029,945	7,445,354	14,301.00	33.8	62.9
Oct-13	24,529,634	7,267,620	14,328.00	6.0	247.4
Nov-13	25,779,669	6,701,033	14,355.00	0.0	392.5
Dec-13	30,560,466	8,373,290	14,383.00	0.0	618.7
Total 2013	**315,005,106**				
Jan-14	32,355,406	8,754,115	14,410.00	0.0	720.6
Feb-14	29,469,489	6,795,097	14,438.00	0.0	650.6
Mar-14	29,403,058	7,729,135	14,466.00	0.0	575.2
Apr-14	24,664,430	6,025,321	14,494.00	2.1	345.7
May-14	23,679,815	6,887,215	14,522.00	7.9	195.0
Jun-14	23,984,324	7,969,762	14,550.00	43.5	54.9
Jul-14	25,252,752	8,012,927	14,578.00	102.8	7.9
Aug-14	25,651,817	8,878,437	14,606.00	85.4	11.3
Sep-14	23,348,475	7,445,354	14,634.00	33.8	62.9
Oct-14	24,849,120	7,267,620	14,662.00	6.0	247.4
Nov-14	26,100,111	6,701,033	14,690.00	0.0	392.5
Dec-14	30,880,908	8,373,290	14,718.00	0.0	618.7
Total 2014	**319,639,707**				

g) The average calculation in Exhibit 3, Tab 1, Schedule 3 Table 15 is a 7 year average for all years.
h) Yes, the service area customer count used in the regression model represents the number of residential customers, which is consistent with the figures shown in Appendix A.

i) Please refer to the tables below

Table
Summary of Monthly Load Forecast Regression Model

Model Statistics	
Iterations	1
Adjusted Observations	88
Deg. of Freedom for Error	73
R-Squared	98.9%
Adjusted R-Squared	98.7%
AIC	25.73
BIC	26.15
Log-Likelihood	-1,241.77
Model Sum of Squares	834,772,894,183,586.00
Sum of Squared Errors	9,305,087,774,172.38
Mean Squared Error	127,466,955,810.58
Std. Error of Regression	357,025.15
Mean Abs. Dev. (MAD)	263,950.60
Mean Abs. % Err. (MAPE)	1.07%
Durbin-Watson Statistic	1.682

Table
Regression Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
Customer Count	885	57	15.41	0.00%
HDD18	13,616	802	16.97	0.00%
CDD18	31,056	2,269	13.69	0.00%
Jan	8,148,398	1,098,144	7.42	0.00%
Feb	6,192,270	1,070,147	5.79	0.00%
Mar	7,124,661	1,029,220	6.92	0.00%
Apr	5,417,339	928,686	5.83	0.00%
May	6,278,426	888,891	7.06	0.00%
Jun	7,359,017	874,181	8.42	0.00%
Jul	7,399,929	894,488	8.27	0.00%
Aug	8,266,118	890,727	9.28	0.00%
Sep	6,839,393	874,049	7.83	0.00%
Oct	6,662,677	910,693	7.32	0.00%
Nov	6,099,568	971,205	6.28	0.00%
Dec	7,775,538	1,062,014	7.32	0.00%

Table
Monthly Gross Energy Purchases Forecast (kWh)

Month	Forecast	Base Load	Customer Count	CDD	HDD
Model Coefficient		**Varies**	**885**	**31,056**	**13,616**
Jan-13	32,041,403	8,148,398	15,902.00	0.0	720.6
Feb-13	29,158,685	6,192,270	15,932.00	0.0	650.6
Mar-13	29,090,958	7,124,661	15,962.00	0.0	575.2
Apr-13	24,349,549	5,417,339	15,991.00	2.1	345.7
May-13	23,365,320	6,278,426	16,021.00	7.9	195.0
Jun-13	23,669,502	7,359,017	16,050.00	43.5	54.9
Jul-13	24,937,721	7,399,929	16,079.00	102.8	7.9
Aug-13	25,335,516	8,266,118	16,108.00	85.4	11.3
Sep-13	23,036,378	6,839,393	16,139.00	33.8	62.9
Oct-13	24,534,234	6,662,677	16,168.00	6.0	247.4
Nov-13	25,786,222	6,099,568	16,197.00	0.0	392.5
Dec-13	30,568,805	7,775,538	16,227.00	0.0	618.7
Total 2013	**315,874,293**				
Jan-14	32,354,864	8,148,398	16,256.00	0.0	720.6
Feb-14	29,473,032	6,192,270	16,287.00	0.0	650.6
Mar-14	29,405,305	7,124,661	16,317.00	0.0	575.2
Apr-14	24,664,781	5,417,339	16,347.00	2.1	345.7
May-14	23,680,552	6,278,426	16,377.00	7.9	195.0
Jun-14	23,986,506	7,359,017	16,408.00	43.5	54.9
Jul-14	25,255,610	7,399,929	16,438.00	102.8	7.9
Aug-14	25,654,290	8,266,118	16,468.00	85.4	11.3
Sep-14	23,354,267	6,839,393	16,498.00	33.8	62.9
Oct-14	24,853,894	6,662,677	16,529.00	6.0	247.4
Nov-14	26,106,767	6,099,568	16,559.00	0.0	392.5
Dec-14	30,889,350	7,775,538	16,589.00	0.0	618.7
Total 2014	**319,679,218**				

As a result of this interrogatory, Collus PowerStream re-estimated the model by utilizing the number of residential, GS<50 and GS>50 customers in place of the customer count used in the model from the original submission As a result of this re-estimate the Total Energy Purchases forecast for the 2013 Test year is 315,874,293 kWh, which is slightly (0.01%) higher than the original forecast. Given that the re-estimate does not alter the model results and the change in the load forecast is minimal, Collus PowerStream is confident that its original load forecast is valid as filed.

j)

Table 14
Customer Growth by Rate Class for Customers Billed kW

Year	GS>50 Customer Growth (%)	Streetlighting Connection Growth (%)
2008	2.48%	2.99%
2009	-10.48%	3.51%
2010	1.80%	-2.71%
2011	3.54%	0.44%
2012	0.00%	0.33%
5 Year average	-0.53%	0.91%

Table 15
Collus Power Historic kWh Allocation by Rate Classes

Year	Residential	GS<50	GS>50	USL	Streetlighting	Total
2005	45.08%	17.48%	36.67%	0.30%	0.80%	100%
2006	44.91%	17.63%	36.72%	0.29%	0.80%	100%
2007	42.26%	17.08%	40.01%	0.20%	0.80%	100%
2008	40.42%	15.26%	43.71%	0.17%	0.80%	100%
2009	35.02%	13.58%	50.27%	0.16%	0.80%	100%
2010	36.30%	14.52%	48.35%	0.14%	0.68%	100%
2011	37.25%	15.10%	46.82%	0.12%	0.84%	100%
2012	38.47%	15.60%	45.12%	0.13%	0.67%	100%
Average 2010-2012	37.34%	15.07%	46.76%	0.13%	0.73%	100%
2013	37.34%	15.07%	46.76%	0.13%	0.73%	100%

k)

Table EP 19k-1 shows the historic allocation of kWhs by Rate Class and the three year average for 2009 through 2011 with the revised billing determinants resulting from the use of the 3 year average for allocation.

Table EP 19k-1: Historic kWh Allocation by Rate Class (2009 to 2011)

Year	Residential	GS<50kW	GS>50kW	USL	Street Lighting	Total
2009	35.19%	13.58%	50.27%	0.16%	0.80%	100.00%
2010	36.31%	14.52%	48.35%	0.14%	0.68%	100.00%
2011	37.12%	15.10%	46.82%	0.12%	0.84%	100.00%
3 YR Average 2009 to 2011	36.21%	14.40%	48.48%	0.14%	0.77%	100.00%
kWh allocation revised	102,891,186	40,921,554	137,769,233	397,848	2,197,639	284,177,461
Billable kWs revised			398,842		5,872	

Table EP 19k-2 shows the resulting impact on forecast variable distribution revenue; fixed monthly charges are unaffected.

Table EP 19k-2: Revised Variable Distribution Revenue based on 3 Year Average

	Residential	GS<50kW	GS>50kW	USL	Street Lighting	Total
Billing Determinant	kWh	kWh	kW	kWh	kW	
Billing Quantity	102,891,186	40,921,554	398,842	397,848	5,872	
Current approved rates	$ 0.0170	$ 0.0113	$ 2.6400	$ 0.0177	$ 14.0054	
Revised Variable revenue at current rates	$ 1,749,150	$ 462,414	$ 1,052,943	$ 7,042	$ 82,241	$ 3,353,789
Variable Revenue as filed	$ 2,005,775	$ 533,203	$ 889,833	$ 7,144	$ 87,226	$ 3,523,181
Change - Increase (decrease)	(256,625)	(70,789)	163,110	(102)	(4,985)	$ (169,392)

l) The monthly forecast for customer growth was estimated, using a 5 year average from 2007-2011. The forecasted growth was calculated using the 5 year average, starting with the December 2011 customer count, through to December 2014. The regression model was run using actual customer data to the end of September 2012 which would account for the small decrease in residential customer count.

m) Please refer to the table below

Table
Number of Residential Customers

	Actual Residential	Original Evidence
Oct-12	14,116	14,002
Nov-12	14,141	14,028
Dec-12	14,156	14,055
Jan-13	14,168	14,082
Feb-13	14,182	14,110
Mar-13	14,191	14,137
Apr-13	14,200	14,164
May-13	14,216	14,192
Jun-13	14,223	14,219

3-Energy Probe-20

Ref: Exhibit 3, Tab 1, Schedule 3 &
Exhibit 3, Tab 2, Schedule 1

a) Based on the explanation provided on pages 19-20 of Exhibit 3, Tab 1, Schedule 3, please show the calculation of the forecasted kW figures for 2013 shown in Table 5 of Exhibit 3, Tab 2, Schedule 1.

b) Please explain the decrease in the number of GS > 50 customers from 117 in 2012 to 114 in 2013, as shown in Table 4 of Exhibit 3, Tab 2, Schedule 1.

Response

a) A review of the billed kW forecasted for 2012 and 2013 should be as follows;

Year		5 Year (2007-2011) Average growth	GS>50 Billed kW	5 Year (2007-2011) Average growth	Streetlighting Billed kW
2011	Actual		371,483		6,048
2012	Actual		378,911		6,186
2013*		-0.86%	338,491	1.34%	6,269
As filed			337,058		6,228
Difference			1,433		41

* 2013 billed kW includes reduction of 0.86% as well the exclusion of a GS>50 customer, demand of 37,161 kW, who filed for bankruptcy in 2012. This customer was also removed from the load forecast.

b) Collus PowerStream GS>50 customer count as reported to the OEB in the RRR 2.1.5 was 117. The 2013 GS>50 customer count should have been reported at 117.

3.0-VECC – 12

Reference: Exhibit 3, Tab 1, Schedule 3, page 2, lines 2-10

a) Please explain more fully why COLLUS has chosen to "add back historical CDM impacts to actual load and then forecast forward". In doing so, please outline the other options considered and why the proposed approach was viewed as being superior.

b) If load forecasts for 2013 were prepared using alternative methodologies, please provide a brief description of the methodology and the resulting forecast.

Response

a) Collus PowerStream used an "add back" methodology (Method 3 below) as was approved by the Board in PowerStream COS 2013 (EB-2012-0161). PowerStream spent a considerable amount of time determining how to integrate the impacts of CDM savings on future loads and determining a robust, effective and accurate methodology to ensure that the load forecast reflects the change from historical levels. Three commonly used forecast methods, explored by PowerStream were:

- Method 1: Forecast using actual load (without any CDM adjustment)**;**
- Method 2: Incorporate CDM impacts as an explanatory variable in the regressions equation; and
- Method 3: Add back historical CDM impacts to the actual load and then forecast forward.

Given that the impact from past CDM savings is small in relation to the actual loads and the regression statistics are comparable across all three methods, the choice between methods was simply based on judgement in assessing the advantages and disadvantages of each approach.

Method 3 was considered the most robust since it accounts for historic and future CDM effects, based on the assumption that the reported validated CDM numbers represent real CDM savings. As such, if these numbers are equivalent to actuals, the actual loads can be adjusted to the levels they would be without any CDM activities, therefore using this as the true trend to forecast forward. This approach allows PowerStream to evaluate the impact of CDM on load to better reflect forecast trends for future load growth.

b) The goal of a multiple regression forecast model is to produce the most accurate forecast possible, given available information on the factors that affect monthly energy purchase variation and growth. Several monthly models of energy purchases were specified, estimated and tested to derive the energy purchases forecast. Alternative purchase models were specified where Customer Count was replaced with Ontario Real GDP, Energy Price and a variable that is a 50/50 weighting of these two variables, as well as utilizing the Trend variable. Table below compares the model results.

Table VECC-12-1: Model Comparison

	Model 1	Model 2	Model 3	Model 4	Model 5	Model 6
Constant	**n/a**	17,711,609	14,790,988	16,080,948	18,119,746	6,287,742
Independent Variables						
Heating Degree-days (HDD18)	**13,624**	15,098	15,305	15,225	14,965	15,155
Colling Degree-days (CDD18)	**31,009**	44,607	44,093	44,411	44,797	45,038
Real Gross Domestic Product for Ontario (GDP)		188,085				
Customer Count for service area	**957**					1,002
Energy Price			70,171,452			
GDP/Energy price (weighted variable)				7,514,478		
Simple Trend					290,743	
Jan	**8,754,115**					
Feb	**6,795,097**					
Mar	**7,729,135**					
Apr	**6,025,321**	(1,412,026)	(1,349,905)	(1,387,702)	(1,347,884)	(1,388,600)
May	**6,887,215**					
Jun	**7,969,762**					
Jul	**8,012,927**					
Aug	**8,878,437**					
Sep	**7,445,354**					
Oct	**7,267,620**					
Nov	**6,701,033**					
Dec	**8,373,290**					
Model Statistics						
Adjusted R-Squared	**98.70%**	94.00%	94.50%	94.20%	95.10%	95.30%
MAPE, %	**1.07%**	2.56%	2.50%	2.44%	2.17%	2.25%
Out-of-Sample MAPE, %	**1.13%**	2.18%	2.21%	2.19%	2.02%	2.12%
2013 Test Energy Purchases (kWh)	**315,834,571**	**314,921,272**	**315,018,169**	**313,797,836**	**316,034,616**	**316,107,614**

NOTE: all selected variables are statistically significant at the 5% level of confidence.

As Table shows, all models fit the historical data well with some differences in Adjusted R-Squared and MAPE. Yet, Model 1 using Customer Count as a proxy for economic activity had the strongest fit with an adjusted R-squared of 98.7% and performed better in the in- and out-of-sample tests (1.07% and 1.13% respectively).

Model 1 generated a reasonable forecast of 0.6% average annual purchases growth (net of CDM), which is in line with the weather-normalized net load growth over the past 3 years (2010-2012) of 0.6%.

3.0 – VECC – 13

Reference: Exhibit 3, Tab 1, Schedule 3, pages 3 – 4

a) With respect to Table 1, please provide the OPA reports that substantiate the values reported for years 2005-2011 under the “OPA Programs” column.

b) Please reconcile the 3,194,455 kWh attributed to 2011 CDM programs in 2011 per Table 1 with the 820,000 kWh OPA-verified value reported in Exhibit 3, Tab 1, Schedule 5, Appendix A.

c) Please reconcile the differences between the loss factors used in Table 2 and those shown at Exhibit 8, Tab 1, Schedule 8, page 1 for the years 2007-2011.

d) With respect to Table 3, please explain more fully how the CDM Targets values were determined for each of the years 2011 to 2014 inclusive.

e) If not provided in response to part (d), please provide the source of the 2011-2014 values shown for “OPA Programs”.

Response

a) Collus PowerStream uploaded to RESS report 2006-2010 Final OPA CDM Results COLLUS Power Corporation.xls

b) As per the report in Exhibit 3, Tab 1, Schedule 5, Appendix A, the 2011 savings were 820,000 kWh. As the CDM code accumulates and assumes persistence of savings over the lifespan of the code, 2011 – 2014, the total savings 2011, including persistence, is 3,194,455 kWh as shown in Appendix A under Verified Net Cumulative Energy Savings 2011-2014.

c) The loss factors applied in Exhibit 3, Tab 1, Schedule 3, Table 2 are the loss factors applied to Collus PowerStream customers as per the approved tariff sheets. The loss factors in Exhibit 8, Tab 1, Schedule 8, Table 1 are actual loss factors which have been used to derive the proposed loss factor for 2013 rates and forward.

d) In 2010 Collus PowerStream filed its CDM Strategy document EB-2010-0216 with the OEB which outlines the process of forecasting Collus PowerStream's OEB mandated CDM targets.

   In September 2012 Collus PowerStream filed with the OEB, as per the CDM Code, its Annual CDM Report for 2011. This report summarized Collus PowerStream's progress to date as well re-evaluated the target forecasts for 2012-2014 based on actual 2011 progress.

e) Collus PowerStream uploaded to RESS 3.0-VECC-13_c_Collus PowerStream Annual CDM Report for 2011.pdf

3.0 – VECC – 14

Reference: Exhibit 3, Tab 1, Schedule 3, page 11 (lines 13-15)
Exhibit 3, Tab 1, Schedule 4, page 1

a) In Schedule 4, are the "Actual Normalized" customer/connection counts shown for 2012 actual values or forecast values?
b) If they are forecast values, please provide the actual 2012 customer/connection counts by class.
c) Are the customer/connection counts shown, average annual or year-end values?
d) Please provide a schedule that sets out the historical customer/connection count data referred to in Schedule 3 and the calculation of the historical growth rates used to determine the 2013 customer/connection count.

Response

a) The numbers provided for 2012 in Exhibit 3, Tab 1, Schedule 4 are forecasted.
b) Collus PowerStream has updated the forecasted 2012 numbers with actual 2012 results.

	Number of Customers (Connections)									
	Board Approved 2009 #	Actual 2009 #	Actual Normalized 2009 #	Actual 2010 #	Actual Normalized 2010 #	Actual 2011 #	Actual Normalized 2011 #	Forecast 2012 #	Actual Normalized 2012 #	Forecast 2013 #
Residential	13,011	12,979	12,979	13,402	13,402	13,665	13,665	14,156	14,156	14,233
GS Less Than 50 kW	1,588	1,611	1,611	1,646	1,646	1,672	1,672	1,703	1,703	1,717
GS 50 to 4,999 kW	128	116	116	117	117	117	117	117	117	114
Unmetered Scattered Load	68	32	32	31	31	30	30	30	30	30
Street Lighting	3,051	3,040	3,040	2,982	2,982	2,978	2,978	3,005	3,005	3,045
TOTAL	**17,846**	**17,778**	**17,778**	**18,178**	**18,178**	**18,462**	**18,462**	**19,010**	**19,010**	**19,139**

c) The customer count values are actual as at December 31.

d)

Historical Customer Connection Count

Month/Yr	Residential	GS < 50	GS >50	Large user	Unmetered	Street lightin	Street lighting (connections)	
Actual customer count at year end								
12/02	11420	1515	108	2	150	3	2479	15674
12/03	11756	1524	114	2	154	3	2517	16067
12/04	11934	1536	115	2	158	3	2715	16460
12/05	12142	1537	119	2	100	3	2750	16650
12/06	12242	1554	123	1	95	3	2806	16821
12/07	12535	1567	121	1	85	3	2875	17184
12/08	12771	1578	124	1	76	3	2961	17511
12/09	13140	1590	111		32	3	3065	17938
12/10	13549	1663	113		30	3	2982	18337
12/11	13735	1677	117		30	3	2995	18554
12/12	14156	1703	117		30	3	3005	19011
Forecast 12/12	14074	1705	116		30	3	3022	18947
Forecast 12/13	14503	1732	116		30	3	3032	19414

Historical Growth Rates

	Residential		GS < 50		GS > 50		Unmetered		Street light connections	
	Increase #	Increase %	Increase #	Increase %	Increase #	Increase %	Increase #	Increase %	Increase #	Increase %
2007	293	2.39%	13	0.84%	-2	-1.63%	-10	-10.53%	69	2.46%
2008	236	1.88%	11	0.70%	3	2.48%	-9	-10.59%	86	2.99%
2009	369	2.89%	12	0.76%	-13	-10.48%	-44	-57.89%	104	3.51%
2010	409	3.11%	73	4.59%	2	1.80%	-2	-6.25%	-83	-2.71%
2011	186	1.37%	14	0.84%	4	3.54%	0	0.00%	13	0.44%
2012	421	3.07%	26	1.55%	0	0.00%	0	0.00%	10	0.33%
5 year average		2.46%		1.69%		-0.53%		-14.95%		0.91%
Forecast										
2012	339		28		-1		0		27	
2013	347		29		-1		0		27	
2014	355		29		0		0		28	
2015	364		30		0		0		28	
2016	373		30		0		0		28	
2017	382		31		0		0		29	

3.0 – VECC – 15

Reference: Exhibit 3, Tab 1, Schedule 3, page 18 (Table 13)

a) Please provide the Normalized 20-year value for 2013.

Response

a) Please refer to the table below.

Table 13

Energy Purchases Net of CDM

Year	Actual Gross	CDM Reduction	Actuals	WN Actual Gross	WN Actual Net	Growth, %
2005	294,752	173	294,579	289,266	289,093	
2006	291,146	2,459	288,687	295,398	292,940	1.3%
2007	295,364	3,270	292,094	294,270	291,000	-0.7%
2008	298,020	4,117	293,903	298,755	294,639	1.3%
2009	299,265	6,043	293,222	302,955	296,912	0.8%
2010	302,999	6,557	296,442	303,509	296,952	0.0%
2011	309,134	9,559	299,575	310,196	300,636	1.2%
2012	307,430	8,864	298,566	311,307	302,443	0.6%
2013 Test - Normalized 10-year		**11,492**		**315,835**	**304,343**	**0.6%**
2013 Test - Normalized 20-year		**11,492**		**315,336**	**303,844**	**0.5%**

3.0 – VECC – 16

Reference: Exhibit 3, Tab 1, Schedule 3, pages 5 and 19-20

a) Page 5 states that kW units for the relevant customer classes were determined based on the historic relationship between kWh and kW. However, page 20 suggests the kW values were determined by applying the average historic customer growth to the historic kW value. Please reconcile and clarify how the kW values were actually forecast.

b) Please provide a schedule that for each of the GS>50 and Streetlighting classes sets out the historical values for kW and kWh (2007-2011) along with the resulting annual kW/kWh ratios and the resulting overall historical average for each class. Note: For GS<50 please exclude Nacan/Amaizeingly Green data from the calculations.

c) Based on the historical average from part (b) and the 2013 forecast kWh for GS>50 and Streetlighting, please calculate 2013 kW for each class.

Response

a) Collus PowerStream determined, as per Exhibit 3, Tab 1, Schedule 3, page 20, kW values by applying the average historic customer growth to historic kW values.

b)

Conversion of kWhs to billed kW demand GS>50 kW demand class:									
Year	Actual kWhs	AGP	Revised kWhs		Billed kWs	AGP	Revised Billed kWs	Ratio: kWhs per kW	Ratio: kWs per kWh
2010	151,062,848	35,346,742	115,716,105		396,534	57,338	339,196	341.1478	0.002931
2011	144,641,442	30,427,145	114,214,297		371,481	52,518	318,963	358.0795	0.002793
Actual 2012	137,932,990	22,067,605	115,865,385		378,911	36,052	342,859	337.9387	0.002959
Total	**433,637,280**	**87,841,492**	**345,795,787**		**1,146,926**	**145,907**	**1,001,019**	345.4438	0.002895
Forecasted 2013	**116,434,672**						**337,058**		

Streetlighting									
Year	Actual kWhs				Billed kWs			Ratio: kWhs per kW	Ratio: kWs per kWh
2010	2,289,263				5,980			382.8199	0.002612
2011	2,313,894				6,049			382.5250	0.002614
Actual 2012	2,212,989				6,187			357.6837	0.002796
Total	**6,816,146**				**18,216**			374.1846	0.002672
Forecasted 2013	**2,166,298**				**5,789**				

c) See 3.0-VECC-16 b)

3.0 – VECC – 17

Reference: Exhibit 3, Tab 1, Schedule 3, page 20

a) Please explain why a 3-year average was used in Table 15.

b) Do the values used in Table 15 exclude Nacan/Amaizeingly Green? If not, please re-do the table excluding this data.

Response

a) The average calculation in Exhibit 3, Tab 1, Schedule 3, Table 15 is a 7 year average calculation. The chart incorrectly indicates a 3 year average calculation.

b) Exhibit 3, Tab 1, Schedule 3, Table 15 excludes Nacan/Amaizeingly Green.

3.0 – VECC – 18

Reference: Exhibit 3, Tab 1, Schedule 3, Appendix A

a) The Application states that the data for Nacan/Amaizeingly Green was excluded for purposes of the regression analysis. Has the forecast for 2013 been adjusted at all to reflect the fact that the going forward operations for the former Amaizeingly Green facility are expected to be at 15% of full plant operations? If not, what would be impact?

Response

a) The load forecasts provided do not include any historical nor any forecasted loads for Nacan/Amaizeningly Green (now AG Global). Amaizeningly Green filed for bankruptcy in December 2012. When operating at peak capacity, approximate demand of 4.9 MW, Amaizeningly Green produced ethanol. Ethanol production at the facility ceased in July of 2012. Currently the facility is not in operation. Demand at the facility currently is approximately 6% of peak capacity. The future of the plant is unknown at this time and due to the significant impact the loss of this facility would impose on the load forecast it has been excluded from the load forecast.

3-Energy Probe-21

Ref: Exhibit 3, Tab 1, Schedule 5

The evidence indicates that since the balance in account 1568 is immaterial, Collus PowerStream is not applying for the disposition of the balance at this time. Does this mean that Collus PowerStream will forgo recovery of the balance for 2011 programs or that it will recover this amount in a future application?

Response

Collus PowerStream is not forgoing the recovery but will request recovery in a future application.

3.0 – VECC – 19

Reference: Exhibit 3, Tab 1, Schedule 5, pages 1-2

a) How were the 2011 actual kWh savings apportioned between Residential and the GS classes? Please provide as schedule that sets out the determination of the assignment.
b) The Application states that the assignment as between GS<50 and GS>50 was based on number of customers. Total savings for 2011 are reported as 820,000 kWh and the savings attributed to Residential and GS<50 were 475,192 kWh. This suggests that the savings attributed to GS>50 were 344,808 kWh which is more than the total kWh assigned to GS<50 of 195,812 kWh). Please reconcile the relative kWh savings values for GS<50 and GS>50 with the fact the 2011 customer count for the former is more than 10x that of the latter customer class.
c) Please provide a schedule that sets out the assignment of the 2011 actual kWh savings as between GS<50 and GS>50 and show how the 60 kW savings value for GS>50 was determined.
d) In Table 2, what is the basis for the allocation %'s used?

Response

a) The chart below shows the kWh and kW breakdown between residential, GS<50 and GS>50 customers.

2011 Programs only

Source: OPA Final 2011 Report

Energy Savings 2011 Programs

Demand Savings 2011 Programs

Initiative Name		Net Annual kW Savings	Net Annual kWh Savings	*Res*	*GS <50*	*GS>50*		Total kWh		GS>50	Total kW
Fridge Pick Up		9	54,418	***100%***				54,418			
HVAC Rebates		46	87,511	***100%***				87,511			
Coupons (and retailers events)		8	137,451	***100%***				137,451			
Peaksaver		0	0	***100%***				-			
Retailer Co-Op/Sears		0	0	***100%***				-			
								-			
CONSUMER TOTAL		**63**	**279,380**				*Total Resident*	279,380			
									GS>50 kwh		
Multi-Family efficiency rebates		0	0	***100%***				-			
Efficiency: equipment replacement		16	116,644		*25%*	*75%*		29,161	87,483	75%	11.74
ERIP		3	20,487		*25%*	*75%*		5,122	15,365	75%	2.17
Direct Installed Lighting		61	161,529		*100%*			161,529	-		
New Construction and Major Renovation		0	0		*0%*	*100%*		-	-	100%	-
C&I TOTAL		**79**	**298,660**								
2010 ERIP		3	15,807			***100.0%***		-	15,807	100%	2.72
High performance New Construction		44	225,075			*100%*		-	225,075	100%	43.82
Data Centre Incentive program		0	0		*0%*	*0%*		-	-	0%	-
2010 Programs Total		**47**	**240,882**				*Total GS <50*	195,812	343,730		
DR3 Industrial		0	0						-		-
DR3 Industrial		37	1,451						1,451		
INDUSTRIAL TOTAL		**37**	**1,451**						1,451	Total GS>50	**60.45**

Total For LRAM: **475,192**

Consumer Total from the report	63	279,380
Check to source	-	-
Business and Industrial total from report	116	300,111
Check to source	-	-
2010 Programs	46.5	240,881.9
	-	-
Total	225.5	820,373.6

b) Collus PowerStream reviewed all commercial and institutional and industrial programs to determine which customer class savings should be attributed to. As result it was deemed that approximately 25% of the 2011OPA Efficiency: equipment replacement and ERII projects were completed by GS<50 customers leaving the remaining 75% completed by GS>50 customers. Additionally all 2010 projects completed in 2011 were attributed to GS>50 customers. As indicated above the total kWh savings attributed to GS>50 customers was 345,181 kWh. As indicated there are more than 10 times as many GS<50 customers as GS>50 customers. What needs to be noted is that GS<50 customers generally participate in the Small Business Direct Install program which generally provides for smaller kWh and kW savings. GS<50 only occasionally participate in the ERII program. Conversely GS>50 customers can only participate in the ERII program and those projects are larger in scale and the kWh and kW savings are significant.

c) As indicated above the majority of the savings, kWh and kW, not attributed to residential were attributed to the GS>50 customer class. See 3-VECC-19 a).

d) Collus PowerStream used the class allocation %'s used for the load forecast to allocate savings to th classes.

3.0-Staff-19

Ref. E3/T2/S1, Attachment 1, Table 2– Other Revenue

a. Please provide the up-to-date balances in these accounts to the same level of detail as shown in Table 2.

Response

a. The reference appears wrong for this question on other revenue.
It should be E3/T3/S1 – Table 2 Details of Other Operating Revenue.

		June 2013
	Other Revenue:	
4078	4080-0000-01 SSS Charge - Distribution Service Revenue	22,375.94
	4082-0000-00 Retail Service Revenues	8,050.00
	4084-0000-00 Service Transaction Requests	204.25
	4210-0000-00 Rent From Electric Property	52,500.00
	4225-0000-00 Late Payment Charges	45,322.11
	4235-0000-00 Miscellaneous Service Revenues	26,853.13
	4235-0000-01 Change Of Occupancy Charge Rev	27,950.00
	4235-0000-02 Disconnect/Reconnect Revenue	22,574.00
	4235-0000-03 Collection Services Revenue	
	4235-0000-04 MicroFit Administration Revenue	
	4355-0000-00 Gain on Disp of Util & Propert	
	4375-0000-00 Revenues from Non-Utility Operation	5,451.88
	4380-0000-00 Expenses of Non-Utility Operations	
	4390-0000-00 Misc Non Operating Income	7,684.50
	4405-0000-00 Interest & Dividend Income	23,412.78
	Total Other Revenue	242,378.59

3.0 – VECC – 20

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

a) In Table 6, please explain how the actual normalized values were determined for the years 2009-2011.
b) What do the values in the “Forecast 2012” column represent – are they forecast or actual values? If forecast, please provide the actual values for 2012.
c) What do the values in the “Actual Normalized 2012” column represent? If they are based on actual 2012 values, please explain how they were “weather normalized”.
d) Please explain why for the Streetlighting and USL classes (which are weather insensitive) the actual values for 2009-2011 differ from the weather normalized values.

Response

a) As per the evidence in Exhibit 3, Tab 1, Schedule 3 beginning page 7,

“COLLUS PowerStream normalizes energy purchases using a “use per degree” methodology. This methodology uses the weather-related coefficients in the regression equation to estimate normalized volumes. The difference between actual and normal degree-days is determined. The weather related coefficients are applied to that difference to derive weather-sensitive volume. Actual volumes are adjusted by the weather sensitive volume.
The formula is:
Normalized Volume = Actual Volume – (Actual HDD or/and CDD – Normal HDD or/and CDD) x Corresponding Regression Coefficient”

b) The values in Forecasted 2012 are actual at December 31, 2012.

c) The values in 2012 Forecast are 2012 Normalized Actuals up to September 2012 and forecasted for October to December 2012 which are weather normalized. These balances were normalized using the process as described in 3.0-VECC-20 a).

d) Collus PowerStream normalizes total energy purchases using a “use per degree” methodology. This methodology uses the weather-related coefficients in the regression equation to estimate total normalized volumes. The difference between actual and normal degree-days is determined. The weather related coefficients are applied to that difference to derive weather-sensitive volume. Actual volumes are adjusted by the weather sensitive volume. These adjusted total volumes were allocated to rate classes as based on the average percentages. Actual values for 2009-2011 differ from the weather-normalized values, since allocation to classes is performed after the historic actual total load is weather-normalized.

This methodology was approved by the Board in PowerStream COS 2013 (EB-2012-0161).

Collus PowerStream is not convinced that the Street Lighting and USL classes are totally weather insensitive.

3.0 – VECC – 21

Reference: Exhibit 3, Tab 3, Schedule 1, pages 2-4

a) Does COLLUS have any microFIT customers? If so, how many and where is the revenue from the associated monthly service charge included in Table 2?
b) In Table 2, SSS Admin Charge revenue is reported separately for 2011 (Account 4078). Where is the SSS Admin Charge revenue reported for the other years and what is the forecast revenue for 2013?
c) Does the Interest and Dividend Income reported (Account 4405) include any interest associated with deferral/variance accounts? If yes, what are the amounts for 2011 – 2013 inclusive?
d) Please explain why the total Specific Service Charges revenue reported in Table 3 does not match the revenues reported for Account 4235 in Table 2.
e) Exhibit 3, Tab 3, Schedule 2, page 1 explains the high level of Late Payment Charge revenues in 2011 and 2012 and suggests that 2013 will be return to normal historic levels. However, the forecast for 2013 is $84,000 as compared to average revenue in 2009-2010 of $92,000. Please reconcile.

Response

a) At the end of 2012 Collus PowerStream had 33 MicroFIT and 1 FIT customer. The monthly service charge revenue has been included in account 4080 Distribution Service Revenue.
b) Please refer to Energy Probe IR (3-Energy Probe-22, Part b)
c) No the Interest and Dividend Income reported (Account 4405) does not include any interest associated with the deferral/variance accounts. We track interest on deferral/variance accounts in a subaccount of 6035.
d) Please refer to Energy Probe IR (3-Energy Probe-22, Part e)
e) The forecast for 2013 Late Payment Charges is $84,000 as compared to average revenue in 2009-2010 of $92,000. This results in an $8,000 insignificant difference. Considering the loss of more than a few industrial customers since 2009 it is reasonable to conclude that while Late Payment Charges will be returning to the range of historical levels, a slight decline is management’s best expectation. Please refer to Energy Probe IR (3-Energy Probe-22, Part c) which also contains information on a similar query.

3-SEC-8

[Ex/3/3/1/p.2]
Please expand Table 2 to include 2013 year-to-date actuals.

Response

Please refer to 3-Energy Probe-22, part f

3-SEC-9
[Ex/3/3/1/p.2]
Please explain why there is no Gains on Disposition of Utility and Other Property for the Test Year, considering the Applicant is seeking to purchase a number of new vehicles.

Response

Please refer to 3-Energy Probe-22, part g

EXHIBIT 4 – OPERATING COSTS

4.0-Staff-21

Ref: E4/T1/S1, p.7 – Donations

On page 7, Collus PowerStream states that "donations in the 2013 test year have not yet been determined… Collus PowerStream has in the past made donations to charities that have a direct benefit to customers (such as the local hospital). As a result in the Test Year, the donations made by Collus PowerStream have been included in regulatory OM&A expenses due to their expected nature.

a) Please confirm that all donations have been included in account 6205. If not, please explain

b) Please provide the up-to-date amounts of donations for the 2013 test year.

c) Please provide a breakdown of this account.

Response

a) All donations for 2011 forward have been included in account 6205. Prior to 2011 the 6205 donation account was never used in the accounting system. Donations in 2009 and 2010 would have been included in various general & administration accounts. The 2011 actual donations of $4,495 would approximate the 2009 and 2010 expenditure.

b) Up-to-date donations for the 2013 test year follow.

c) A break-down between donations and LEAP has been provided below.

	Actual YTD *June 2013*	Forecast *2013*	*2012*	*2011*	*2010*	*2009*
Other - Donations & Leap:						
6205-0000-00 Donations	2,215.45	21,000.00	25,225.00	4,495.00		
6205-0001-00 Low-Income Energy Assistance Program	10,465.00	10,465.00	7,693.00	5,864.90		
	-------------	--------------	--------------	--------------	--------------	--------------
Total Other - Donations & Leap	12,680.45	31,465.00	32,918.00	10,359.90		
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EXHIBIT 4 - OPERATING COSTS

4.0-Staff-22

Ref: E4/T1/S1, Table 2 and E4/T1/S2, p.2 – Regulatory Costs

Collus PowerStream has included a total cost of $81,000 for the 2013 test year, which is an increase of approx. 174% or $51,485 over 2009 Actual. Included in this cost is an expert witness for the amount of $20,000. On page 2 of E4/T1/S2, p. 2 Collus PowerStream cites “reduce[d] costs through expertise in the area of regulatory issues and implementation” due to the Acquisition of 50% of the Shares of Collingwood utility Services Corp. by PowerStream Inc. in the summer of 2012.

a) Please explain the nature and need for an expert witness.

b) Please provide a breakdown and details of the cost for external consultants.

c) Please state if and what efficiency gains Collus PowerStream has been able to realize as a result of the acquisition by PowerStream Inc. If so, please provide details and the impact on regulatory costs. If not, please explain why not.

Response

a) Appendix 2-M Regulatory Cost Schedule shows $20,000 for the test year required for expert witnesses for regulatory matters. This expenditure is required for experts in shared services agreements, the Affiliate Relationship Code, Asset Management Planning.
b) Appendix 2-M Regulatory Cost Schedule shows $147,794 for consultants related to regulatory matters. As at June 30, 2013 we have exceeded this forecast by $47,306 and additional costs are yet to be incurred.

   Outside consultants were required due to the departure on September 28, 2012 of the previous CFO and the departure of the regulatory manager on December 31, 2010. Therefore, the loss of these key staff resulted in necessary outside resources.

Regulatory Consultants Costs from 2012 up to June 30, 2013

Asset Management Pan	11,000.00	Automated Solutions Int'l Inc.
Cost of Service Preparation	126,400.00	Greg Van Dusen Utility Consulting Inc
Shared Services Study	12,000.00	Howard Gorman - 'HSG Group, Inc.
Board Reporting and Application Oversight	16,500.00	Edward Chatten - Energy Consulting Services
Cost Allocation & Rate Design	29,200.00	Dave Proctor - Utility Financial Concepts Inc.

Total	195,100.00

c) E4/T1/S2 page two states, “It is anticipated that the relationship will reduce costs through expertise in the area of regulatory issues and implementation”. Page three continues to say, “Although **savings are not quantifiable at this time** Collus PowerStream believes that the partnership will assist in **future** **mitigation** of upward pressure on distribution rates.”

The PowerStream deal was dated July 31st, 2012 with final closing not until March 1, 2013. Therefore, it would not be reasonable to have any expectations that efficiency gains on this cost of service application could be realized. It is anticipated that the next future cost of service application will show reduced costs in regulatory expenses. However, it is too premature to determine what those savings will be.

That being said, we have used the expertise of a number of PowerStream employees in our current cost of service process and utilized their administrative resources for putting together the final submission.

Please refer to the response for interrogatory 1-Energy Probe-4.

4-Energy Probe-23

Ref: Exhibit 4, Tab 1, Schedule 1, page 1 and page 5

a) What was the smart meter costs charged to OM&A in 2012 as a result of EB-2012-0017 ($315,000 as indicated on page 1 or $325,000 as indicated on page 5)?

b) Please provide a breakout of the smart meter costs charged to OM&A in 2012, into the years in which the costs were incurred.

c) Is the amount included in 2013 OM&A related to the 'on-going' nature of smart meter costs (page 1) the $240,000 noted on page 5?

Response

a) The smart meter costs charged to OM&A in 2012 as a result of EB-2012-0017 is indicated as approximately $315k on page 1 and $325k on page 5. There is a typo on page 1, which should read $325k not $315k. (The exact figure is $324,044 as noted in 1-Energy Probe-6.

b) This question is a repeat of 1-Energy Probe -6. Please refer to the previous response.

c) Yes, the amount included in 2013 OM&A related to the 'on-going' nature of smart meter costs (page 1) is the $240,000 noted on page 5. Please refer to 4.0-Staff-24 for more details.

4-Energy Probe-24

Ref: Exhibit 4, Tab 1, Schedule 1, pages 7-9

a) Please explain the statement that donations in the 2013 Test Year have not yet been determined, along with the statement that Test Year donations made by Collus PowerStream have been included in regulatory OM&A expenses due to their expected nature.

b) Table 3 includes $31,465 in donations for 2013, of which $9,100 is identified as LEAP funding (page 9). Please provide a breakdown of the remaining $22,365 and indicate why ratepayers should pay for these donations rather than the shareholders.

c) Please confirm that Collus PowerStream has the one-time regulatory costs associated with this application, totaling $254,394 (Table 2) over 4 years, and not the total regulatory costs of $366,600, which include ongoing costs. If this cannot be confirmed, please explain why ongoing costs should be amortized.

d) Please reconcile the regulatory costs shown in Table 2 with the $81,000 figure shown in Appendix 2-G in Account 5655.

Response

a) The statement that donations in the 2013 Test Year have not yet been determined means we have not determined to whom the funds will be specifically allocated. The intent is that charitable donations will go to organizations such as the hospital which we did in 2012 or other programs that provide assistance to our customers in paying their electricity bills and assistance to low income consumers.

The statement that Test Year donations made by Collus PowerStream have been included in regulatory OM&A expenses due to their expected nature, means that we have reviewed our intentions for the use of the donations and feel they will all be recoverable contributions and therefore have included them in OM&A. We have not planned any political donations which need to be removed.

b) Table 3 includes $31,465 in donations for 2013, of which $9,100 is identified as LEAP funding and 1,365 is LEAP administration fee paid to the Housing Resource Centre to facilitate the LEAP disbursements. The remaining 21,000 has not been determined to whom the funds will be specifically allocated. The intent is that charitable donations will go to organizations such as the hospital which we did in 2012 or other programs that provide assistance to our customers in paying their electricity bills and assistance to low income consumers.

c) Yes, Collus PowerStream has estimated one-time regulatory costs associated with this application, totaling $254,394 (Table 2) to be amortized over 4 years. The regulatory cost total shown of $366,600, also includes ongoing costs which are expensed as incurred.

d) Please reconcile the regulatory costs shown in Table 2 with the $81,000 figure shown in Appendix 2-G in Account 5655.

One-Time (254,394 / 4 years)	63,598.50
On-Going	112,206.00
Less: One-Time Costs only partial claim in 2013 - not full year of rates	(25,000.00)
Less: Operating resources associated with staff posted to 5615	(70,000.00)
Total to account 5655 per year	80,804.50
Amount recorded in the budget for 5655	81,000.00
	(195.50)

4-Energy Probe-25

Ref: Exhibit 4, Tab 1, Schedule 1 & Appendix 2-G

a) **Do the figures shown in Table 1 of Exhibit 4, Tab 1, Schedule 1 and in Appendix 2-G include final actual audited figures for 2012?**

b) **If the response to part (a) is no, please provide an updated Table 1 and Appendix 2-G that incorporate final audited figures for 2012.**

Response

a) Yes, the figures shown in Table 1 of Exhibit 4, Tab 1, Schedule 1 and in Appendix 2-G include final actual audited figures for 2012.

b) The response to part (a) was yes, so no updated Table 1 and Appendix 2-G have been provided.

4-SEC-10

[Ex.4/1/1/p.2]
Please provide a copy of the Applicant's collective agreement with the IBEW.

Response

A copy of the Agreement is provided below. The "Water Department" wage rates in Schedule A have been redacted as they are not relevant to this proceeding.

<u>COLLECTIVE AGREEMENT</u>

Between

<u>COLLUS Power Corp. and Collingwood Public Utilities</u>

of the

<u>TOWN OF COLLINGWOOD</u>

And

ITS' EMPLOYEES THROUGH LOCAL #636 OF THE INTERNATIONAL BROTHERHOOD OF ELECTRICAL WORKERS

<u>SEPTEMBER 1ST, 2010 TO AUGUST 31st, 2013</u>

IBEW
LOCAL 636
CANADA

Table of Contents

This agreement entered into this 14th day of January 2011
Between

COLLUS Power Corp. and
Collingwood Public Utilities
hereinafter referred to as the "Corporation"

and

Local Union 636 of the International Brotherhood of Electrical Workers

hereinafter referred to as the "Union"

ARTICLE 1 - PREAMBLE AND PURPOSE

1.01 The general purpose of this agreement is to establish and maintain orderly collective bargaining relations between the Corporation and its employees, to make provision for prompt and equitable disposition of grievances and to establish and maintain satisfactory working conditions, hours of work and wages for all employees who are subject to the provision of the agreement.

1.02 Whenever the singular, masculine or feminine is used in this agreement, it shall be considered as if the plural, feminine or masculine has been used where the context of the party or parties so requires.

ARTICLE 2 - MANAGEMENT'S RIGHTS

2.01 The Union acknowledges that the Corporation has the exclusive right to manage its business and direct the working force, make, amend and enforce such rules and regulations as shall from the time be required consistent with the terms of this agreement.

ARTICLE 3 - RECOGNITION

3.01 The Corporation hereby recognizes the Union as the sole collective bargaining agent for all employees of the Corporation save persons above the rank of foreman, office staff, students employed during the school vacation period, on a co-operative training program or persons employed on a government sponsored program and persons regularly employed for not more than twenty-four (24) hours per week. The work that these workers perform shall involve only non-union positions.

3.02 The words "employee" or "employees" wherever used in this agreement shall mean only the employees in the bargaining unit defined above unless the context otherwise provides.

ARTICLE 4 - RELATIONSHIP

4.01 The employer shall advise the Union Steward or designate of all hiring and lay-offs. The Steward or designate shall also be advised within five (5) working days of all discharges, suspensions and letters of discipline except where the employee concerned specifically directs the Corporation **not** to advise the Union.

ARTICLE 5 - CORPORATION SERVICE CREDIT

5.01 Credit for Corporation service shall accrue to regular employees whether or not they are members of the bargaining unit. Corporation Service Credit shall be defined as the length of continuous service an employee has established with the Corporation from the most recent date of hire by the Corporation.

5.02 An employee shall lose all accumulated Corporation service credit and his/her name shall be removed from Corporation records if he/she:

(a) Terminates voluntarily;

(b) is discharged and is not reinstated through the grievance and arbitration procedures;

(c) retires;

(d) is laid off for a period of twelve (12) consecutive months or more;

(e) fails to return to work after lay-off within five (5) working days of recall, notice of which has been mailed to the last address the employee has reported to the Corporation;

(f) is permanently disabled and unable to work for the Corporation in a job classification in which there is a job available after a period of two (2) years have expired;

(g) is absent and on workers' compensation for a period of more than twenty-four (24) months.

5.03 When an employee loses accumulated service credit and his/her name is removed from the Corporation record, all employee benefits shall cease and a break in service be deemed to have occurred. Exception to this is provided for in Section 16.04.

ARTICLE 6 - UNION SECURITY AND CHECK-OFF

6.01 During the term of this agreement, the Corporation agrees to deduct from the wages of each employee a sum of money equal to the monthly membership dues as established by Local #636, International Brotherhood of Electrical Workers, and remit same to the Financial Secretary of the Union before the end of each current month. The Corporation shall also deduct the initiation fee from all new employees once they have finished probation. The initiation fee shall be forwarded to the Local Union 636, IBEW office along with their dues deduction as described in the Local Union by-laws.

6.02 In consideration of this deduction and forwarding service by the Corporation, the Union agrees to indemnify and save the Corporation harmless against any claim or liability arising out of or resulting from the collection and forwarding of dues.

6.03 All future employees as a condition of employment shall become members of the Union after completing a probationary period and shall pay normal monthly union dues commencing at hire date.

6.04 At the same time income Tax T-4 slips are made available, the Employer shall type on the amount of Union dues paid by each employee in the previous year.

ARTICLE 7 - STRIKES/LOCKOUTS

7.01 During the term of this agreement the Corporation agrees not to lock out its employees, and the Union agrees that no cessation or slowdown of production will occur. The Union agrees that it will not involve the Corporation in any dispute between any other group of employees and their employer.

7.02 No employee shall be required to cross any legally authorized picket line while carrying out duties for the Corporation until such time as the Business Rep and/or Corporate representative has been contacted to ensure the safety of the employee.

ARTICLE 8 - EMPLOYEE CATEGORIES

8.01 **Temporary** - Temporary employees are persons hired for a period of up to four (4) calendar months, except where the requirement is to replace an employee on Pregnancy/Parental Leave for a period of six (6) months, in positions which are not likely to become part of the Corporation's continuing organization. Temporary employees shall not accumulate Corporation Service Credit nor shall they have recourse to the grievance procedure, against layoff or discharge.

8.02 **Probationary** - Probationary employees are persons hired on trial to determine their suitability for continuing employment in regular positions. An employee shall be considered probationary for a six-(6) calendar month period. At the end of this probationary period his/her date of hiring will be established as six calendar months prior to the date he/she attains six-(6) calendar months' service. During this period of probation, he/she shall not be considered as having regular status and he/she may be discharged without having recourse to the grievance procedure.

8.03 **Regular** - Regular employees are persons who have satisfactorily served a probationary period and who are normally employed in full-time positions of a continuing nature.

ARTICLE 9 - REDRESS PROCEDURE

9.01 All request and/or complaints shall be taken up with an employee's immediate supervisor.

9.02 It is recognized by the Corporation and the Union that not every such request or complaint is necessarily a grievance (as defined in Clause 10:01 hereof) entitled to be handled under the grievance procedure as hereinafter provided.

ARTICLE 10 - GRIEVANCE PROCEDURES

10.01 Grievance Definition

For the purpose of this agreement a dispute, claim or complaint which involves the interpretation or application of this agreement shall be considered to be a fit matter for grievance and shall be dealt with promptly and as specified below.

10.02 An employee who may request the assistance of his/her steward shall first submit any grievance to his/her superior. In no circumstances may any alleged injustice be considered if it occurred more than ten (10) working days before the date of submission. The supervisor will inform the employee of his/her disposition of the grievance within five (5) working days of the submission.

10.03 Failing a settlement to the employee's satisfaction, the Union may then within five (5) working days of the reply in 10:02, submit a written statement of the grievance. Management will within five (5) working days arrange a meeting to discuss the grievance with the Union committee, which the regular employees may attend. Management will inform the Union committee, in writing, of its disposition of the grievance within five (5) working days of the meeting.

10.04 Failing a settlement to the employee's satisfaction, the Union may within ten (10) working days of the reply in 10:03, notify the Corporation of its intention to submit the grievance to arbitration and at the same time inform the Corporation of the Union nominee to an arbitration board which will then be processed in accordance with the Ontario Labour Relations Act.

10.05 No Board of Arbitration shall have the power to alter or change any of the provisions of this agreement or to substitute any new provision for any existing provision, or to provide a decision which is inconsistent with any term or provision of this agreement. With the agreement of both parties, the Board of Arbitration will be composed of a single arbitrator.

10.06 Each party to this agreement will bear the expenses and fee of its arbitration and the parties will share equally the expenses and fee of the Chairperson.

10.07 Where it is understood that all grievances as defined in Article 10:01 shall be submitted by the employee involved, it is recognized that the union shall have the right to file a grievance on matters within the confines of Article 10:01 which cannot be grieved by any employee.

10.08 Both parties recognize that the purpose of probation is for the employer to properly ascertain that the employee in question is in fact capable of performing the duties for which he was hired. Accordingly, when during the probationary period, the employer determines that such employee cannot perform the duties as hired for, the employer may discharge the employee and such employee shall not have recourse to the grievance and arbitration procedure.

The foregoing does not in any way prevent a probationary employee from lodging a grievance for any other reason as defined by the terms of this Agreement.

ARTICLE 11 - HOURS OF WORK AND OVERTIME

11.01 This section provides the basis for establishing work schedules and for the calculation and payment of overtime, but shall not be read or construed as a guarantee of hours of work per day or week or a guarantee of days of work per week.

11.02 The normal work week of the bargaining unit employees except rotating shift employees shall be forty (40) hours per week consisting of five (5) days of eight (8) hours each between the hours of 7:30 a.m. and 4:00 p.m. from Monday to Friday inclusive. The custodian will work forty (40) hours per week on mutually agreed hours.

11.03 The normal work week of rotating shift employees shall average, on an annual basis, forty-two (42) hours per week from Monday to Sunday inclusive. The normal shift shall consist of eight (8) hours. Work schedules for rotating shift employees shall be maintained three (3) months in advance. It is understood that the two (2) hours beyond the normal forty (40) hour week shall be paid at double time for the rotating shift employees.

11.04 It is acknowledged that from time to time it will be necessary for employees to perform work outside the normal schedules at all hours of the day or night, and management has the right to authorize such work as required.

11.05 Work performed in excess of the regularly scheduled hours of work shall be deemed overtime and paid in accordance with the following schedule:

(a) double time to be paid for overtime work performed after normal scheduled hours.

(b) overtime shall wherever possible, be distributed equitably among those qualified employees working in the same department.

(c) employees required to work overtime, other than in the case of an emergency, will be given at least forty-eight (48) hours prior notice for all scheduled overtime on the weekend or eight (8) hours notice for weekday scheduled overtime.

11.06 When an employee is called in for emergency work outside of his/her normal working hours, he/she shall be provided with a minimum payment of two (2) hours at the appropriate rate or the actual time worked at the appropriate premium rate, whichever is the greater, except when a short call follows within one (1) hour of the completion of a previous call in which case time shall be considered continuous from the start of the previous call. There shall be no minimum payment applicable to scheduled overtime worked as an extension of an employee's normal daily working hours. There shall be no applicable minimum payment applicable to call-outs when an employee commences work one hour prior to starting time.

11.07 An employee may choose, in lieu of payment, to bank earned overtime up to a maximum of forty (40) hours in each calendar year, at the appropriate overtime rate.

(a) The employee shall indicate his/her choice at the time the overtime is assigned.
(b) Banked overtime must be taken in lieu time off, at the employee’s current regular rate of pay, at a time or times mutually agreed upon by the employee and the appropriate supervisor.
(c) Lieu time not used by December 31st of each year will be paid out at the employee’s regular rate as of that date.

11.08 Employees on overtime who have worked a minimum of six continuous hours and the work that they are performing terminates between the hours of 1:30 am and 7:30 am shall be entitled to a minimum of 6 hours rest period. The 6-hour rest period shall be paid for all hours of rest that may fall during the employee’s regular shift based on the time that the work terminated. The employees shall be required to return to work once the 6-hour rest period has been completed or at the Supervisors discretion alternate arrangements can be made with the employee to cover the balance of the normal shift.

ARTICLE 12 - ON-CALL

12.01 All qualified employees will be required to perform on-call duty which will be distributed on an equitable basis among them. Management shall maintain an advance schedule of on-call duty which shall be made available to the staff concerned.

12.02 The payment for on-call duty for qualified employees shall be in accordance with the following:

	Sept. 1, 10	Sept. 1, 11	Sept. 1, 12
Per Week	$190.00	$195.00	$200.00
Per Paid Holiday	$ 45.00	$ 45.00	$ 45.00

On-call shall commence at normal quitting time on Thursday and terminate at normal starting time the following Thursday. In addition, payment for time worked, during on-call hours, shall be as outlined in the overtime provisions of the agreement.

12.03 If an employee scheduled to be on-call is absent due to illness, injury, bereavement, or leave of absence, the qualified employees in the department will be required to cover the on-call duty shift/s. Unless the qualified employees in the department can mutually agree on the coverage, the on-call shift will be covered by the employee with the least seniority.

ARTICLE 13 - VACATIONS

13.01 Vacation pay shall mean the normal basic earnings of the employee immediately prior to the date on which vacation monies become payable. In any event and in the cases of temporary and probationary employees, vacation payments will be made in accordance with the Employment Standards Act.

13.02 Vacations will, as far as it is practical, be granted at the times most desired by the employees. An employee to ensure consideration of his/her request and his/her relative Corporation service credit standing, must notify management of his/her preferred vacation period by April 1st in any given year. However, management reserves the authority to designate vacation periods for all employees in a manner consistent with efficient operation of the Corporation.

13.03 In the event, while on vacation, an employee is admitted to hospital as a result of a serious illness or accident, the employee shall have the right to cease vacation and use his/her sick leave credits. Any vacation so displaced shall be taken at a future date mutually agreed upon between the employee and management. Upon return to work the employee must submit a medical report prepared by a doctor of medicine. The employer shall have the right to have the employee examined by a doctor of medicine as designated by Management.

13.04 A maximum of two (2) consecutive weeks' vacation may be taken by an employee at any one time between June 1st and September 30th. An employee may take, if so entitled, three (3) consecutive weeks if the three (3) weeks are taken between October 1st and March 31st.

13.05 The vacation year shall be January 1st to December 31st. Normal vacations shall not be accumulative and shall not be taken beyond December 31st of the year following an employee's normal vacation year. All vacations not used by December 31st, will be paid to the employee to a maximum of two (2) weeks pay. In order to be eligible for this provision the employee must take a minimum of two (2) weeks vacation.

13.06 Employees shall be credited with their vacation entitlement on January 1st of each year in accordance with the schedule. Progression on the schedule shall occur in the calendar year in which the employee’s anniversary date falls and shall be pro-rated from the employee’s anniversary date of employment to December 31st of that year.

13.07 All full-time employees who have completed their probationary period shall be entitled to take annual vacation with pay, effective January 1st of each calendar year, in accordance with the following schedule:

Continuous Years of Service	Vacation Entitlement
Less than 1	1 day for each month worked to a maximum of 10 days
More than 1	2 weeks (0.83 days per month)
More than 3	3 weeks (1.25 days per month)
More than 9	4 weeks (1.66 days per month)
More than 15	5 weeks (2.08 days per month)
More than 17	5 weeks + 1 day (2.17 days per month)
More than 19	5 weeks + 2 days (2.25 days per month)
More than 21	5 weeks + 3 days (2.33 days per month)
More than 23	5 weeks + 4 days (2.42 days per month)
More than 25	6 weeks (2.50 days per month)

13.08 For employees who are on an unpaid extended leave of absence (exceeding six consecutive months) the holiday time to which they are entitled will be prorated accordingly. The prorating will compare time at work to the whole year and that percentage will be applied to the holiday time the employee is so entitled to.

13.09 For employees who are on either an unpaid leave of absence or a long term disability for any twelve month period the employee will not be entitled to either work boot or clothing allowance.

ARTICLE 14 - PAID HOLIDAYS

14.01 The following paid holidays shall be recognized by the Corporation and shall be observed on such days as may be proclaimed by the Town of Collingwood:

New Year’s Day	Victoria Day	Thanksgiving Day
Family Day	Canada Day	Floater Day
Good Friday	Civic Holiday	Christmas Day
Easter Monday	Labour Day	Boxing Day

and such other holidays which may be proclaimed by the Town of Collingwood.

14.02 The regular employees of the Corporation will be entitled to payment of normal basic wages for such holidays provided they have worked or have been on leave of absence with pay on the normal scheduled days of work which immediately precede and follow such holidays.

14.03 Any employee shall be paid double time for all hours worked on recognized holidays plus holiday pay or a day in lieu as mutually agreed between employee and management.

14.04 If a holiday falls on a regular workday and is within a vacation period, the employee will receive another day in lieu.

14.05 If a holiday falls on an employee's scheduled day off he/she will be granted another day off or pay in lieu thereof, as mutually agreed between management and the employee.

ARTICLE 15 - SICK LEAVE PAYMENT

15.01 The Corporation's sick pay plan for regular employees was created by the Corporation to reduce the financial hardship that bona fide illness can create so far as inability to work and the consequent loss of normal wages are concerned.

15.02 To qualify for payment of sick pay, an employee must:

(a) have an established credit for sick pay;
(b) ensure that his/her illness is reported to management as soon as possible;
(c) be suffering from a bona fide illness which prevents his/her useful employment and is not compensable under the Worker's Compensation Act;
(d) submit written verification of illness signed by a qualified doctor of medicine if requested or if absent for three (3) days or more;
(e) submit to medical examination by a doctor of medicine designated by management upon request;
(f) do everything possible to speed his/her recovery.

15.03 Payments under the Sick Leave Plan will be in accordance to its terms while the employee is disabled until the earlier of:

(a) the employee returns to work; or
(b) the employee retires, either at the normal retirement age or opts to retire early; or
(c) the employee exhausts his/her entitlements under the plan; or
(d) the employee qualifies for long term disability coverage; or
(e) the employee dies; or
(f) the employee resigns.

15.04 **A short term disability** is defined as a period of disability resulting from illness or injury as determined by a qualified doctor of medicine that prevents an employee from attending to his/her regular work and extends for a period of not more than eighteen (18) weeks or ninety (90) days of work. For a period greater than this, the employee will utilize coverage under his/her **Long Term Disability Plan.**

15.05 Coverage of a short-term disability will be in accordance with the following schedule:

	Amount Payable:	
Seniority Service	**100% of Pay**	**75% of Pay**
6 months but less than 1 year	1 week	17 weeks
1 year but less than 2 years	2 weeks	16 weeks
2 years but less than 3 years	3 weeks	15 weeks
3 years but less than 4 years	4 weeks	14 weeks
4 years but less than 5 years	5 weeks	13 weeks
5 years but less than 6 years	7 weeks	11 weeks
6 years but less than 7 years	10 weeks	8 weeks
7 years but less than 8 years	12 weeks	6 weeks
8 years but less than 9 years	15 weeks	3 weeks
9 years or more	18 weeks	0 weeks

Note: All regular employees of the Corporation, as of September 1, 1998, will be granted 100% coverage regardless of his/her actual years of service.

15.06 For the purposes of this Plan, a week of pay for hourly paid employees shall be their normal hours worked per week multiplied by the employee’s standard rate per hour paid on a weekly basis, but shall not include any shift premium, overtime or other increments.

15.07 Payments from the previous rated schedule will be made on the following basis:

(a) a non-occupational accidental injury; or

(b) absence due to illness with the provision that any absence of one (1) or more than one (1) shift, either normal morning or normal afternoon shift, on a scheduled work day, will constitute an occasion;

(1) from the first (1st) day of absence for the first three (3) occasions of absence in a calendar year; and

(2) from the second (2nd) day of the fourth (4th) absence in a calendar year, and

(3) from the third (3rd) day of the fifth (5th) absence in the calendar year, and

(4) from the fourth (4th) day of the sixth (6th) and subsequent absences in a calendar year.

15.08 Payments will be made for a maximum of eighteen (18) weeks during any one continuous period of disability. Successive absences due to the same illness or a related cause will be considered as one continuous period of disability, unless separated by a return to active employment for a period of two (2) months. A disability due to a different cause will be considered a new period, even if the disability occurs within a two (2) month period.

15.09 When an employee can demonstrate to the Employer that he/she can only attend his/her physician as part of a regular treatment during the day, the absence shall not constitute an occasion for the purposes of the plan. Wherever possible, the employee shall try to arrange appointments at the beginning or end of their work day.

15.10 A certificate from a qualified doctor of medicine will be required for each period of absence lasting three (3) or more days or after the third (3rd) occasion of absence in any one (1) year; if requested by the Employer. Employees who have been absent from work due to accident or sickness for a period longer than five (5) working days shall be required to produce a medical certificate stating that the employee is fit to return to work.

ARTICLE 16 - EMPLOYEE BENEFITS PLAN

16.01 (a) The Corporation agrees to pay one hundred percent (100%) of the cost of the current premiums of the Employer Health Tax (EHT) Hospitalization or its equivalent for all regular employees until the age of seventy (70).

(b) The Corporation agrees to pay on behalf of all regular employees until the age of seventy (70), one hundred percent (100%) of the cost of the current premiums of the MEARIE Management Extended Health Care or its equivalent, a dispensing fee cap of $10.00. Out-of-Country and travel assistance benefits are limited to 30 day intervals once the employee reaches the age of sixty five (65).

(c) The Corporation agrees to pay on behalf of all regular employees, until the age of seventy (70), 100% of the current cost of the eyeglass plan as follows:

September 1, 2010 - $350.00/24 months

16.02 The Corporation agrees to pay one hundred per cent (100%) of the current premium cost of the group life insurance policy presently in force on behalf of all regular and retired employees up to the age of sixty-five (65) at which time the employee is transferred to the retiree life division.

16.03 The Corporation agrees to pay on behalf of all regular employees until the age of seventy (70), one hundred per cent (100%) of the cost of current premiums to provide a plan giving the equivalent benefits of the MEARIE Dental Care Plan "E" or its equivalent, current year's Ontario Dental Association fee schedule. Subject to the plans yearly maximum.

16.04 When an employee is on long term disability the Corporation agrees to pay the preceding benefits from Articles 16:01 a, b & c, 16:02 and 16:03, until the age of sixty five (65) years.

16.05 The Corporation agrees to provide coverage of the existing Dental, Health and Eyeglass Plans, if an employee retires prior to the age of 65, with a combined age (minimum fifty-five (55) years) and service (minimum of twenty-five (25) years) credit, to a total of at least 80 years. This will continue until the former employee reaches the age of 65 years.

16.06 It is recognized that the employee benefits flowing from this document satisfy the requirements of E.I. regulations covering rebates to employees. The employees waive the right to the rebate on account of the Employer providing the aforementioned benefit.

It is understood that all employees while on WSIB shall receive a top up allowance to equalize 100% of their current rate of pay.

ARTICLE 17 - WORKERS' COMPENSATION

17.10 When an employee through his/her paid employment by the Corporation, suffers an illness or injury which is compensable under the Workers' Compensation Act, The employee will receive payment in accordance with the Act for a period of twenty-four (24) months. The Corporation shall continue to pay of a period not to exceed twenty-four (24) months, the benefit premiums under Article 16.

ARTICLE 18 - JOB POSTING AND SELECTION

18.01 When a vacancy occurs, or a new regular position is created within the bargaining unit, the Corporation shall post a notice of the vacancy for a minimum of five (5) working days. All qualified employees may make written application for the vacant position.

18.02 The selection of applicants for vacancies or promotion shall be made only from those applicants who are judged by the Corporation to be qualified to do the work and will be based on:

(a) merit
(b) ability
(c) accumulated Corporation service

In the event that in the opinion of the Corporation, merit and ability are equal, the Corporation service credit shall govern.

ARTICLE 19 - LAYOFF AND RECALL

19.01 In the event of a lay-off, management agrees that employees be laid off in the reverse order of their Corporation service credit provided that management can retain a work force qualified to perform the work available. Employees shall be recalled in the order of Corporation service credit provided they are qualified, capable and have the ability to do the work available.

19.02 During the term of this Collective Agreement, no regular full-time Employee will be laid off as a result of outsourced labour services.

ARTICLE 20 - MEALS

20.01 A suitable meal will be provided to an employee who has worked continuously for two (2) hours beyond a regular scheduled work day and every four (4) hours thereafter as long as the employee continues to work. Effective September 1, 2010, there will be a thirteen dollar ($13.00); September 1, 2011, fourteen dollar ($14.00); September 1, 2012, fifteen dollar ($15.00), maximum allowed for a meal as long as a request for allowance be submitted with a receipt and only that total will be paid.

For work outside the boundaries of the Town of Collingwood the following shall apply:

If an employee arrives at the COLLUS Power Headquarters in Collingwood and is given instructions that he or she will be working outside the boundaries of the Town of Collingwood (i.e. Stayner, Creemore or Thornbury) over the normal lunch period the Company agrees to pay a meal allowance as outlined above.

However, if an employee is told in advance (minimum day before) that he or she will be working outside the boundaries of the Town of Collingwood (i.e. Stayner, Creemore or Thornbury) over the normal lunch period, and then the meal will be the responsibility of the employee.

20.02 Meal period for such meals shall be a one-half (1/2)-hour duration and such time shall not be paid.

ARTICLE 21 - TOOLS AND EQUIPMENT

21.01 The Corporation shall supply all tools necessary to carry out the work involved in maintaining service. An employee must return worn-out or broken articles in order to receive replacement. An employee may be required to pay for lost tools.

ARTICLE 22 - CLOTHING

22.01 The Corporation shall supply the following articles to the employees who in the Corporation's opinion require such items on a need be basis. The initial outlay is as follows;

- rain gear, safety glasses, rubber boots, leather gloves and vests
- three (3) orange fire retardant and reflective Tee-shirts
- three (3) orange fire retardant and reflective long sleeve shirts

- three (3) orange fire retardant and reflective sweatshirts
- three (3) pants (blue fire retardant and reflective)
- one (1) orange fire retardant and reflective bomber jacket or winter parka
- two (2) orange fire retardant and reflective summer coveralls
- two (2) orange fire retardant and reflective winter coveralls

Employees in the Filtration Plant, Customer Service, Metering, Stores, and the Custodian will be issued the above listed clothing in blue fire retardant and reflective. Worn out or damaged articles must be turned back in to receive new at the discretion of the Supervisor.

22.01 (a) All employees that are issued fire retardant uniforms must wear issued uniforms during all work hours.

22.02 Regular employees required by the Construction Safety Branch of the Ministry of Labour to wear safety boots on the job will be reimbursed the following yearly amounts after September 1st of each year upon surrender of receipts for the purchase of the safety boots.

2010	-	$250.00
2011	-	$250.00
2012	-	$250.00

ARTICLE 23 - COMMUNICATIONS SYSTEM

23.01 Employees required for on call will be given suitable wireless communications at the Corporation's expense.

ARTICLE 24 - LEAVE OF ABSENCE

24.01 Under certain conditions management may authorize the absence of an employee from work. Normally, no payment of wages will be made for the period involved.

24.02 Leaves of absence require the written permission of management and applications for leave of absence must be submitted in writing one (1) calendar month in advance to ensure consideration.

24.03 Unauthorized absence from work will constitute voluntary termination of employment except in cases where management considers the circumstances emerging are beyond the employee's control and the employee has notified management of the circumstances as soon as possible.

24.04 All unused vacation and lieu time must be used before a request for a leave of absence is considered.

24.05 An employee who is elected or appointed as a delegate to a union convention or conference will be granted leave of absence for a period up to eight (8) weeks.

The employee will not receive pay while absent, and the Corporation will not be expected to pay his relief any more money than the delegate would have earned during the leave of absence period had he been on duty. Such leave of absence will be granted only once during the calendar year.

The seniority of such employee shall continue and accumulate during such leave of absence. The Union shall reimburse the Corporation for the employee's benefit costs during the leave.

Any leave of absence granted will be in writing and no such leave will affect any employee's seniority rights when used for the purpose granted. If an employee works elsewhere while on leave of absence he will lose all seniority unless he has written permission from the Corporation to do such work. An appointment to a paid committee of the Union will not be construed as working while on leave of absence.

ARTICLE 25 - BEREAVEMENT LEAVE

25.01 In the event of the death of a member of the immediate family (Husband, Wife, Son or Daughter, and Parents) of a regular employee, the employee may be granted a leave of absence with pay up to four (4) working days in order that he/she may arrange for and attend the funeral. Only that portion of the said four (4) days that would otherwise have been regular time worked will be paid. An entitlement of three (3) working days shall be given to include, parent-in-law, brother, sister, grandparent, grandparent-in-law, brother-in-law and sister-in-law.

25.02 In the event of the death of a relative other than a member of the immediate family, the employee may be granted one (1) day's leave of absence with pay in order that he may attend the funeral.

ARTICLE 26 - WORK AND SAFETY RULES

26.01 The Corporation and union agree to use the approved Electrical Utilities Safety Association (EUSA) rulebook as the basis for establishing work and safety rules. The two parties also agree to maintain an environment that is within the limits of the Occupational Health and Safety Act.

26.02 All employees shall realize that Safety and the maintenance of a safe and healthy work environment is mandated by the Occupational Health and Safety Act and is considered by the Corporation as a **"condition of employment**".

ARTICLE 27 - REPRESENTATION

27.01 The union shall provide the Corporation with a list of union officials to be revised from time to time as changes occur. The Corporation shall provide the union with a list of supervisors to whom grievances and other relevant matters may be submitted.

27.02 The Corporation will recognize a committee of two (2) employees plus one (1) union representative in negotiations and the second step of the grievance procedure. The Corporation will deal with the said committee on all matters which are properly the subject of negotiation of an agreement, an amendment thereto, a renewal thereof, in a grievance therein. The union recognizes that union officials have regular duties to perform for the Corporation and subject to this recognition the Corporation agrees to maintain standard rate of pay for time spent by union officials on grievance matters during normal working hours as defined in Articles 10:02 and 10:03 of this agreement but not including arbitration.

ARTICLE 28 - ADVERSE WEATHER

28.01 The manager or his/her delegate concerned shall be the sole judge of what constitutes adverse weather conditions. The manager or his/her delegate shall be cognizant of the work that should not be performed in certain weather conditions.

28.02 During such period management will endeavour to provide alternate work.

28.03 An employee who does not show up for work when the Corporation is open, must use vacation time, or make up the time for the duration of the missed working hours.

ARTICLE 29 - BULLETIN BOARDS

29.01 The Corporation will provide bulletin board space in an area designated by the Corporation for the purpose of posting notices. All notices before they are posted, must be approved by the manager or his/her delegate.

ARTICLE 30 - DISTRIBUTION OF AGREEMENT

30.01 The responsibility for printing and distributing this agreement shall rest with the Corporation.

30.02 The Corporation agrees to ensure that the union receives sufficient copies of the agreement for distribution to the employees of this bargaining unit.

ARTICLE 31 - WAGES

31.01 Employees will receive rates of pay in accordance with Schedule "A". The classifications and rates are listed therein for purposes of payment of wages only.

31.02 WAGE INCREASE – As per Schedule “A”

ARTICLE 32 - RELIEVING IN HIGHER GRADE

32.01 An employee temporarily assigned to a position with a higher hourly wage for a period of four (4) hours or more will be paid at 110% of their hourly rate for the entire period of relief. Relieving in a higher grade shall be made only from those applicants who are judged by Management to be qualified to do the work and will be based on:

(a) merit

(b) ability
(c) accumulated service credit

In the event that in the opinion of Management, merit and ability are equal, the accumulated service credit shall govern.

ARTICLE 33 - DURATION

33.01 This agreement shall remain in affect for a period of three (3) years from September 1st, 2010 to August 31st, 2013, and shall continue in force from year to year thereafter, unless not more than three (3) months and not less than thirty (30) days before the date of its termination, the union notifies management in writing of its' desire to amend this agreement.

ARTICLE 34 - JURY DUTY

34.01 The Corporation will pay normal straight time pay to those employees who must participate as a juror or subpoenaed witness in a court case within the province of Ontario. This is provided if the employee signs over to the Corporation, any remuneration received for such duties, excluding: travelling, meals, or other expenses.

ARTICLE 35 - TRAINING

35.01 The Union and Corporation/Management both recognize the importance of Training therefore it is the responsibility of both parties to maintain a highly trained working staff.

ARTICLE 36 - RESIDENCY

36.01 As a condition of their continuing employment, all new employees who shall be on-call, must live within twenty-five (25) minutes (automobile travel time under favourable driving conditions) from the COLLUS Service Centre, 43 Stewart Road, Collingwood. New employees must establish such residency not later than three (3) months after completion of their probationary period.

ARTICLE 37 - PARTNERSHIP AGREEMENT

37.01 It is the intent of the Parties in entering into this Agreement to find a positive way of achieving harmonious and mutually supportive relationships among the Companies, the Employees and the Union, which will keep the Utility in a strong, competitive market position.

The Parties recognize that in addition to competitive wages, safe working conditions, and fair treatment, it is important that we present our best image to the public at all times. The employees, the Company and the Union must treat each other with respect and to show our Citizens and our Shareholder the Team Spirit and positive attitudes that will be an essential factor in the success of the company.

Therefore, the Parties are entering into this Agreement as partners, rather than adversaries.

ARTICLE 38 – DRIVERS LICENCE

38.01 The Corporation agrees to pay for the cost of the licence that any employee needs in the performance of his/her duties other than standard class "G" driver's licences.

SIGNED:

for the Union: for the Corporation:

____________________ ____________________

____________________ ____________________

____________________ ____________________

Dated at, Collingwood ______________ Ontario,

this _______ day of ____________________, 2011

SCHEDULE "A"

Category	Sept. 1, 2010	Sept. 1, 2011	Sept.1, 2012
Hydro Department			
Journey Linesperson Lead-Hand (110%)	$37.31	$38.43	$39.58
Journey Linesperson (100%)	$33.92	$34.93	$35.98
Linesperson - Fourth Year	$32.36	$33.33	$34.33
- Third Year	$29.22	$30.10	$31.00
- Second Year	$26.11	$26.89	$27.70
- First Year	$22.97	$23.66	$24.37
Journeyperson Technician Lead-Hand (110%)	$37.31	$38.43	$39.58
Journeyperson Meter Technician	$33.92	$34.93	$35.98
Meter Technician - Third Year	$32.36	$33.33	$34.33
- Second Year	$29.22	$30.10	$31.00
- First Year	$26.11	$26.89	$27.70
Inspector/Locator	$30.97	$31.89	$32.85

[redacted]

[redacted]

4-SEC-11
[Ex.4/1/4/p.4]
Please explain how 28.5 % increase in the Community Relations budget can be "primarily due to inflationary based salary increases".

Response

The correct reference appears to be Exhibit 4, Tab 1, Schedule 1, Page 4 of 10.

The explanation for the increase in community relations on page 4 states, "The total growth in costs in the Community Relations area has been $31K or 28.5%. The program increases in the Community Relations area related primarily to inflationary based salary increases."

While 28.5% sounds like a large difference, the actual dollar value change is only $31k. A history of community relations expenditures is provided below, but it does have some real variation from year-to-year. Upon further investigation the notes on the table were added to explain.

	Actual Year-to-Date	Forecast					OEB Approved
	30-Jun-13	*December 2013*	*December 2012*	*December 2011*	*December 2010*	*December 2009*	2009
5415-0000-00 Energy Conservation				5,117	8,041		
5425-0000-00 Misc Cust Ser&Inform Expenses	70,805	138,000	133,479	144,911	158,530	103,213	107,389
Total Community Relations	70,805	138,000	133,479	150,028	166,572	103,213	107,389
Variance to 2009 OEB approved		30,611.00					
% variance to OEB approved		28.50%					

Notes:
1) Some of the increase will be related to annual wage increases.
2) There appears to be fluctuation in earlier years between 5305 Billing Supervision, 5315 Customer Billing, & 5320 Collecting.
3) Additional table prepared to compare accounts listed in point 2 above with 5425 Misc Customer Service & Information.

The following table provides more useful comparison, with these categories combined. Some deviation in wage postings is apparent. In 2009, the billing supervisor went on a sudden disability leave and was never able to return. The billing supervision allocation appears to have never been adjusted for employees and contract workers filling in. This corrects in 2011. An outside service was required in 2010 to assist with the fill-in for the disabled employee and the cost for the support was significant.

If you look at these categories as a whole, it is apparent that the 2013 revenue requirement request is actually $27,482 less than 2009 OEB approved. It is also apparent that the June 30th results are tracking almost exactly to the December 2013 forecast.

Looking at the Miscellaneous Customer Service & Information expense account on its own makes meaningful analysis difficult. But this analysis does give some more meaningful insight.

	Year-to-Date June 30, 2013	Forecast December 2013	December 2012	December 2011	December 2010	December 2009	OEB Approved 2009
5305-0000-00 Billing Supervision	36,950	84,000	60,035	46,131		13,420	49,000
5315-0000-00 Customer Billing	181,743	372,000	370,657	386,889	491,705	492,772	489,093
5320-0000-00 Collecting	52,210	93,000	100,646	86,670	104,753	59,618	69,000
5425-0000-00 Misc Cust Ser&Inform Expenses	70,805	138,000	133,479	144,911	158,530	103,213	107,389
	341,709	687,000	664,818	664,601	754,988	669,024	714,482
June 30th * 2 - Full year estimate to compare		683,418					
Variance to budget		3,582					

4-Energy Probe-26

Ref: Exhibit 4, Tab 1, Schedule 2

a) Have any of synergies and cost reductions noted as a result of the PowerStream acquisition of 50% of the shares of Collingwood Utility Services Corp. been reflected in the 2013 revenue requirement? If not, why not? If yes, please provide an estimate of the impact.

b) Does Collus PowerStream have an estimate of the savings in years beyond 2013? If yes, please provide the details.

c) What costs have been incurred in 2012 and/or in 2013 as a result of the acquisition by PowerStream of 50% of the shares of Collingwood Utility Services Corp. as they relate to the regulated distributor (such as the name change, changes to letterhead, changes to bills, etc.)?

d) If any of the costs identified in part (b) above are included in the Collus PowerStream OM&A in 2012 or 2013, please quantify the amounts included in each year and provide a breakdown of the expenses.

Response

a) No synergies or cost reductions as a result of the PowerStream acquisition have been reflected in the 2013 revenue requirement. Since the PowerStream deal did not close until March 1, 2013, it would not be reasonable that 2013 would include any expectations of efficiency gains. It is too premature to determine what those savings will be and we cannot provide an estimate of the impact at this time.

b) No, Collus PowerStream does not currently have an estimate of the savings in years beyond 2013.

Initially we will target goals in areas which are easily achievable and can be undertaken quickly and with little resistance. We will go after the low hanging fruit first because those initiatives, by definition, are the ones that are easiest to do and will have the biggest impact on efficiency and productivity.

Some previously entered agreements and contracts with other outside service providers have legal termination restrictions that will delay our ability to utilize PowerStream's services for three to five years in some cases. Such areas will take a longer amount of time to resolve and plan out.

c) There has been very little spent on the rebranding of Collus Power to Collus PowerStream. There were no additional costs for things such as envelopes or letterhead since we used up all of the existing stock we had before using any new. The bill was simply changing the logo in the computer and there was no additional cost. We changed the logo on less than a dozen vehicles and one sign on our front entrance.

Vehicle Logo Changes and Front Entrance Sign $3,153

d) 2012 - Vehicle Logo Changes and Front Entrance Sign $3,153
2013 - None

4-SEC-12
[Ex.4/1/2/p/2]
Please quantify and detail the anticipated savings in the Test Year as a result of the 50% acquisition by PowerStream Inc.

Response

As noted in our application, the potential savings are not quantifiable at this time. We can however note that staff has been diligently working on identifying areas in which our new relationship can provide future mitigation of upward pressure on distribution rates and in areas in which we can provide better customer service. Areas that have been investigated are: procurement of large vehicles, utilization of PowerStream's Control Centre, coordination of conservation and demand management programs, regulatory issues, human resources policy and practises, governance policies, smart grid, to note just a few.

4-SEC-13
[Ex.4/2/1/p.1-2]
Please provide a copy of the results of the 12th Annual Electricity Utility Customer Survey and the 2013 UtilityPulse survey.

Response

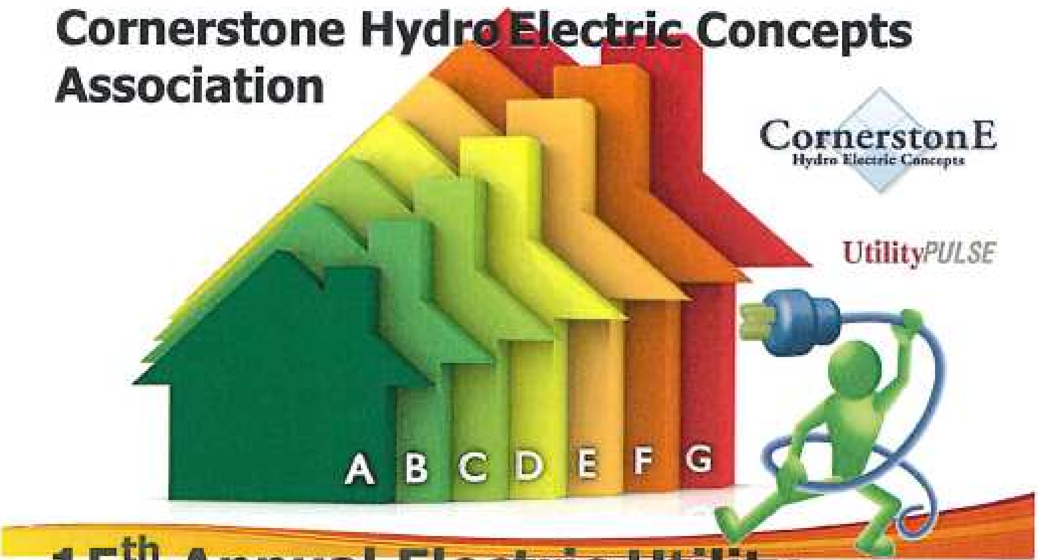
A copy of the 2013 Utility Pulse Survey is attached.

We do not have a copy of the "12th Annual Electricity Utility Customer Survey" and are not familiar with this survey.

Cornerstone Hydro Electric Concepts Association

CornerstonE
Hydro Electric Concepts

UtilityPULSE



15th Annual Electric Utility Customer Satisfaction Survey

The purpose of this report is to profile the connection between CHEC Group and its customers.

The primary objective of the Electric Utility Customer Satisfaction Survey is to provide information that will support discussions about improving customer care at every level in your utility.

The UtilityPULSE Report Card® and survey analysis contained in this report do not merely capture state of mind or perceptions about your customers' needs and wants - the information contained in this survey provides actionable and measurable feedback from your customers.

All comments and questions should be addressed to:

Sid Ridgley, UtilityPULSE division, Simul Corporation

Toll free: 1-888-291-7892 or Local: 905-895-7900

Email: sidridgley@utilitypulse.com or sridgley@simulcorp.com

Executive summary

"Putting the Consumer First" was part of the title of the *Report of the Ontario Distribution Sector Review Panel*. Its findings and recommendations add an additional level of challenges and opportunities. While the Report challenges the structural nature and efficiency of LDCs in Ontario, the "customer" remains focused on their own needs and expectations. The customer is primarily concerned about their overall costs for their electricity rather than the costs of the individual components of producing, transmitting, distributing and regulating electricity.

For the past 15 years, the only constant Ontario LDCs and their customers have faced is constant change. With topics such as SMART Meters, SMART Grid, green energy, infrastructure renewal, coupled with the recommendations from the Ontario Distribution Sector Review Panel, it is easy to predict that change will continue – for many years to come. One of the challenges for utilities today is

to determine how to educate, empower and engage their residential and small business customers. The goal for utilities is to cut through the fog of fear, misinformation and confusion that exists amongst its customers, regarding a myriad of subjects, while retaining a very high level of trust, respect and credibility.

Trust and credibility are the foundational building blocks for ensuring that customers have both their rational and emotional requirements

fulfilled. The attributes which help an LDC to be seen as trusted and highly credible are: knowledge, integrity, involvement and trust. On demonstrating Credibility and Trust, CHEC Group has done well. Overall, CHEC Group 87% [Ontario 82%; National 82%].

Customers, as human beings, are both rational and emotional. The rational side of the customer holds the LDC accountable for doing its job (as contracted), thereby fulfilling the customer's basic needs. The emotional side of the customer is about fulfilling expectations. Meeting rational needs – at best – gets the customer to a neutral state and at worst creates dissatisfaction. Emotional needs, when met, assuming base level rational needs are met, can move a customer from neutral to higher levels of satisfaction.

The old adage, "You cannot command respect, you have to earn respect" is a lesson that aptly describes the loyalty effect with customers. Many people mistakenly think doing a good job will lead to loyalty; that a satisfied customer equals a loyal customer. Customers have expectations of their electric utility that go far beyond "keeping the lights on", "billing me properly", and "restoring power quickly".

- **Satisfaction** happens when utility core services meet or exceed customer's needs, wants, or expectations.
- **Loyalty** occurs when a customer makes an emotional connection with their electric utility on a diverse range of expectations beyond core services.

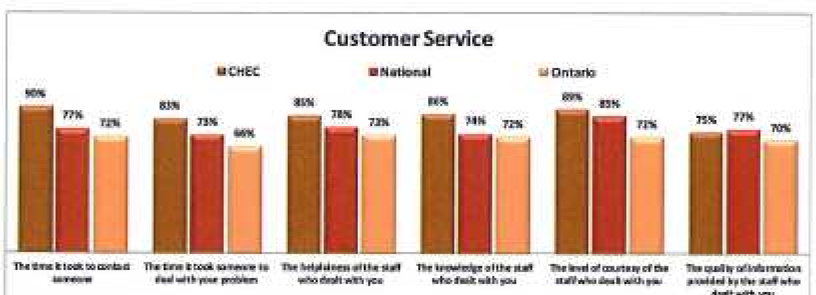
Satisfaction alone does not make a customer loyal; a willingness to commit and advocate for a company along with satisfaction identifies the three basic customer attitudes which underpin loyalty profiles. While satisfaction is an important component of loyalty, the loyalty definition needs to incorporate more attitudinal and emotive components.

CHEC SATISFACTION SCORES – Electricity customers' satisfaction

Top 2 Boxes: 'very + fairly satisfied'	2013	2012	2011	2010
PRE: Initial Satisfaction Scores	92%	-	-	-
POST: End of Interview	94%	-	-	-

Base: total respondents / (-) not a participant of the survey year

Customers have needs and expectations AND they will have problems. How those problems are dealt with are "proof points" which will validate or invalidate their perceptions. Customer problems are far more diverse than they have ever been, thereby, causing customer service to change in response to those problems and needs. Given the increase in fragmentation of customer type and customer problems, the need for building a customer-centric culture in line with customers' needs, preferences and expectations is important when customer satisfaction is important to the organization.



Base: total respondents who contacted the utility

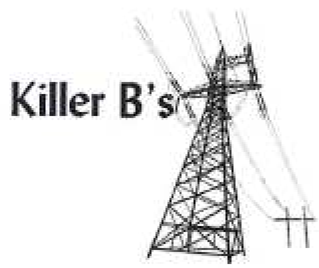
The Killer B's (Blackouts and Bills)

It is inevitable that there will be blackouts/power outages – the key is how a utility anticipates outages and deals with them. It should also be noted that there is a disconnect between what a utility might call a "billing problem" and what a customer defines as a "billing problem". Though both viewpoints are valid, employees need to be trained to answer those that cause the most concern with customers.

Percentage of Respondents indicating that they had a Blackout or Outage problem in the last 12 months

	CHEC	National	Ontario
2013	36%	41%	35%
2012	-	44%	46%
2011	-	43%	43%
2010	-	45%	41%

Base: total respondents / (-) not a participant of the survey year



Percentage of Respondents indicating that they had a Billing problem in the last 12 months

	CHEC	National	Ontario
2013	10%	8%	10%
2012	-	12%	13%
2011	-	10%	16%
2010	-	10%	12%

Base: total respondents / (-) not a participant of the survey year

What do customers think about electricity costs?

There is a correlation between ability to pay and satisfaction with higher earners reporting the highest levels of initial satisfaction with their utility. It is also true that emotional connectivity, i.e. loyalty, also plays a role about what customers think about costs. Out of all the Ontario survey respondents this year, only 17% of Secure customers vs 43% of At Risk customers report that they sometimes or often worry about paying their electricity bill.

Is paying for electricity a worry or major problem ...

	CHEC	National	Ontario
Not really a worry	67%	70%	66%
Sometimes I worry	24%	18%	21%
Often it is a major problem	4%	8%	11%
Depends	3%	2%	1%

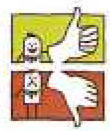
Base: total respondents

Customer Experience Performance rating (CEPr)

New for 2013 is the Customer Experience Performance rating (CEPr). Every touch point with customers on the phone, website or in-person influences what customers think and feel about the organization.

Customer Experience Performance rating (CEPr)			
	CHEC	National	Ontario
CEPr: all respondents	87%	83%	83%
CEPr: respondents *who have* contacted their utility	83%	79%	77%
CEPr: respondents *who have not* contacted their utility	88%	84%	85%

Base: total respondents



The key is handling every individual element of an interaction with a customer so that he/she feels good at the end of the whole interaction and the utility achieves its business objectives.

While an excellent transaction today creates a positive experience today, the perception created is that future transactions will be excellent too, which is how you want your customers to feel. Of course, a negative transaction creates the perception that future transactions will be negative.

Customer Engagement Index (CEI)

UtilityPULSE has been researching this topic for the past 2 years and we have found that there are 4 basic types of definitions associated with the term called "customer engagement". Here are the basic types:

1- Participation in programs or service offerings
2- Pro-active "reach-out" to customers
3- Customer loyalty
4- How customers think, feel and act towards the organization that serves them.

Drawing from our 25+ years of experience working with enterprises in both the private and public domains, we believe that basic types 1 & 2 are too simplistic and tend to be an efficiency measurement. Whereas types 3 & 4 are more valuable to the organization especially when a key corporate goal is to create an operationally effective place to do business with – essentially an effectiveness and outcomes oriented measurement.

Engagement is how customers think, feel and act towards the organization. As such, ensuring that customers respond in a positive way requires that they are rationally satisfied with the services provided AND emotionally connected to your LDC and its brand. The more frequently and consistently an organization's products and services can connect with a customer, especially on an emotional level, the stronger and deeper the customer becomes engaged with the organization. The six dimensions of an outcome based definition of customer engagement are: empowered, valued, connected, inspired, future oriented and performance oriented.

Utility Customer Engagement Index (CEI)			
	CHEC	National	Ontario
CEI	86%	81%	81%

Base: total respondents

UtilityPULSE Report Card©

The purpose of the UtilityPULSE Report Card is to provide your utility with a snapshot of performance – it represents the sum total of respondents' ratings on 6 categories of attributes that research has shown are important to customers for influencing satisfaction and affinity levels with their utility.

CHEC's UtilityPULSE Report Card©

Performance

	CATEGORY	CHEC	National	Ontario
1	**Customer Care**	A	B+	B+
	Price and Value	B+	B	B
	Customer Service	A	B+	A
2	**Company Image**	A	A	A
	Company Leadership	A	A	A
	Corporate Stewardship	A	A	A
3	**Management Operations**	A	A	A
	Operational Effectiveness	A	A	A
	Power Quality and Reliability	A+	A	A
	OVERALL	A	A	A

Base: total respondents

Corporate Image

Organizations today, are always under scrutiny and have to consider the reality AND perception of their image. Increasingly, organizations have realized that the management of a strong positive image with various stakeholders can be beneficial.

Attributes strongly linked to a hydro utility's image

	CHEC	National	Ontario
Is a respected company in the community	89%	83%	84%
Maintains high standards of business ethics	88%	81%	81%
A leader in promoting energy conservation	85%	80%	80%
Keeps its promises to customers and the community	88%	81%	82%
Beyond providing jobs and paying taxes, is socially responsible	86%	79%	79%
Is a trusted and trustworthy company	89%	83%	83%
Adapts well to changes in customer expectations	80%	74%	73%
Is 'easy to do business with'	88%	82%	81%
Overall the utility provides excellent quality services	87%	85%	83%
Operates a cost effective hydro-electric system	79%	72%	68%

Base: total respondents with an opinion

Supplemental Insights

Recognizing that customers' interests and needs continue to shift, we have provided data and SMART insights, on a number of subjects such as e-care, e-billing, conservation and more.

SMART Meters & SMART Grid

Do economic incentives have an impact on resource consumption patterns? *77% agree strongly or somewhat that Time-of-Use billing has changed the way in which they consume electricity on a day-to-day basis. [Base: Ontario LDC respondents]*

SMART metering is also a key element of SMART grid technology. This year's survey probed around the concept of SMART grid, its importance and support towards working with neighbouring utilities. It is clear that the need for education is immense. It is also clear that the majority of respondents are very + somewhat supportive of the utility working with neighbouring utilities on SMART grid initiatives.

Level of knowledge about the SMART Grid

	Ontario LDCs
I have a fairly good understanding of what it is and how it might benefit homes and businesses	7%
I have a basic understanding of what it is and how it might work	17%
I've heard of the term, but don't know much about it	33%
I have not heard of the term	42%
Don't know	1%

Base: An aggregate of respondents from 2013 participating LDCs

Importance of pursuing implementation of the SMART Grid

	Ontario LDCs
Very important	23%
Somewhat important	30%
Neither important or unimportant	9%
Somewhat unimportant	5%
Unimportant	10%
Don't know	23%

Base: An aggregate of respondents from 2013 participating LDCs

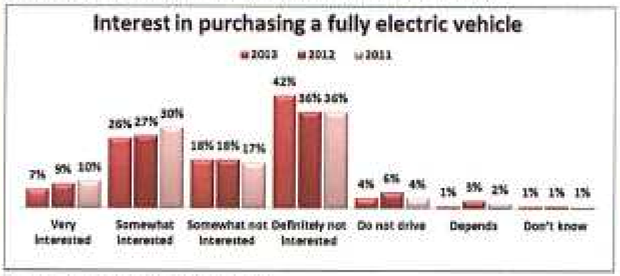
Support towards working with neighbouring utilities on SMART Grid initiatives

	Ontario LDCs
Very supportive	38%
Somewhat supportive	37%
Neither supportive or unsupportive	4%
Somewhat unsupportive	2%
Unsupportive	6%
Don't know	12%

Base: An aggregate of respondents from 2013 participating LDCs

Purchasing an Electric Vehicle

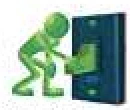
Looking at age demographics, 22% of older respondents (55+) versus 47% of respondents aged 35-54 and 43% aged 18-34 are in favor of EVs replacing conventional cars.



Base: total respondents in the Ontario Benchmark survey

Energy Conservation & Efficiency

Improving energy efficiency does not mean that customers have to give up or forgo activities to save energy. Rather, new technologies and more effective behaviour will actually allow customers to do more, improving their living conditions rather than reducing their comfort. Energy efficiency can be broken down into two areas: *better use of energy through improved energy-efficient technologies;* and



energy saving through changes in customer awareness and behaviour. During the survey interview process, we asked *"what are the 1 or 2 barriers for creating higher levels of energy efficiency?"* 21% identified "costs involved in making equipment/appliance changes", and 12% identified "lack of knowledge or lack of information". Respondents were asked: *"What will you be doing to conserve energy?"*

Efforts to conserve energy

Ontario LDCs	Yes	No	Already Done	Don't Know
Install energy-efficient light bulbs or lighting equipment	20%	10%	69%	1%
Install timers on lights or equipment	15%	49%	35%	2%
Shift use of electricity to lower cost periods	21%	19%	57%	3%
Install window blinds or awnings	15%	26%	58%	1%
Install a programmable thermostat	15%	20%	63%	2%
Have an energy expert conduct an energy audit	9%	70%	18%	3%
Removing old refrigerator or freezer for free	14%	45%	37%	4%
Join the peaksaverPLUS™ program	18%	48%	21%	13%
Replacing furnace with a high efficiency model	13%	36%	48%	3%
Replacing air-conditioner with a high efficiency model	16%	39%	41%	4%
Use a coupon to purchase qualified energy saving products	33%	42%	21%	4%

Base: An aggregate of respondents from 2013 participating LDCs

E-care and E-billing

For any service provider including electric utilities, using the Internet for online customer care and electronic billing involves a number of interrelated requirements, including a customer's ability to: sign up for and change their services using the internet, find answers to their questions online about their accounts, learn about products, services and topics, i.e., green energy, electricity pricing, etc. It is about giving control to the customer.

83% of CHEC Group respondents have access to the internet and 14% have accessed their utility's website in the last six months.

Consumers will eventually adopt electronic billing and online customer care as many industries/companies begin providing consumer bills online, and critical mass is reached.

Using the Internet for billing

	Ontario LDCs	CHEC
I am already receiving my hydro bill electronically	10%	4%
I use on-line banking and will definitely be requesting that my bill be sent electronically	11%	11%
I use on-line banking but prefer to have paper statements	30%	35%
I prefer to have the paper copy of my bills	23%	28%
I don't use on-line banking	17%	22%

Base: An aggregate of respondents from 2013 participating LDCs / 90% of total respondents from the local utility

Social Media

Social media is evolving at an incredible pace. Importantly, it seems to represent a shift in how people discover, read and share news, information and content. Respondents of this year's survey were asked *"how likely they would use social media such as twitter®, facebook® (and others) as a resource for energy efficiency tips or to help manage your electricity use"...*

Likelihood of using Social Media

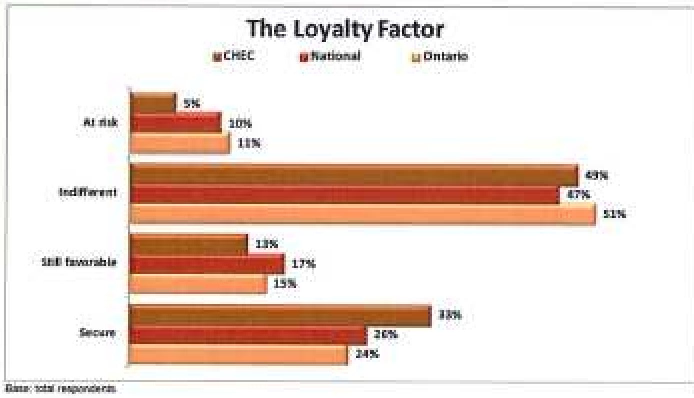
	CHEC	Ontario LDCs	Ontario LDCs Age Group:18-34	Ontario LDCs Age Group: 55+
Very likely	4%	6%	10%	3%
Somewhat likely	7%	11%	17%	6%
Not likely	22%	20%	24%	17%
Not likely at all	64%	61%	48%	68%
Don't have social media account	2%	2%	0%	4%
Don't know	0%	1%	0%	1%

Base: An aggregate of respondents from 2013 participating LDCs / 90% of total respondents from the local utility

Customer Affinity

Private industry often equates customer loyalty with basic customer retention. If a customer continues to do business with a company, that customer is, by definition, considered to be loyal. If this definition were applied to many companies in the utility industry, all customers would automatically be considered loyal. As such, measuring customer loyalty would appear to be unnecessary.

Natural monopolies (like LDCs) are not really different in what they should measure except that trying to determine which customers are "loyal" or "at risk" is not about a customer's future behaviour but more about their "attitudinal" loyalty (are they advocates?).



Base: total respondents

Customer Loyalty Groups				
	Secure	Favorable	Indifferent	At Risk
		CHEC		
2013	33%	13%	49%	5%
2012	-	-	-	-
2011	-	-	-	-
2010	-	-	-	-

Base: total respondents / (-) not a participant of the survey year

Electricity customers' loyalty – is a company that you would like to continue to do business with				
CHEC	2013	2012	2011	2010
Top 2 boxes: 'Definitely + Probably' would continue	85%	-	-	-

Base: total respondents / (-) not a participant of the survey year

Electricity customers' loyalty – is a company that you would recommend to a friend or colleague				
CHEC	2013	2012	2011	2010
Top 2 boxes: 'Definitely + Probably' would recommend	78%	-	-	-

Base: total respondents / (-) not a participant of the survey year

Every LDC has a brand and a brand image, while that image can be affected by events in the industry beyond the control of the LDC, the reality is there is a cost benefit to improving the customer experience, generating higher levels of customer engagement and growing the numbers of Favourable and Secure customers. Providing consistent reliable energy while being seen as 'easy to do business with', along with providing information and support for customers to use electricity more efficiently are core components of a successful relationship with customers.

Marketing – Communications

	CHEC	National	Ontario
Topics that require more pro-active communication			
Cost of electricity is reasonable when compared to other utilities	69%	66%	61%
Works with customers to keep their energy costs affordable	73%	66%	65%
Adapts well to changes in customer expectations	80%	74%	73%
Operates a cost effective hydro-electric system	79%	72%	58%
Provides good value for money	76%	71%	58%
Topics that your utility scores very well on			
Is a trusted and trustworthy company	89%	83%	83%
Respected company in the community	89%	83%	84%
Accurate billing	88%	85%	86%
Overall the utility provides excellent quality services	87%	85%	83%
Provides consistent, reliable energy	91%	90%	90%

Base: total respondents with an opinion

UtilityPULSE is the only enterprise with multiple year customer trend data that appears on the List of Presenters and Submitters in the *Report of the Ontario Distribution Sector Review Panel*. With 14 years of data (15 now that the 2013 survey has been completed), we know that LDCs in Ontario have made excellent progress in the way(s) in which customers are cared for and served – despite the massive amounts of change that have taken place during that same timeframe.

We've often been asked: "What does it take to be seen as having great customer service?" Our answer continues to be "have genuine empathy for customers". If you and your fellow employees don't have it, then your organization will not achieve the highest levels of customer engagement and affinity as may be possible. This requires CHEC Group to ensure that it is truly embracing the strategic intent of being "customer centric" AND it requires the establishment of a corporate culture that supports both customer and employee engagement.

We recommend having meaningful two-way dialogue with employees (and others) to leverage the results from your 2013 customer satisfaction survey derived from speaking with 632 CHEC Group customers [April 10 - April 23, 2013]. After-all, people can't care about the things that they don't know about.

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June, 2013

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Satisfaction (pre & post)

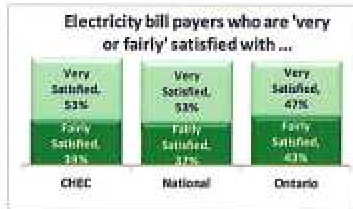
The old adage "You cannot command respect, you have to earn respect" is a lesson that aptly describes the loyalty effect with customers. Many people mistakenly think doing a good job will lead to loyalty; that a satisfied customer equals a loyal customer.

While private industry companies are compelled to understand their customers in order to drive sales and revenue, customer satisfaction measurement can form a similar focus for organizations in the absence of the commercial imperative, such as utilities which operate under monopolistic conditions. It can also help to build a connection with customers and front-line staff, and provide a uniting, motivating factor across the organization. Monopolies are not really different in what they should measure except that trying to determine which customers are "loyal" or "at risk" is not about their future behaviour but more about their "attitudinal" loyalty (are they advocates?). In the private sector customer satisfaction and loyalty are often seen as essential for survival and success. Public sector organizations, especially municipalities, have come to realize that looking after their customers and taking the opportunity to learn from them is key to delivering services which are both effective and efficient.

After 15 years of continued research with electric utility customers, expectations of their electric utility go far beyond "keeping the lights on", "billing me properly", and "restoring power quickly".

- **Satisfaction** happens when utility core services meet or exceed customer's needs, wants, or expectations.

- **Loyalty** occurs when a customer makes an emotional connection with their electric utility on a diverse range of expectations beyond core services.



Satisfaction alone does not make a customer loyal; a willingness to commit and advocate for a company along with satisfaction identifies the three basic customer attitudes which underpin loyalty profiles. While satisfaction is an important component of loyalty, the loyalty definition needs to incorporate more attitudinal and emotive components.

Electricity bill payers who are 'very or fairly' satisfied with...

	2013	2012	2011	2010
CHEC	92%	-	-	-
National	90%	85%	89%	86%
Ontario	90%	86%	84%	80%

Base: total respondents / (-) not a participant of the survey year

Our research has found that in the utility industry environment, especially in Ontario, where most utilities are municipally owned, satisfaction is a strong driver of customer trust as well as, impacts employee engagement. The satisfaction of public customers/citizens both improves employee engagement and is improved by it.

The synergy which exists between customer satisfaction and employee engagement has enormous implications for the performance of those who make up a utility's workforce. Many service personnel are motivated by their desire to help others; succeeding at this task (and having clear evidence that they have satisfied their "customers") can help keep them motivated and engaged.

Satisfied employees, who are working in an organizational culture which promotes service excellence is critical, too. Many companies make the mistake of measuring only customer satisfaction. Measuring organizational culture is the key because employees play an integral role in the customer relationship.

Employees do more than deliver customer service – they personalize the relationship between customer and the utility.

Creating loyal customers and loyal employees go hand in hand and it is the leaders of organizations that must create this alignment. Implementing service excellence works best when its principles are well understood and widespread collaboration is encouraged by management's visible actions. In our experience, this is best achieved by driving change from the 'top down' at the same time as inspiring and fully engaging employees from the 'bottom up'.

In the Simul/UtilityPULSE Customer Satisfaction survey, the overall satisfaction question is asked both at the beginning (PRE) and the end (POST). Asking the general satisfaction question at the start of the survey avoids bias and we obtain a spontaneous rating. This allows measurement of customers' overall impressions of the utility prior to prompting them to think of specific aspects of the relationship. After we have asked about specific aspects of the customer experience, we gain a more *considered* (or conditioned) response.

Base: total respondents

SATISFACTION SCORES – Electricity customers' satisfaction			
Top 2 Boxes: 'very + fairly satisfied'	CHEC	National	Ontario
PRE: Initial Satisfaction Scores	92%	90%	90%
POST: End of Interview	94%	91%	90%

Base: total respondents

SATISFACTION SCORES – Electricity customers' satisfaction				
Top 2 Boxes: 'very + fairly satisfied'	2013	2012	2011	2010
PRE: Initial Satisfaction Scores	92%	-	-	-
POST: End of Interview	94%	-	-	-

Base: total respondents / (-) not a participant of the survey year

Customers, as human beings, are both rational and emotional. The rational side of the customer holds the LDC accountable for doing its job (as contracted), thereby fulfilling the customer's basic needs. The emotional side of the customer is about fulfilling expectations. Meeting rational needs – at best – gets the customer to a neutral state and at worst creates dissatisfaction. Emotional needs, when met, assuming base level rational needs are met, can move a customer from neutral to higher levels of satisfaction.

Attributes strongly linked to a hydro utility's image			
	CHEC	National	Ontario
RATIONAL NEEDS			
Provides consistent, reliable energy	91%	90%	90%
Quickly handles outages	90%	88%	86%
Accurate billing	88%	85%	86%
Provides good value for money	76%	71%	68%
Is 'easy to do business' with	88%	82%	81%
Operates a cost effective hydro-electric system	79%	72%	69%
EMOTIONAL NEEDS			
Deals professionally with customers' problems	88%	83%	84%
Works with customers to keep their energy costs affordable	73%	66%	65%
Pro-active in communicating changes	85%	77%	80%
Quickly deals with issues that affect customers	85%	82%	82%
Adapts well to changes in customer expectations	80%	74%	73%
Overall the utility provides excellent quality services	87%	85%	83%

Base: total respondents with an opinion

Customer Service

Customer service is a series of activities grouped in processes designed to provide customers and other stakeholders with information or assistance which address customer's needs. Those needs are far more diverse than they have ever been thereby, compelling customer service to change in response to increasing customer demands. Given the increase in fragmentation of customer type and customer problems the need for building a customer-centric culture in line with customers' needs, preferences and expectations is important when customer satisfaction is important to the organization.

Customers don't want to be passed from CSR to CSR, unnecessary bureaucracy, to keep repeating why they are calling, to duplicate information already given, or to have to understand the inner workings of the utility organization.

Respondents were asked about six aspects of their most recent experience with a representative from CHEC Group.

- Information – quality of information provided
- Staff attitude – level of courtesy
- Professionalism – the knowledge of staff
- Delivery – helpfulness of staff
- Timeliness – the length of time it took to get what they needed
- Accessibility – how easy it was to contact someone

Base: total respondents who contacted the utility

Satisfaction with Customer Service			
Top 2 Boxes: 'very + fairly satisfied'	CHEC	National	Ontario
The time it took to contact someone	90%	77%	72%
The time it took someone to deal with your problem	83%	73%	69%
The helpfulness of the staff who dealt with you	85%	78%	73%
The knowledge of the staff who dealt with you	86%	74%	72%
The level of courtesy of the staff who dealt with you	89%	85%	82%
The quality of information provided by the staff who dealt with you	75%	77%	70%

Base: total respondents who contacted the utility

The customer service representative's role is essential to effectively handling customer issues/incidents/problems/requests. Having a skilled, trained representative is vital for a positive customer experience when a customer decides to make contact. Respondents who did have contact with a utility representative within the last 12 months were asked about their overall satisfaction with *that* experience.

Overall satisfaction with most recent experience			
	CHEC	National	Ontario
Top 2 Boxes: 'very + fairly satisfied'	76%	81%	78%

Base: total respondents who contacted the utility

This year we asked respondents to approximate the time since their most recent contact.

Approximation of how long ago most recent contact was made	
	CHEC
12+ months ago	6%
7-12 months ago	9%
4-6 months ago	16%
3 or less months ago	63%

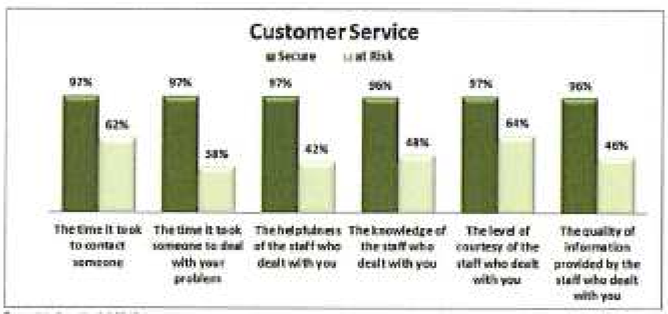
Base: total respondents who tried to contact the utility in the past 12 months

Customers value speed and responsiveness especially as it relates to solving problems. The more flexibility you're able to offer and the more empowerment given to employees, the better able employees will be to meet those "speed" and "responsiveness" requirements. Customers benefit, too, when employees are able to resolve problem issues "on the spot" instead of having to "talk to my manager."

SATISFACTION SCORES – Electricity customers' satisfaction			
National	National	Problems Solved	Problems Not Solved
Top 2 Boxes: 'very + fairly satisfied'	90%	93%	55%
Bottom 2 Boxes: 'fairly + very dissatisfied'	8%	5%	44%

Base: total respondents from 2013 National Benchmark survey

Empowerment is the backbone of the service recovery principle. In the face of error or problems, acting quickly and decisively, being empowered and turning a dissatisfied customer into a satisfied one tends to have a positive impact.



Base: data from the full 2013 database

Satisfaction with Customer Service			
Top 2 Boxes: 'very + fairly satisfied'	Overall	Recent Experience Very Satisfied	Recent Experience Very Dissatisfied
The time it took to contact someone	80%	92%	45%
The time it took someone to deal with your problem	77%	95%	17%
The helpfulness of the staff who dealt with you	80%	98%	21%
The knowledge of the staff who dealt with you	80%	97%	21%
The level of courtesy of the staff who dealt with you	87%	97%	40%
The quality of information provided by the staff who dealt with you	77%	96%	21%

Base: data from the full 2013 database

Important attributes which shape perceptions about service quality	CHEC	National	Ontario
Is pro-active in communicating changes and issues which may affect customers	85%	77%	80%
Trusted and trustworthy company	89%	83%	83%
Respected company in the community	89%	83%	84%
Provides good value for money	76%	71%	68%
Customer-focused and treats customers as if they're valued	84%	76%	77%
Deals professionally with customers' problems	88%	83%	84%
Is a company that is 'easy to do business with'	88%	82%	81%
Quickly deals with issues that affect customers	85%	82%	82%
Provides information and tools to help manage electricity	84%	79%	80%
Adapts well to changes in customer expectations	80%	74%	73%
Delivers on its service commitments to customers	89%	85%	87%
Uses responsible business practices when completing work	89%	85%	86%

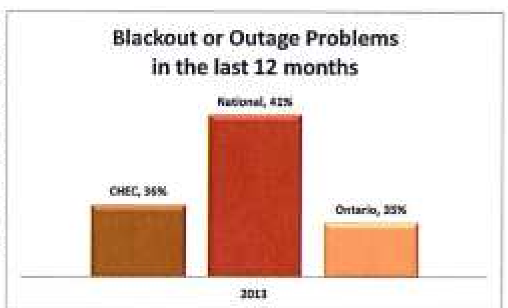
Base: total respondents with an opinion

The service experience has a profound impact on customer service scores. The data shows a direct correlation between a very satisfied customer experience and the ratings given across all six measures of customer service. While there are a lot of things utilities cannot control, one thing they can control is the quality of service they provide.

Bill payers' recent problems and problem resolution

Outages and billing problems, we call them the "Killer B's", the two issues that are most likely to cause grief to utility customers.

At one time, if the power went off for a few minutes, it was considered annoying and inconvenient. However, with the onset of computers and smart appliances in homes and businesses, a power outage is now unbearable. Customers have little tolerance for an interruption in their flow of electricity.



Base: total respondents

While blackouts are rare, each one has the potential of affecting thousands of people. Think of the thousands of football fans at Super Bowl 2013 who sat in darkness for 38 minutes.

Besides the mere inconvenience an outage creates, economic loss is a principal concern. Typically during an outage, employees are unable to do their work because computers and other equipment are not able to operate. An outage therefore causes an employer to pay wages to idle employees, potentially causes employers to deal with overtime work to clear the backlog created by the down time. Outages also could potentially threaten life by interfering with the operation of life-support equipment i.e. those requiring life-support equipment i.e. ventilators for those afflicted with paralysis (although these instances would be rare and uncommon, the risk and potential liability do exist).

Despite a utility's best efforts, there will be times when the power goes off.

Percentage of Respondents indicating that they had a Blackout or Outage problem in the last 12 months			
	CHEC	National	Ontario
2013	36%	41%	35%
2012	-	44%	46%
2011	-	43%	43%
2010	-	45%	41%

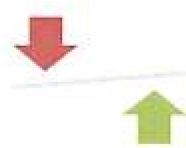
Base: total respondents

Reliability of service needs to be always given primary importance by electric utility systems. Reliability to a customer means that power made available to them is fault free and the outage or interruptions are tolerable and do not disturb their 'normal life'. Customer satisfaction can be improved through providing better quality power in terms of voltage and frequency fluctuations and reliability by reducing outages.

A "pain point" such as a power outage which will cause grief and could anger some customers will impact customer satisfaction scores.

Bill payers recalling a power failure or outage				
	Secure	Favorable	Indifferent	At Risk
Yes	19%	24%	34%	39%
No	80%	75%	65%	61%

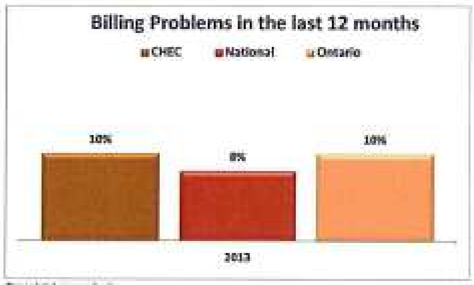
Base: data from the full 2013 database



Even though outages can have a negative impact on satisfaction, utility providers who manage these incidents properly-by providing sufficiently detailed information about the outage and restoring power when they say they will-may be able to mitigate declines, or even improve satisfaction.

For most customers, their bill is the only thing they see (or pay attention to) from their utility provider. It not only tells them how much to pay, it documents their service usage, breakdowns the various charges and provides contact information for customer service. As the principal form of communication between a utility and its customers, utilities cannot underestimate the importance of billing.

When it comes to billing, customers expect zero-defect delivery. Customers expect timely and accurate billings which they understand. Incorrect information, miscalculated balances, bills that are too difficult to understand result in time logged by your CSR's as well as dissatisfied customers. Improving billing activities has an immediate impact on the revenue streams of a utility, in terms of costs associated with managing call center applications.



Base: total respondents

Percentage of Respondents indicating that they had a Billing problem in the last 12 months

	CHEC	National	Ontario
2013	10%	8%	10%
2012	-	12%	13%
2011	-	10%	16%
2010	-	10%	12%

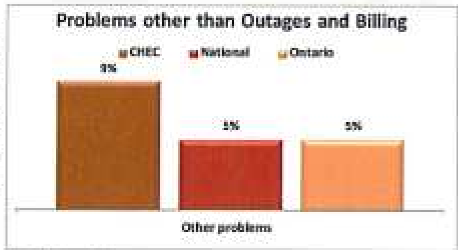
Base: total respondents / (-) not a participant of the survey year

Types of Billing Problems

	CHEC
The amount owed was too high	40%
The bill was difficult to understand	13%
Complaint about rates or charges	11%
The bill arrived late	11%
Notice to terminate	6%
No bill/skipped bill	6%
The payment made was recorded incorrectly	3%

Base: total respondents with billing problems

As it relates to problems, the Killer B's – Bills and Blackouts still occupy top ranking – while moving/setting up a new account, maintenance repairs, high bills, information on pricing, SMART meters and energy conservation are issues which also contribute to inbound call-centre calls.



Base: total respondents

A customer who has experienced a problem or unfavourable service experience may spread negative word-of-mouth communication. While people have long complained about service providers in offline meeting places such as work lunch rooms, or social gatherings, today's social networks and online discussion forums mean such gripes often reach a considerably wider audience.

By understanding the complaint process and customer complaint behaviour, a utility can learn how to reduce the impact of an unfavourable service experience or complaint.

Our 15 years of research corroborates the notion that customer dissatisfaction and the handling of service recovery are key indicators of customer loyalty. A complaint allows the utility to obtain

customer feedback that is useful in making improvements to increase customer satisfaction and loyalty. Effective resolution of customer problems can have a positive impact on customers' trust and commitment. The complaint handling process therefore, is a series of critical "moments of truth" in maintaining and developing customer relationships.

Percentage of Respondents with problems other than billing or power outages in the last 12 months

	CHEC	National	Ontario
Yes	9%	5%	5%
No	91%	95%	95%

Base: total respondents

Percentage of Respondents who contacted their utility and had their problem solved in the last 12 months

	CHEC	National	Ontario
Yes	69%	73%	74%
No	20%	19%	19%

Base: total respondents

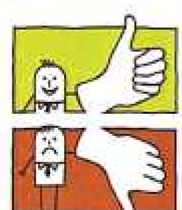
Utilities need to ensure that their customer complaint/service recovery processes are made to be more responsive and proactive. CSRs need to be capable enough to meet the growing demand of information conscious and tech savvy customers. Every minute counts when it comes to complaints being voiced with the aid of social media.

Attributes describing operational effectiveness	Overall Score	Problem Solved	Problem Not Solved
Provides consistent, reliable energy	91%	90%	81%
Delivers on its service commitments to customers	87%	86%	72%
Accurate billing	87%	85%	65%
Quickly handles outages and restores power	89%	88%	80%
Makes electricity safety a top priority	90%	91%	83%
Uses responsible business practices when completing work	88%	87%	76%
Is efficient at handling the hydro-electric systems	84%	83%	73%
Is a company that is 'easy to do business with'	85%	85%	63%
Operates a cost effective hydro-electric system	75%	73%	58%
Overall the utility provides excellent quality services	87%	86%	69%

Base: data from the full 2013 database from those respondents with an opinion

Technology is considered by many in the electricity utility industry to be both a blessing and a curse. On one hand, the LDC (and other service providers) can benefit from embracing technology to reduce costs and hopefully improve service thereby, putting control into the hands of the customer. On the other, when the problem has not been solved or is handled poorly, technology can enable the customer's dissatisfaction to go viral – the impact is on overall satisfaction with customers as well as employees.

Customer Experience Performance rating (CEPr)



New for 2013 is the Customer Experience Performance rating (CEPr). Every touch point with customers on the phone, website or in-person influences what customers think and feel about the organization. The key is handling every individual element of an interaction with a customer so that he/she feels good at the end of the whole interaction and the utility achieves its business objectives.

Great experiences occur when all functions of the organization align with one another to achieve the outcomes your customers seek. A good customer experience starts with understanding what your customers care about most and understanding which promises are most important to your customers.

At the heart of the CEPr are 4 central questions:

- Are interactions with the organization professional and productive?
- Is the organization 'easy to deal with'?
- Does the organization effectively meet your needs?
- Does the organization provide high quality services?

Some of the factors which contribute to the overall Customer experience:

- Delivering accessible and consistent customer service
- Understanding customer expectations
- Maintaining timely resolution timelines
- Providing effective communication(s) according to customer needs
- Demonstrating responsiveness
- Speeding up problem resolution
- Conducting problem analysis to prevent recurring issues
- Easy to do business with
- Seeking customer feedback and following through on recommendations

Customer Experience Performance rating (CEPr)			
	CHEC	National	Ontario
CEPr: all respondents	87%	83%	83%
CEPr: respondents *who have* contacted their utility	83%	79%	77%
CEPr: respondents *who have not* contacted their utility	89%	84%	85%

Base: total respondents

The CEPr (all respondents) for CHEC Group is 87%. On the surface this rating appears to be very high (and it is). But put the rating in context – it would mean that a very large majority of customers have a belief that they will have a good to excellent experience dealing with a CHEC Group professional. However, the balance of respondents are not anticipating a good to excellent experience, and as such could be more challenging to serve.

While an excellent transaction today creates a positive experience today, the perception created is that future transactions will be excellent too, which is how you want your customers to feel. Of course a negative transaction creates the perception that future transactions will be negative. The key then is to emphasize problem resolution with a "one call" mindset.

The impact of Very Satisfied or Very Dissatisfied experiences on some operational attributes			
CHEC	Overall Score	Recent Experience Very Satisfied	Recent Experience Very Dissatisfied
Provides consistent, reliable energy	91%	94%	85%
Delivers on its service commitments to customers	89%	93%	88%
Accurate billing	88%	90%	77%
Quickly handles outages and restores power	90%	93%	78%
Makes electricity safety a top priority	90%	95%	94%
Uses responsible business practices when completing work	89%	94%	91%
Is efficient at handling hydro-electric systems	88%	91%	81%
Overall the utility proves excellent quality services	87%	91%	78%

Base: respondents who have contacted the utility

Customer Engagement Index (CEI)

The UtilityPULSE Customer Engagement Index (CEI) is a metric designed to get a more in-depth look at the attachment a customer has with your LDC and its brand.

What is Customer Engagement?

Ask 10 pundits, experts or academics about the definition of customer engagement and you will not get a consistent answer. UtilityPULSE has been researching this topic for the past 2 years and we have found that there are 4 basic types of definitions associated with the term called "customer engagement". Here are the basic types:

1- Participation in programs or service offerings
2- Pro-active "reach-out" to customers
3- Customer loyalty
4- How customers think, feel and act towards the organization that serves them.

Ultimately, one has to decide if customer engagement is a program, or an outcome? Basic types 1 & 2 as shown above would suggest that engagement is a program. Types 3 & 4 are outcome based definitions. Drawing from our 25+ years of experience working with enterprises in both the private and

public domains, we believe that basic types 1 & 2 are too simplistic and tend to be efficiency measurements. Whereas types 3 & 4 are more valuable to the organization especially when a key corporate goal is to create an operationally effective place to do business with, essentially they are effectiveness and outcomes oriented measurements.

Your Annual UtilityPULSE survey tracks a customer's willingness to continue to do business, and willingness to recommend their local utility. Through a combination of calculations the end result is a Customer Loyalty index. That is, the number of customers that are: At risk, Indifferent, Favourable, Secure. The goal of every enterprise ought to be the creation of more Secure and Favourable customers. We believe that high levels of customer engagement correlate strongly to high levels of Secure and Favourable customer numbers.

We believe that a customer-centric definition of engagement is more valuable to individuals, teams and executives in an LDC for determining what needs to be done to ensure that the organization is successful today and successful again tomorrow – in a changed world.

Engagement is how customers think, feel and act towards the organization. As such, ensuring that customers respond in a positive way requires that they are rationally satisfied with the services provided AND emotionally connected to your LDC and its brand. The more frequently and consistently an organization's products and services can connect with a customer, especially on an emotional level, the stronger and deeper the customer becomes engaged with the organization.

What does an engaged customer look like?

UtilityPULSE has identified the six key dimensions of what defines customer engagement. They are: empowered, valued, connected, inspired, future oriented and performance oriented.

They include:

- Does the utility allow their customers to feel ***empowered*** about their interactions with the company and decisions affecting their electricity usage
- Does the utility give customers the sense of being ***valued***
- Does the utility act in ways which allows customers to stay ***connected***
- Do customers get ***inspired*** by the way the utility conducts business
- Is the utility forward thinking enabling customers to be ***future oriented***
- Does the utility conduct operations in such a way that customers believe that they are truly ***performance oriented*** in achieving goals and results

Utility Customer Engagement Index (CEI)

	CHEC	National	Ontario
CEI	80%	81%	81%

Base: total respondents

UtilityPULSE Report Card®

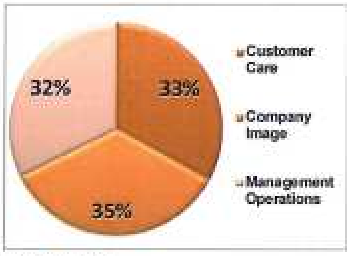
Simul's UtilityPULSE Report Card® is based on tens of thousands of customer interviews gathered over fifteen years. The purpose of the UtilityPULSE Report Card® is to provide electric utilities with a snapshot of performance – on the things that customers deem to be important. Research has identified over 20 attributes, sorted into six topic categories (we call these drivers), that customers have used to describe their utility when they have been satisfied or very satisfied with their utility. These attributes form the nucleus, or base, from which "scores" are assigned. Customer satisfaction and loyalty also play a major role in the calculations.

There are two main dimensions of the UtilityPULSE Report Card® the first is Customer psyche and the other is Customer perceptions about how the utility executes its business.

The Psyche of Customers

Every utility has virtually the same responsibility – provide safe and reliable electricity – yet not all customers are the same. The following chart shows the weight or significance of each category to the customer when forming their overall impression of the utility. Three major themes, each with two major categories make up the UtilityPULSE Report Card®. In effect the Report Card provides feedback about your customers' perception on the importance of each category and driver – as it relates to the benchmark.

UtilityPULSE Report Card® for CHEC Group



Base: total respondents

The UtilityPULSE Report Card® also provides customer perceptions about how your utility executes or performs its responsibilities. This is different, very different, from what a customer might say about a major concern or worry that they have about electricity. As our survey has shown since its inception the primary suggestion for improvement is "reduce prices", which is also a major concern which your customers have about municipal taxes, gas for the vehicle, and other utilities.

Readers of this report should note that the categories and drivers are interdependent. Which means that, for example, failure to provide high levels of power quality and reliability will have a negative impact on customer perceptions as it relates to customer service. Customer care, when it doesn't meet customer expectations has a negative impact on Company Image, etc.

Defining the categories and major drivers:

Category: Customer Care

Drivers: Price and Value; Customer Service

Just because everyone likes good customer care, that in and by itself, is not a reason to provide it – though it may be important to do so. In highly competitive industries good customer service may be a differentiating factor. The case for electric utilities is simple, high levels of customer care result in less work (hence cost) of responding to customer inquiries and higher levels of acceptance of the utility's actions.

Price and Value:

Customers have to purchase electricity because life and lifestyle depend on it. This driver measures customer perceptions as to whether the total costs of electricity represent good value and whether the utility is seen as working in the best interests of its customers as it relates to keeping costs affordable.

Customer Service:

Customers do have needs and every now and again have to interface with their utility. How the utility handles various customers' requests and concerns is what this driver is all about. Promptly answering inquiries, providing sound information, keeping customers informed and doing so in a professional manner are the major components of this driver.

Category: Company Image

Drivers: Company Leadership; Corporate Stewardship

Utilities have an image even if they do not undertake any activities to try to build it.

A company's image is both a simple and complex concept. It is simple because companies do create images that are easily described and recognized by their target customers. It is complex because it takes many discrete elements to create an image which includes, but is not limited to: advertising, marketing communications, publicity, service offering and pricing.

An electric utility trying to manage its image has one more challenge to deal with, and that is the electric industry itself. There are so many players that residential customers (in particular) don't know who does what or who is responsible for what. So when there are political or regulatory announcements, the local utility is often swept up into the collective reaction of the population.

Company Leadership

This driver is comprised of customer perceptions as it relates to industry leadership, keeping promises and being a respected company in the community.

Corporate Stewardship

Customers rely on electricity and want to know that their utility is both a trusted and credible organization that is well managed, is accountable, is socially responsible and has its financial house in order.

Category: Management Operations

Drivers: Operational Effectiveness; Power Quality and Reliability

Electrical power is the primary product which utilities provide their customers and, they have very high expectations that the power will be there when they need it. Customers have little tolerance for outages. The reality is, every utility has to get this part right…no excuses. It is the utility's core business. This category and its drivers are clearly the most important for fulfilling the rational needs of a utility's customers.

Operational Effectiveness

This driver measures customers' perceptions as they relate to ensuring that their utility runs smoothly. Attributes such as: accurate billing and meter reading, completing service work in a professional and timely manner and maintaining equipment in good repair are deemed as important to customers.

Power Quality and Reliability

Power outages are a fact of life – and, customers know it. They expect their utility to provide consistent, reliable energy, handle outages and restore power quickly and make using electricity safely an important priority.

CHEC's UtilityPULSE Report Card®

Performance

	CATEGORY	CHEC	National	Ontario
1	**Customer Care**	A	B+	B+
	Price and Value	B+	B	B
	Customer Service	A	B+	A
2	**Company Image**	A	A	A
	Company Leadership	A	A	A
	Corporate Stewardship	A	A	A
3	**Management Operations**	A	A	A
	Operational Effectiveness	A	A	A
	Power Quality and Reliability	A+	A	A
	OVERALL	A	A	A

Base: total respondents

As the UtilityPULSE Report Card® shows, the total customer experience with an electric utility is defined as more than "keeping the lights on". Customers deal with your utility every day for a variety of reasons, most likely because they need someone to help them solve a problem, answer a question or take their order for service. All your employees, from customer service representatives to linemen, leave a lasting impression on the customers they interact with. In effect there are many moments of truth. Moments of truth are every customer touch point that a utility has with their customers. Therefore, managing these moments of truth creates higher levels of Secure customers while reducing the number of At Risk customers that exist.

It's the small things done consistently that matter: Things like greeting every customer, whether on the phone or in person, in a friendly and helpful manner. Things like listening to the customer's needs, providing solutions to their problems and showing appreciation to the customer for their business.

For communication, utilities now recognize customer communications as a valuable aspect of their business. The better a utility communicates with customers, in a manner that speaks to them, the more satisfied they are with their overall service. "Sending out information" is not the same as having a "conversation" with a customer. We believe that it is increasingly important to channel your communications to the various customer segments which exist.

Obviously employees – in every area – play a critical role in customer service success. Consequently how they feel about their job responsibilities and role in the company will be communicated indirectly through the level of service which they actually provide customers with whom they interact. The reality is engaged employees are the key to excellent customer care.

Our survey work with employees shows that there are many elements of an organizational culture to support the people model needed to achieve high levels of engagement. Our research has identified 6 main drivers that promote and support people giving their best: feeling empowered, valued, belonging, inspired, growing and performance oriented. There are 12 key processes from "attracting employees" to "saying goodbye to employees" that are part of your people model to get the best performance from every employee.

We believe that taking the time to understand the difference between employee satisfaction and organizational culture is worthwhile from a resourcing perspective and from a people development perspective. Every organization has a culture – we believe that it is a leadership imperative to install and maintain a culture that ensures that you attain the achievements and successes of your utility's many investments in people, technology and equipment.

The Loyalty Factor

If a customer is satisfied, it doesn't necessarily mean he or she is loyal. Satisfaction is about fulfilling promises/expectations; loyalty goes way beyond that by creating exceptional experiences and long-lasting relationships. There is a reason why marketing campaigns strive to build brand loyalty, not brand satisfaction. Measuring customer loyalty in an industry where many customers don't have a choice of providers doesn't make sense. Or does it?

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The answer depends on how you define "customer loyalty."

Private industry often equates customer loyalty with basic customer retention. If a customer continues to do business with a company, that customer is, by definition, considered to be loyal. If this definition were applied to many companies in the utility industry, all customers would automatically be considered loyal. As such, measuring customer loyalty would appear to be unnecessary.

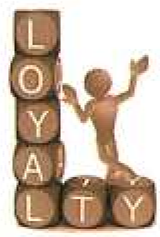
Natural monopolies (like LDCs) are not really different in what they should measure except that trying to determine which customers are "loyal" or "at risk" is not about their future behaviour but more about their "attitudinal" loyalty (are they advocates?).

Perhaps a better or more relevant way for utilities to approach the definition of customer loyalty is to further expand how they think about loyalty. Consider the following definition: Customer loyalty is an emotional disposition on the part of the customer that affects the way(s) in which the customer (consistently) interacts, responds or reacts towards the company – its products & services and its brand.

So what does it mean to respond favourably to a company? At a basic level, this can mean choosing to remain a customer. As previously mentioned however, this is essentially a non-issue for many utility companies. It then becomes necessary to think beyond just customer retention. One needs to consider other ways in which customers can respond favourably toward a company.

Other favourable responses or behaviours can be classified into one of three categories that reflect the concept of customer loyalty:

- Participation
- Compliance or Influence
- Advocacy



Specific examples of potential participatory behaviour in the electric utility industry include:

- Signing up for programs that help the customer reduce or manage their energy consumption
- Using the utility as a consultant when selecting energy products and services from a third party
- Participating in pilot programs or research studies

Specific examples of potential compliance or influence behaviours that utility customers might exhibit include:

- Seeking the utility's advice or expertise on an energy-related issue
- Voluntarily cutting back on electricity usage if the utility advised the customer to do so
- Accepting the utility's energy advice or referrals to energy contractors or equipment
- Being influenced by the utility's opinion regarding energy- management advice, equipment, or technologies
- Providing personal information that enables the utility to better serve the customer
- Paying bills online

Creating customer advocates can be especially important for a company in a regulated industry. In the absence of customer advocates, or worse, in a situation where customers speak unfavourably about a company or actively work to support issues that are counter to those the company supports, companies can suffer a variety of negative consequences like increased business costs, lawsuits, fines and construction delays. For an electric utility, specific examples of potential advocacy behaviour include:

- Supporting the utility's positions or actions on energy-related public issues, including the environment
- Supporting the utility's position on the location and construction of facilities
- Providing testimonials about positive experiences with the utility

In sum, loyal behaviour in the utility industry may not be as evident as it is in a more competitive environment. Measuring customer loyalty in a generally non-competitive industry requires one to think about loyalty in non-traditional ways. Customer loyalty is an intangible asset that has positive consequences or outcomes associated with it no matter what the industry. Properly measuring loyalty among utility customers requires thoughtful probing to thoroughly identify the range of participation, compliance, and advocacy behaviours that will ultimately benefit the company in meaningful ways, and foster happier and more loyal customers.

The UtilityPULSE Customer Loyalty Performance Score segments customers into four groups: **Secure** – the most loyal - **Still Favorable**, **Indifferent**, and **At risk**.

Secure customers are "very satisfied" overall with their local electricity utility. They have a very high emotional connection with their utility and definitely would recommend their local utility.

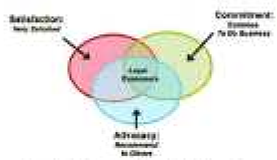
Still favorable customers are "very satisfied" overall, "definitely" or "probably" would recommend their local utility and not switch if they could.

Indifferent customers are less satisfied overall than secure and still-favorable customers and less inclined to recommend their local utility or say they would not switch.

At risk customers, who are "very dissatisfied" with their electricity utility, "definitely" would switch and "definitely" would not recommend it.

Loyalty is driven primarily by a company's interaction with its customers and how well it delivers on their wants and needs.

Customer Loyalty Model

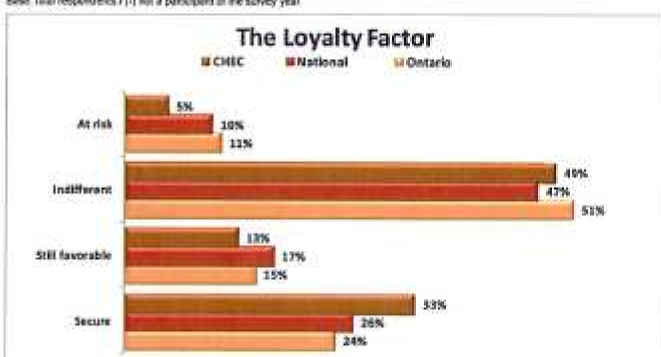


Loyalty is based on likelihood to:

- ***Satisfaction:*** *overall satisfaction*
- ***Commitment:*** *continue as a customer*
- ***Advocacy:*** *willingness to recommend*

Customer Loyalty Groups				
	Secure	Favorable	Indifferent	At Risk
CHEC				
2013	33%	13%	49%	5%
2012	-	-	-	-
2011	-	-	-	-
2010	-	-	-	-

Base: Total respondents / (-) not a participant of the survey year



Customer Loyalty Groups				
	Secure	Favorable	Indifferent	At Risk
Ontario				
2013	24%	15%	51%	11%
2012	20%	13%	53%	14%
2011	17%	13%	54%	16%
2010	21%	12%	52%	15%
National				
2013	26%	17%	47%	10%
2012	30%	13%	46%	11%
2011	28%	14%	46%	12%
2010	17%	14%	60%	9%

Base: total respondents

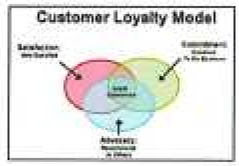
Secure customers' experiences and perceptions are distinct from those of Indifferent customers. There is yet an even greater gap between those identified as Secure versus At Risk.

- Problems are experienced and remain unresolved far more often by the Indifferent or At Risk segments in comparison to others. This is not an unusual finding.
- Other areas of interaction also revealed considerable differences among the segments. Consistently, Secure customers' perceptions are most positive.

Important attributes which shape perceptions about customer affinity			
	Overall Score	Secure	At Risk
Customer focused and treats customers as if they're valued	81%	95%	51%
Is pro-active in communicating changes and issues which may affect customers	82%	94%	59%
Deals professionally with customers' problems	86%	97%	62%
Works with customers to keep their energy costs affordable	70%	87%	40%
Quickly deals with issues that affect customers	84%	96%	60%
Delivers on its service commitments to customers	87%	97%	62%
Provides information and tools to help manage electricity consumption	83%	94%	61%
Is 'easy to do business with'	85%	98%	57%
Adapts well to changes in customer expectations	77%	91%	49%
The cost of electricity is reasonable when compared to other utilities	65%	81%	38%
Provides good value for your money	73%	89%	39%
Provides consistent reliable energy	91%	99%	80%
Operates a cost effective hydro-electric system	75%	91%	44%
Overall the utility provides excellent quality services	87%	98%	64%

Base: data from the full 2013 database from those respondents with an opinion

Customer commitment



Customer loyalty is a term that can be used to embrace a range of customer attitudes and behaviours. One of the metrics used to gauge loyalty is the measure of **retention**, or intention to buy again; this loyalty attitude is termed **commitment.**

Customer commitment to the local electricity supplier is a very important driver of customer loyalty in the electricity service industry. In a similar way to trust, commitment is considered an important ingredient in successful relationships. In simpler terms, commitment refers to the motivation to continue to do business with and maintain a relationship with a business partner i.e. the local utility.

For electric utilities, this measurement is about identifying the number of customers who feel that they "want to" vs "have to" do business with you. Potential benefits of commitment may include word of mouth communications - an important aspect of attitudinal loyalty. Committed customers have been known to demonstrate a number of beneficial behaviours, for example committed customers tend to:

- Come to you. One of the key benefits of establishing a good level of customer loyalty is that customers will come to you when they need a product or service.

- Validate information received from 3rd parties with information and expertise that you have.
- Try new products/initiatives.
- Perhaps they will even trust you when recommendations are made.
- Be more price tolerant.
- More receptivity of utility viewpoints on various issues.
- More tolerance of errors or issues that inevitably take a swipe at the utility.
- Stronger levels of perception regarding how the utility is managed.

Though customers can not physically leave you, they can emotionally leave you and when they do, it becomes an extreme challenge to garner their participation or support for utility initiatives.

Electricity customers' loyalty – ... Is a company that you would like to continue to do business with

	CHEC	National	Ontario
Top 2 Boxes: 'Definitely + Probably' would continue	85%	79%	80%
Definitely would continue	55%	47%	48%
Probably would continue	30%	31%	33%
Might or might not continue	7%	6%	6%
Probably would not continue	1%	4%	5%
Definitely would not continue	2%	6%	6%

Base: total respondents

Electricity customers' loyalty – … is a company that you would like to continue to do business with

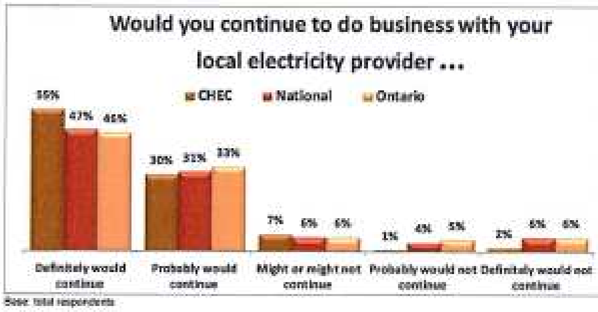
CHEC	<$40K	$70K+	18-34	55+
Top 2 Boxes: 'Definitely + Probably' would continue	90%	88%	92%	87%

Base: total respondents

Electricity customers' loyalty – is a company that you would like to continue to do business with

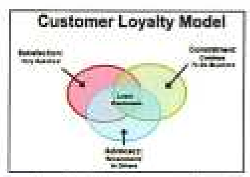
CHEC	2013	2012	2011	2010
Top 2 boxes: 'Definitely + Probably' would continue	85%	-	-	-

Base: total respondents / (-) not a participant of the survey year



Base: total respondents

Word of mouth



Advocacy is one of the metrics measured in determining customer loyalty. Essentially, companies believe that a loyal customer is one that is spreading the value of the business to others, leading new people to the business and helping the company grow. Customer referrals, endorsements and spreading the word are extremely important forms of customer behaviour. For LDCs this is about generating positive referants about the LDC as a relevant and valuable enterprise.

When customers are loyal to a company, product or service, they not only are more likely to purchase from that company again, but they are more likely to recommend it to others – to openly share their positive feelings and experiences with others. In today's world, thanks to the Internet, they can tell and influence millions of people. That equates to new customers and revenue. The same holds true, if not more, when customers are disloyal. Disgruntled customers could share their negative experiences with an ever-widening audience, jeopardizing a company's reputation and resulting in fewer engaged customers and/or customers who are Favourable or Secure. Secure customers, typically are advocates and they are deeply connected and brand-involved.

There are two forms of word of mouth which utilities need to understand. The first is Experience-based word of mouth which is the most common and most powerful form. It results from a customer's direct experience with the utility or the re-statement of a direct experience from a trusted source.

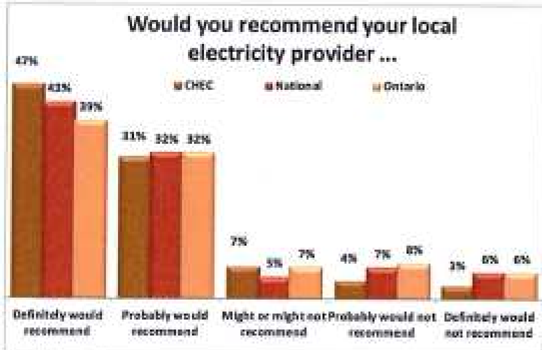
The second is Relay-based word of mouth. This is when customers pass along important messages to others based on what they have learned through the more traditional forms of communications. For example, if the utility was communicating an offer for "free LED lights" chances are high that the offer will be "relayed" to others through word of mouth.

For an electric utility, specific examples of potential positive advocacy behaviour include:

Recommending that other customers specifically locate in the geographic area that is serviced by that utility

- *Supporting the utility's positions or actions on energy-related public issues, including the environment*
- *Supporting the utility's position on the location and construction of facilities*
- *Providing testimonials about positive experiences with the utility*

Would you tell me if you agree or disagree with the following statement? CHEC is a company that you would recommend to a friend or colleague …



Base: total respondents

Word of mouth communication is a very powerful form of communication and influence. When customers are speaking to other customers (or their peers) it is more credible, goes through less perceptual filters and can enhance the view of services or products provided better than marketing communication.

Electricity customers' loyalty – … is a company that you would recommend to a friend or colleague

	CHEC	National	Ontario
Top 2 boxes: 'Definitely + Probably' would recommend	78%	75%	71%
Definitely would recommend	47%	43%	39%
Probably would recommend	31%	32%	32%
Might or might not recommend	7%	5%	7%
Probably would not recommend	4%	7%	8%
Definitely would not recommend	3%	6%	6%

Base: total respondents

Electricity customers' loyalty – is a company that you would recommend to a friend or colleague

CHEC	<$40K	$70K+	18-34	55+
Top 2 boxes: 'Definitely + Probably' would recommend	84%	79%	90%	80%

Base: total respondents

Electricity customers' loyalty – is a company that you would recommend to a friend or colleague

CHEC	2013	2012	2011	2010
Top 2 boxes: 'Definitely + Probably' would recommend	78%	-	-	-

Base: total respondents / (-) not a participant of the survey year

Corporate image

Organizations today are always under scrutiny and have to consider the reality AND perception of their image. In the simplest of terms, how you are seen by your stakeholders is your corporate image and reputation. The corporate image is a dynamic and profound affirmation of the nature, culture and structure of an organization. This applies equally to corporations, businesses, government entities, and non-profit organizations.

The corporate image communicates the organization's mission, the professionalism of its leadership, the caliber of its employees and its roles within the marketing environment or political landscape. Every organization has a corporate image, whether it wants one or not.

All companies survive on the strength of the relationships they build with their customers. To build and maintain a corporate image, a company must express its brand consistently in a wide range of ways including websites, advertising and "information" materials, but also customer service, the look and layout of the workplace and the way the company functions as a whole. Failure to do that can mean a business could, at worst, appear fraudulent, and at best not exploit the brand's potential.

When properly designed and managed, corporate image will accurately reflect the level of the organization's commitment to quality, excellence and relationships with its various stakeholders, including customers, employees, suppliers, partners, governing bodies, and the general public at large. As a result, corporate image is a critical concern for every organization, one deserving the same attention and commitment by senior management as any other vital issue.

Increasingly, organizations have realized that the management of a strong positive image with various stakeholders can be beneficial. Below are some of the attributes measured in the annual UtilityPULSE survey which are strongly linked to a utility's image.

Attributes strongly linked to a hydro utility's image

	CHEC	National	Ontario
Is a respected company in the community	89%	83%	84%
Maintains high standards of business ethics	88%	81%	81%
A leader in promoting energy conservation	85%	80%	80%
Keeps its promises to customers and the community	88%	81%	82%
Beyond providing jobs and paying taxes, is socially responsible	86%	79%	79%
Is a trusted and trustworthy company	89%	83%	83%
Adapts well to changes in customer expectations	80%	74%	73%
Is 'easy to do business with'	88%	82%	81%
Overall the utility provides excellent quality services	87%	85%	83%
Operates a cost effective hydro-electric system	79%	72%	68%

Base: total respondents with an opinion

These attributes measure different facets of reputation such as the extent to which the company is providing excellent quality services, whether the company is known as leader in the industry and respected in the community, how the company delivers value, reliable service and support, how the company efficiently manages its business, the company's approach to making the world a better place - environmental and social commitments, and the emotional connection the company has with the people.

People feel better about themselves when they believe they are dealing with an organization that cares about "doing the right thing". Today, being a good corporate citizen requires more than business as usual, it requires investments in society and the environment.

Our research has shown when customers attribute positive feelings to a utility's corporate visual identity systems, when they think that marketing communication activities reflect corporate values, and when they perceive the company as socially responsible, they tend to form a favourable image of that organization. Our research also shows that customers put more emphasis on an LDC's brand image as an influencer of satisfaction and loyalty today than they did 10-15 years ago.

Corporate Credibility & Trust

No organization or company can plunge trust and credibility among its customers and stakeholders – and survive. Building and maintaining credibility and confidence make up a deliberate process that occurs over numerous interactions usually over a long period of time.

Establishing trust and credibility, whether with business partners, customers or regulators, is not achieved overnight. Creating credibility is a process, which advances only through honest, continuous communication between the utility, its regulators, and the public at large. Credible communications are informed and nurtured by diligent efforts on the utility's part to understand the legal and regulatory framework in which it operates. Public trust in their local utility is the degree to which the public believes that the utility will act in a particular manner because the utility has incorporated the public's interest into its own. The public trusts the utility to produce consistent and reliable electricity.

Attributes strongly linked to a hydro utility's image

	CHEC	National	Ontario
Overall the utility provides excellent quality services	87%	85%	83%
Keeps its promises to customers and the community	88%	81%	82%
Customer-focused and treats customers as if they're valued	84%	76%	77%
Is a trusted and trustworthy company	89%	83%	83%

Base: total respondents with an opinion

Trust and credibility can be thought of as indicators of the degree of confidence stakeholders have in your organization's ability to deliver on its commitments. Trust and credibility are outcomes based on what your utility actually does, not what it might be doing.

SimulUtilityPULSE research shows the under-pinning components which lead customers to believe an organization has credibility and can be trusted are: Knowledge, Integrity, Involvement and Trust.

Knowledge is captured by the utility's ability to demonstrate that it is actively aware of industry, regulatory and economic changes within the industry and how these might impact the lives of customers.

Integrity is established by demonstrating adherence to a code of conduct. It requires consistently acting in accordance with the values and goals that have been communicated to customers.

Involvement — Corporate involvement is increasingly important to Canadian communities as it is an opportunity for their local utility to use their resources and man-power to benefit people at the community level. This helps to build credibility as customers see that the organization is acting and delivering on its commitments. This helps customers regard the utility with esteem and respect.

Trust — Trust is achieved through a track record of consistent and reliable performance, delivering on commitments and demonstrated accountability.

Using the four components of demonstrating Credibility and Trust, the resultant index shows that LDCs enjoy a high level of credibility and trust. As Benjamin Franklin said, "It takes many good deeds to build a good reputation, and only one bad one to lose it."

Credibility and Trust Index
Knowledge The utility is seen as being knowledgeable about the services it provides, about what is happening in the industry, and how customers can reduce costs or create more value.
Integrity The utility is seen as an organization that will act in the best interests of its customers and can be counted on to provide services and resolve problems in a professional manner.
Involvement The utility is actively involved in the industry, in the community and in things that affect the customer.
Trust The utility is an organization that can be trusted and is worthy of respect.
Overall CHEC Group 87% [Ontario 82%; National 82%]

How can service to customers be improved?

Perception is an opinion about something viewed and assessed and it varies from customer to customer, as every customer has different beliefs towards certain services and products that play an important role in determining customer satisfaction.

Customers are more informed, more aware, more conscious of what's going on around big issues in the world around them and in this age of internet and social media, they are better equipped to influence service quality and outcomes. They have learned to compare products and services, to document and monitor customer service and satisfaction, and to request or demand higher quality.

Customer satisfaction is determined by the customers' perceptions and expectations of the quality of the products and services. In many cases, customer perception is subjective, but it provides some useful insights for organizations to develop their marketing strategies. Just as in previous years, respondents were asked once again what their utility could do to improve service.

And we are interested in knowing what you think are the one or two most important things 'your local utility' could do to improve service to their customers?

One or two most important things 'your local utility' could do to improve service	
CHEC	% of all suggestions
Better prices/lower rates	45%
Improve/simplify/clarify billing	12%
Improve power reliability	10%
Concerns about SMART meters	8%
Better communication with customers	8%
Staff related concerns	6%
Information & incentives on energy conservation	5%
Remove hidden costs on bills	5%
Better on-line presence	5%
Be more efficient	4%
Increase service hours/availability of hydro representative	3%
Don't charge for previous debt	3%

Base: total respondents with suggestions

SMART Meters & SMART Grid

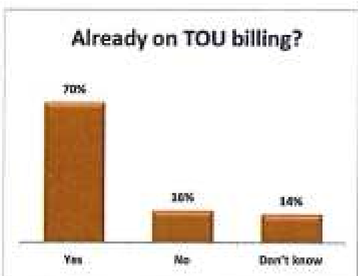
Consumers are used to paying different amounts during different times of day in a variety of settings. In larger cities, drivers pay more for parking when there is higher demand, such as during the day or during special events. Similarly, some highway toll charges increase during commuting hours, while drivers who drive across during off peak hours will save money. Customers even acknowledge that they will pay more for using their cell phone minutes during weekdays rather than nights and weekends.

Demand for energy is going up. Energy prices are climbing. What are customers to do?
Customers can respond to increases in energy prices in one of 3 ways:

(1) changing energy usage behaviour,
(2) investing in energy-using technologies and practices, or
(3) making no change to their energy usage.

Time-of-use (TOU) pricing was designed to reward consumers who shift their load to off-peak times. Electricity rates on weekends and overnight are about half of the cost during peak hours. This is supposed to be an economic incentive for people to shift electricity use to off-peak hours.
There is a direct correlation between customer familiarity with SMART meters and their favourable views toward the technology. While the majority of respondents could identify they were on TOU

billing, a significant proportion were not in the know. Lack of knowledge is a real barrier to ultimate acceptance and/or any type of behaviour modification.

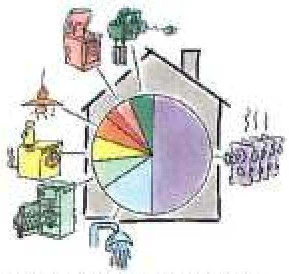


Base: An aggregate of respondents from 2013 participating LDCs / 30% of total respondents from the local utility

Do economic incentives, based on time-tiered pricing, have an impact on resource consumption patterns? Does awareness about electricity use change behaviours? Respondents of the 2013 survey seem to believe they have. *77% agree strongly or somewhat that Time-of-Use billing has changed the way in which they consume electricity on a day-to-day basis. [Base: Ontario LDC respondents]*

Time-of-Use billing has changed the way in which you consume electricity on a day-to-day basis	Ontario LDCs
Agree strongly	42%
Agree somewhat	35%
Neither / Neutral	2%
Disagree somewhat	10%
Disagree strongly	11%

Base: An aggregate of respondents from 2013 participating LDCs



Most residential energy use, most of the time, is invisible to the user. Most people have only a vague idea of how much energy they are using for different purposes and what sort of difference they could make by changing day-to-day behaviour or investing in efficiency measures. Feedback is important so that energy usage becomes visible, thereby, creating more understanding and ultimately easier to exercise control.

When it comes to energy, people tend to overestimate the amount of energy used by devices that are "visible" to them and underestimate the amount of energy used by devices that are "not visible" to them. SMART metering is also a key element of SMART grid technology. This year's survey probed around the concept of SMART grid, its importance and support towards working with neighbouring utilities.

The survey data indicates that customer awareness and understanding of the benefits that can be derived from SMART grid technologies are still in an early stage. For the most part respondents were mostly unfamiliar or uninformed.

Level of knowledge about the SMART Grid	Ontario LDCs
I have a fairly good understanding of what it is and how it might benefit homes and businesses	7%
I have a basic understanding of what it is and how it might work	17%
I've heard of the term, but don't know much about it	33%
I have not heard of the term	42%
Don't know	1%

Base: An aggregate of respondents from 2013 participating LDCs

Next respondents were asked what degree of importance they attached to their local hydro utility in pursuing the implementation of the SMART Grid and its associated technologies.

The SMART Insight from this poll is: even though more than half the respondents did not know much about the SMART Grid, 53% felt it was very or somewhat important to pursue its implementation and 75% responded that they were very or somewhat supportive of their local utility working with neighbouring utilities to get the most value out of the SMART Grid.

Importance of pursuing implementation of the SMART Grid	
	Ontario LDCs
Very important	23%
Somewhat important	30%
Neither important or unimportant	9%
Somewhat unimportant	5%
Unimportant	10%
Don't know	23%

Base: An aggregate of respondents from 2013 participating LDCs

Support towards working with neighbouring utilities on SMART Grid initiatives		
	Ontario LDCs	
Very supportive	38%	
Somewhat supportive	37%	
Neither supportive or unsupportive	4%	
Somewhat unsupportive	2%	
Unsupportive	6%	
Don't know	12%	0 %

Base: An aggregate of respondents from 2013 participating LDCs

Energy Conservation & Efficiency

Improving energy efficiency does not mean that citizens have to give up or forgo activities to save energy, that is, "turn off the lights and put on another sweater". Rather, new technologies and more effective behaviour will actually allow citizens to do more, improving their living conditions rather than reducing their comfort.

Reducing the amount of energy we use by choosing energy-efficient appliances and services, and ensuring we do not waste energy can make a big difference. It is possible for residents to cut energy use without compromising on performance, through changes in customer behaviour and by investing in more efficient energy technologies – effectively doing more with less.
This makes sense both for society as a whole and for businesses, individuals and families. Less energy use means lower energy bills. People simply need to be aware of their energy use.

Energy efficiency can be broken down into two areas:

1) better use of energy through improved energy-efficient technologies; and

2) energy saving through changes in customer awareness and behaviour.

Energy efficiency has been seen as primarily about technologies: using the best technology to consume less energy. Examples include changing a household furnace or air condition unit for one that consumes one third less energy, using low-energy light bulbs and avoiding keeping appliances in 'standby' mode. Respondents were asked what they have done or will do to conserve energy.

Efforts to conserve energy

Ontario LDCs	Yes	No	Already Done	Don't Know
Install energy-efficient light bulbs or lighting equipment	20%	10%	69%	1%
Install timers on lights or equipment	15%	49%	35%	2%
Shift use of electricity to lower cost periods	21%	19%	57%	3%
Install window blinds or awnings	15%	26%	58%	1%
Install a programmable thermostat	15%	20%	63%	2%
Have an energy expert conduct an energy audit	9%	70%	18%	3%
Removing old refrigerator or freezer for free	14%	45%	37%	4%
Join the peaksaverPLUS™ program	18%	48%	21%	13%
Replacing furnace with a high efficiency model	13%	36%	48%	3%
Replacing air-conditioner with a high efficiency model	16%	39%	41%	4%
Use a coupon to purchase qualified energy saving products	33%	42%	21%	4%

Base: An aggregate of respondents from 2013 participating LDCs / 90% of total respondents from the local utility

New technologies will have little effect if users cannot be convinced to use them. Changing customer behaviour has to be driven by increasing awareness of the benefits of energy saving, both for the individual and for society. Awareness of the energy that we use as individuals, families, households or organizations is very important – as is the impact that can be made by not wasting energy – both individually and collectively.

Behaviour is one of the parameters with a direct relation to individual energy consumption. Individual behaviour in energy use is determined by a number of factors, the most important of which are attitude, income and energy pricing. Less directly related are energy policy (including taxation) and technology availability as these relate to pricing and income respectively. However education can influence attitude in order to change behaviour; it can also inform individuals about energy policy and technology which feeds into behavioural change.

SMART Feedback from participants shows, predictably, the most frequently mentioned barrier to energy conservation was upfront financial costs. Not having the upfront funds limits the household's ability to invest in new appliances and to make other energy efficiency retrofits.

One participant noted that, even with programs that provide free appliance disposal, "if you get rid of your old fridge, you don't pay for disposal, but you need money for the cost of the new appliance". Likewise, another respondent commented that limited upfront funds "affect all households - but are particularly strong for low income households where there is no money to invest in retrofits."

Another barrier to conservation described by the survey respondents was awareness of programs and issues related to energy conservation. Generally speaking, the respondents felt that often lower-income and senior-occupied households did not have access to sufficient information that would allow them to reduce or to shift electricity usage. The respondents noted that although the person may have intentions of wanting to do the right thing, they are not sure or do not know exactly what the right thing to do is.

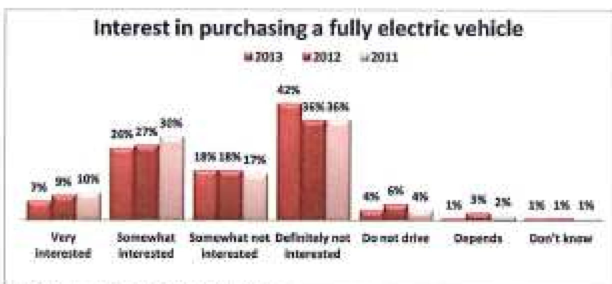
What are the 1 or 2 barriers to energy conservation experienced by Ontarians?	
	Ontario
Cost involved in making equipment/appliance changes	21%
Lifestyle changes / inconvenient	11%
Lack of interest or personal responsibility	8%
Lack of knowledge	7%
Waiting for better technology / Greener options	6%
Lack of information / confusion as to the "right" thing to do	5%
Not enough incentives	4%
Have an issue with Government policies	3%
None	12%
Don't know	29%

Base: total respondents from 2013 Ontario Benchmark survey

Purchasing an Electric Vehicle

A clear majority (60%) of car drivers are strongly not in favour of electric vehicles replacing conventional vehicles at this time. There is, however a significant minority (34%) who do favour such a development. None-the-less the EV is having an impact on travel and its influence is set to increase.

An income breakdown of the "positive support" data shows the strength of opinion in the higher income ranges. 45% of respondents in the $40k-$70k income range and 43% of those making $70K or more are in favour of EVs replacing conventional vehicles over time, and less than one quarter (22%) of wage earners in the under $40k category. Looking at age demographics, 22% of older respondents (55+) versus 47% of respondents aged 35-54 are in favour of EVs replacing conventional cars. 43% of those aged 18-34 are receptive to the idea of purchasing an electric vehicle.



Base: total respondents from 2013 Ontario Benchmark survey

When asked how long it would be before they would consider an EV as an option for their next car purchase, only 1 in 10 (11%) would consider an EV within the next 24 months.

Interest in purchasing a fully electric vehicle

	Income <$40K	Income $40K<$70K	Income $70K +	Age 18-34	Age 35-54	Age 55+
Very interested	4%	10%	11%	14%	12%	3%
Somewhat interested	18%	35%	32%	29%	35%	19%
Somewhat not interested	17%	17%	21%	24%	21%	16%
Definitely not interested	46%	35%	34%	33%	28%	53%
Don't know	1%	0%	2%	0%	2%	1%

Base: total respondents from 2013 Ontario Benchmark survey

Length of time before purchasing a fully electric vehicle

	Ontario
Immediately to next 6 months	1%
7 to 12 months	2%
13 to 24 months	8%
Over 24 months	84%
Depends	1%
Don't know	3%

Base: total respondents from 2013 Ontario Benchmark survey

E-care and E-billing

For any service provider including electric utilities, using the Internet for online customer care and electronic billing involves a number of interrelated requirements, including a customer's ability to:

- receive and pay bills on the internet,
- sign up for and change their services using the internet,
- find answers to their questions online about their accounts, i.e. statements, payments, balances
- learn about products, services and topics, i.e., green energy, electricity pricing, etc.

Do you have access to the internet?

	Ontario LDCs	CHEC
Yes	86%	83%
No	14%	17%

Base: An aggregate of respondents from 2013 participating LDCs / 90% of total respondents from the local utility

We asked respondents who were currently connected or had access to the internet if they in fact visited their local utility website. Out of all the respondents who had internet access, only 14% claim that they had actually been to their utility's website.

Over the past six months have you accessed your local utility website?		
	Ontario LDCs	CHEC
Yes	27%	14%
No	72%	86%

Base: An aggregate of respondents from 2013 participating LDCs / 90% of total respondents from the local utility

Does the average household customer feel comfortable enough with internet technology to believe it is the best place to get customer care or to receive and pay their bills?

Moving customer care and billing to the internet raises a number of questions and presents new opportunities to the utility industry.

- Is online billing and customer care a differentiator for utility providers?
- Can e-bills be used to improve customer loyalty by attracting customers to their website on a regular basis and thereby exposing customers to additional information, news, and education?
- Does the internet provide an environment where the most commonly asked general questions about a customer's hydro bill be highlighted or linked directly to the customer's bill?
- Can e-bills follow a cycle time that is customer driven? That is, could the customer determine the day in the billing cycle for the e-bill to be produced?

Likelihood of using the internet for future customer care needs for things such as:		
Top 2 Boxes: 'very + somewhat likely'	Ontario LDCs	CHEC
Setting up a new account	39%	29%
Arranging a move	47%	39%
Accessing information about your bill	59%	47%
Accessing information about your electricity usage	58%	49%
Accessing energy saving tips and advice	52%	43%
Learning more about SMART meters	49%	43%
Registering a complaint	43%	32%
Registering a compliment	48%	41%
Accessing information about Time Of Use rates	59%	49%
Maintaining information about your account or preferences	56%	46%
Paying your bill through the utility's website	35%	27%
Paying your bill using smart phone applications	23%	19%
Getting information about power outages	47%	41%

Base: An aggregate of respondents from 2013 participating LDCs / 90% of total respondents from the local utility

Ideally, utilities want customers to embrace e-billing and other electronic services; however, a hindrance on the most basic level will discourage customers from considering additional online services, i.e. accessing SMART meter data. The goal is to inform customers of their electricity usage, and make them aware of the potential to conserve electricity.

Accessed SMART meter information from the utility's website	Ontario LDCs	CHEC
Yes	8%	4%
No	91%	95%

Base: An aggregate of respondents from 2013 participating LDCs / 90% of total respondents from the local utility

What utilities don't want to do is force their customers to contend with a time-consuming, labour-intense process. Instead, make it easy, quick and secure. A positive online experience will most likely lead to a better online relationship with customers that will grow over time. Inconsistent user experiences are harmful to customer confidence.

The respondents, who did access their SMART meter information, claimed they found it to be easy ('very + somewhat') to access their SMART meter information.

Ease of accessing SMART meter information on the utility's website	Ontario LDCs	CHEC
Top 2 Boxes: 'very + somewhat easy'	90%	88%

Base: An aggregate of respondents from 2013 participating LDCs / 90% of total respondents from the local utility

Respondents were asked about the likelihood of accessing SMART meter data on the website in future.

Likelihood of accessing SMART meter information on the utility's website in future	Ontario LDCs	CHEC
Top 2 Boxes: 'very + somewhat likely'	49%	42%
Bottom 2 Boxes: 'somewhat + very unlikely'	50%	58%

Base: An aggregate of respondents from 2013 participating LDCs / 90% of total respondents from the local utility

The banking industry is one industry that has entered the online environment with consumers earlier than most industries; and therefore, many lessons can be learned from that industry for utility providers, including security, FAQs, prompt e-mail response, online bill history, and mistakes to avoid.

In order to convert traditional billing and payment customers to a paperless, automated solution, utilities need to understand the reasons behind customers' reservations, such as:

- process is not user-friendly leading to a poor customer experience
- online registration is or could be a hassle
- the extra work of keeping track, downloading etc. in a time pressed society
- password fatigue for customers who just don't want to manage another log-in credential
- apprehension that no longer receiving a paper bill could increase the likelihood that they'll inadvertently miss a bill and/or payment
- unease that payment information will not be secure and could be easily hacked.

Consumers will eventually adopt electronic billing and online customer care as many industries begin providing consumer bills online, and critical mass is reached. However, customers still want to have the choice of receiving customer care from a live person. Even after they start using online technology, customers still want to be able to receive hard copies of their bills as a backup.

Using the Internet for billing

	Ontario LDCs	CHEC
I am already receiving my hydro bill electronically	10%	4%
I use on-line banking and will definitely be requesting that my bill be sent electronically	11%	11%
I use on-line banking but prefer to have paper statements	30%	35%
I prefer to have the paper copy of my bills	23%	28%
I don't use on-line banking	17%	22%

Base: An aggregate of respondents from 2013 participating LDCs / 90% of total respondents from the local utility

Because utilities serve a diverse demographic that includes households, businesses, all income levels, and people from all walks of life, understanding customers' concerns, needs and comfort levels will go a long way to ensuring that the solution is one that they will actually use. For example, interactive voice response (IVR) system with specific-language call flows, young working commuters might be more inclined to use mobile bill-pay, or those customers (e.g., senior citizens) who might not be as adept or comfortable with technology might prefer the ability to pay over the phone or in-person.

Understanding customer profiles will enable utilities to provide the right bill-pay options for them; thereby increasing usability rates— and, the perception that they adapt well to changes in customer expectations.

Using the Internet for billing

Ontario LDCs	18-34	55+
I am already receiving my hydro bill electronically	19%	8%
I use on-line banking and will definitely be requesting that my bill be sent electronically	20%	7%
I use on-line banking but prefer to have paper statements	36%	24%
I prefer to have the paper copy of my bills	9%	29%
I don't use on-line banking	5%	24%
Don't know	10%	8%

Base: An aggregate of respondents from 2013 participating LDCs

If utility companies ensure that the electronic billing solutions they offer customers are easy to use, convenient, feature-rich, comprehensive and secure, adoption rates will surely increase.

Likelihood of the following to encourage customers to go paperless for billing purposes

Top 2 Boxes: 'very + somewhat likely'	Ontario LDCs	CHEC
Providing a one-time financial incentive to switch	53%	44%
Being entered into a special draw for customers who make the switch	42%	35%
Learning more about the benefits to going green with paperless billing	46%	37%
A better understanding of the convenience of paperless billing	45%	37%

Base: An aggregate of respondents from 2013 participating LDCs / 80% of total respondents from the local utility

Customers are afraid if they don't receive a paper bill in the mail each month, they are going to forget to make a payment as well as, incur penalties and late fees or even harm their credit score. By proactively delivering information to customers, by phone, text, and email, customers will remain informed and in control of their billing and account status and be more likely to use additional online services. Also, giving customers online access to the prior 18 to 24 months of billing statements will alleviate concerns over losing a bill or needing old statements. Ensuring that a switch to online processes does not change anything for a customer is key; the idea is to make sure customers are provided with everything they have always had, plus a lot more.

Social Media

Social media is evolving at an incredible pace. Importantly, it seems to represent a shift in how people discover, read and share news, information and content. As customers increasingly turn to social channels to seek information and advice and to express opinions, there is no question that organizations must engage with those channels to deliver appropriate customer care and ensure positive experiences. Respondents of this year's survey were asked *"how likely they would use social media as a resource for energy efficiency tips or to help manage your electricity use"*...

Likelihood of using Social Media to gather information

	CHEC	Ontario LDCs	Ontario LDCs Age Group: 18-34	Ontario LDCs Age Group: 55+
Very likely	4%	6%	10%	3%
Somewhat likely	7%	11%	17%	6%
Not likely	22%	20%	24%	17%
Not likely at all	64%	61%	48%	68%
Don't have social media account	2%	2%	0%	4%
Don't know	0%	1%	0%	1%

Base: An aggregate of respondents from 2013 participating LDCs / 80% of total respondents from the local utility

What do customers think about electricity costs?

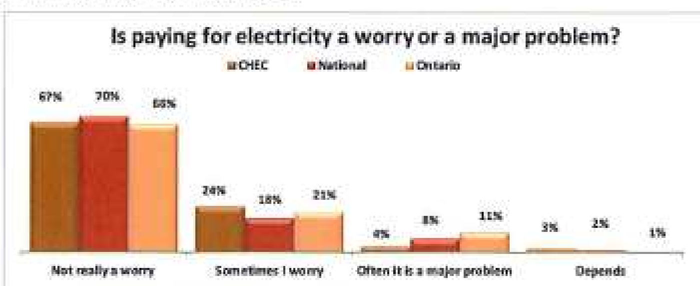
Today electric utilities are facing steadily, increasing costs to generate and deliver electricity. Utilities are building transmission lines, installing new equipment and fixing up power plants. While LDC's make continuous efficiency improvements and are working with regulators to contain costs and to keep electricity prices as low as possible, the fact is that rising electricity costs are becoming inevitable.

At a time when income growth seems to be stagnating, electricity is consuming a greater share of Canadians' after-tax income than at any time since the mid 1990's. Higher costs are being driven by both higher prices per kilowatt hour and greater electricity use at home, in roughly equal measure. While modern electronics and appliances require less electricity than older models, i.e. a new refrigerator runs on half the electricity of a model from the 1990's, houses have become bigger, which entail more air-conditioning and more electronics than before.

Next I am going to read a number of statements people might use about paying for their electricity. Which one comes closest to your own feelings, even if none is exactly right? Paying for electricity is not really a worry, Sometimes I worry about finding the money to pay for electricity, or Paying for electricity is often a major problem?

Is paying for electricity a worry or a major problem?				
	Not a worry	Sometimes	Often	Depends
CHEC				
2013	67%	24%	4%	3%
2012	-	-	-	-
2011	-	-	-	-
2010	-	-	-	-

Base: total respondents / (-) not a participant of the survey year



Base: total respondents

There are certain kinds of costs that hit fixed-income (those on disability income) and low-income people the most, and one of those things is energy costs, which are not discretionary. Ontario is one of several provinces to install "SMART" electricity meters on households. They promote better resource use by billing customers extra for energy consumed during peak daytime hours, however in order to benefit from TOU a behaviour change in consumption must take place.

Is paying for electricity a worry or a major problem?				
	Not a worry	Sometimes	Often	Depends
CHEC				
<$40,000	54%	35%	7%	4%
$40<$70,000	61%	32%	3%	3%
$70,000+	80%	13%	3%	3%

Base: total respondents

Customers have a right to expect more than the mere delivery of electricity. They have the right to expect efficiency, competence and value for money. Utilities seeking to become more customer-centric must go beyond the transactional relationship of customer pays a price and receives electricity. Becoming customer-centric involves offering customers a value proposition; a complete package, filled with lots of human-friendly usability elements, peace of mind, and top-notch customer service.

Is paying for electricity a worry or a major problem?				
	Not a worry	Sometimes	Often	Depends
Ontario				
2013	66%	21%	11%	1%
2012	59%	27%	11%	2%
2011	52%	31%	13%	3%
2010	67%	23%	8%	2%
National				
2013	70%	18%	8%	2%
2012	67%	22%	8%	2%
2011	63%	25%	8%	2%
2010	71%	20%	8%	1%

Base: 2013 Ontario and National benchmark surveys

What do small commercial customers think?

Residential and small business customers create the bulk of a utility's service transactions every day—and account for more than half of the energy consumed — understanding their needs and expectations is becoming more important than ever before.

Small Commercial Customer (General Service < 50kW Demand)

A small commercial customer is defined by the OEB as a non-residential customer in a less than 50 KW demand rate class. These customers are similar to the residential customer in that their bill does not have a demand component to it and their charges are based upon KWH of consumption. Most of these customers would occupy small storefront locations or offices

In the 15 years that UtilityPULSE has undertaken electric utility satisfaction surveys, the data has mostly supported that the small business owner behaves much in the same way as the residential customer. While there are typically more similarities between small commercial and residential accounts, there are some fundamental differences in these customer classed segments. This year's data shows a difference in satisfaction levels for customer service; commercial customers responded more favourably than residential. On the subject of bills and outages, residential respondents reported more outage problems and fewer billing problems than commercial customers.

Deposit requirements, monthly energy bills (and, therefore, energy usage), power quality, and reliability all directly impact a small business's financial situation. Unlike residential customers who tend to describe the cost of power interruptions in terms of a "inconvenience", commercial (and industrial) customers associate power interruptions with the cost of lost business, i.e., a loss in production is a loss in profits.

Likewise, based on the requirement of electricity to sustain business operations, there exists a difference in actual levels of demand response. For instance, small business and commercial users are unlikely to choose to decrease their electricity consumption if it is incompatible with efficient management of their business processes or threatens contracted deliveries to their primary product markets. In some cases, electricity consumption is a relatively small proportion of total input and operating costs, which substantially reduces the financial incentive for shutting down production during on peak pricing.

The tables associated with this report will contain Ontario LDC specific information as it relates to residential and commercial customers. Recognizing that smaller data samples are susceptible to greater data swings, for most LDCs there would be 60 or 90 responses from small commercial customers. We have compiled the following based on a group composite of all of our 2013 discussions with small commercial and residential customers.

Satisfaction: Pre & Post		
Satisfaction (Top 2 Boxes: 'very + somewhat satisfied')	Residential	Commercial
Initially	92%	93%
End of interview	93%	94%

Base: total respondents from the full 2013 database

As it relates to the six attributes associated with customer service:

Very or fairly satisfied with...	Residential	Commercial
The time it took to contact someone	79%	83%
The time it took someone to deal with your problem	76%	81%
The helpfulness of the staff who dealt with your problem	78%	85%
The knowledge of the staff who dealt with your problem	79%	85%
The level of courtesy of the staff who dealt with your problem	86%	92%
The quality of information provided by the staff member	76%	83%

Base: total respondents from the full 2013 database

Overall Commerical respondents were more satisfied with customer service than Residential respondents

Overall satisfaction with most recent experience		
	Residential	Commercial
Top 2 Boxes: 'very + somewhat satisfied'	78%	81%
Bottom 2 Boxes: 'somewhat + very dissatisfied'	20%	17%

Base: total respondents from the full 2013 database

Comparisons between Residential and Commercial		
Loyalty Groups	Residential	Commercial
Secure	30%	29%
Still Favourable	13%	14%
Indifferent	51%	50%
At risk	6%	7%

Base: total respondents from the full 2013 database

Loyalty Model Factors	Residential	Commercial
Very/somewhat satisfied	92%	93%
Definitely/probably would continue	84%	83%
Definitely/probably would recommend	78%	79%

Base: total respondents from the full 2013 database

Outages & Bill problems	Residential	Commercial
Respondents with outage problems	29%	23%
Respondents with billing problems	9%	13%

Base: total respondents from the full 2013 database

Attempts to contact local utility...	Residential	Commercial
Respondents with outage problems	18%	37%
Respondents with billing problems	51%	69%

Base: total respondents from the full 2013 database

Important attributes which describe operational effectiveness	Residential	Commercial
Provides consistent, reliable energy	96%	95%
Delivers on its service commitments to customers	89%	89%
Accurate billing	86%	88%
Quickly handles outages and restores power	87%	85%
Makes electrical safety a top priority	55%	66%
Uses responsible business practices	67%	75%
Is efficient at managing the hydro-electric system	72%	71%
Is a company that is 'easy to do business with'	85%	89%
Operates a cost effective hydro-electric system	61%	61%

Base: total respondents with an opinion from the full 2013 database

Important attributes which shape perceptions about corporate image	Residential	Commercial
Is a respected company in the community	85%	86%
Maintains high standards of business ethics	70%	76%
A leader in promoting energy conservation	74%	70%
Keeps its promises to customers and the community	72%	73%
Beyond creating jobs and paying taxes, is socially responsible	66%	65%
Is a trusted and trustworthy company	85%	87%
Adapts well to changes in customer expectations	62%	64%
Overall the utility provides excellent quality services	91%	92%

Base: total respondents with an opinion from the full 2013 database

Important attributes which shape perceptions about service quality and value	Residential	Commercial
Is pro-active in communicating changes and issues which may affect customers	79%	78%
Provides good value for money	69%	69%
Customer-focused and treats customers as if they're valued	75%	77%
Deals professionally with customers' problems	72%	82%
Quickly deals with issues that affect customers	71%	76%
Provides information and tools to help manage electricity consumption	82%	78%
Works with customers to keep their electricity costs affordable	61%	57%
The cost of electricity is reasonable when compared to other utilities	56%	53%

Base: total respondents with an opinion from the full 2013 database

Is paying for electricity a worry or a major problem?	Residential	Commercial
Not really a worry	70%	71%
Sometimes I worry	20%	19%
Often it is a major problem	6%	6%
Depends	3%	2%

Base: total respondents

Method

The findings in this report are based on telephone interviews conducted for Simul Corp. by Consential between April 10 - April 23, 2013, with 632 respondents who pay or look after the electricity bills from a list of residential and small and medium-sized business customers supplied by CHEC.

The sample of phone numbers chosen was drawn randomly to insure that each business or residential phone number on the list had an equal chance of being included in the poll.

The sample was stratified so that 85% of the interviews were conducted with residential customers and 15% with commercial customers.

In sampling theory, in 19 cases out of 20 (95% of polls in other words), the results based on a random sample of 632 residential and commercial customers will differ by no more than ±3.90 percentage points where opinion is evenly split.

This means you can be 95% certain that the survey results do not vary by more than 3.90 percentage points in either direction from results that would have been obtained by interviewing all CHEC residential and small and medium-sized commercial customers if the ratio of residential to commercial customers is 85%:15%.

The margin of error for the sub samples is larger. To see the error margin for subgroups use the calculator at http://www.surveysystem.com/sscalc.htm.

Interviewers reached 1,652 households and businesses from the customer list supplied by CHEC. The 632 who completed the interview represent a 38% response rate.

The findings for the Simul/UtilityPULSE National Benchmark of Electric Utility Customers are based on telephone interviews conducted March 13 through March 26, 2013, with adults throughout the country who are responsible for paying electric utility bills. The ratio of 85% residential customers and 15% small and medium-sized business customers in the National study reflects the ratios used in the local community surveys. The margin of error in the National poll is ±2.7 percentage points at the 95% confidence level.

For the National study, the sample of phone numbers chosen was drawn by recognized probability sampling methods to insure that each region of the country was represented in proportion to its population and by a method that gave all residential telephone numbers, both listed and unlisted, an equal chance of being included in the poll.

The data were weighted in each region of the country to match the regional shares of the population.

The margin of error refers only to sampling error; other non-random forms of error may be present. Even in true random samples, precision can be compromised by other factors, such as the wording of questions or the order in which questions were asked.

Random samples of any size have some degree of precision. A larger sample is not always better than a smaller sample. The important rule in sampling is not how many respondents are selected but how they are selected. A reliable sample selects poll respondents randomly or in a manner that insures that everyone in the population being surveyed has an equal chance of being selected.

How can a sample of only several hundred truly reflect the opinions of thousands or millions of electricity customers within a few percentage points?

Measures of sample reliability are derived from the science of statistics. At the root of statistical reliability is probability, the odds of obtaining a particular outcome by chance alone. For example, the chances of having a coin come up heads in a single toss are 50%. A head is one of only two possible outcomes.

The chance of getting two heads in two coin tosses is less because two heads are only one of four possible outcomes: a head/head, head/tail, tail/head and tail/tail.

But as the number of coin tosses increases, it becomes increasingly more likely to get outcomes that are either close to or exactly half heads and half tails because there are more ways to get such outcomes. Sample survey reliability works the same way but on a much larger scale.

As in coin tosses, the most likely sample outcome is the true percentage of whatever we are measuring across the total customer base or population surveyed. Next most likely are outcomes very close to this true percentage. A statement of potential margin of error or sample precision reflects this.

Some pages in the computer tables also show the standard deviation (S.D.) and the standard error of the estimate (S.E.) for the findings. The standard deviation embraces the range where 68% (or approximately two-thirds) of the respondents would fall if the distribution of answers were a normal bell-shaped curve.

The spread of responses is a way of showing how much the result deviates from the "standard mean" or average. In the

CHEC data on corporate image, Simul converted the answers to a point scale with 4 meaning agree strongly, 3 meaning agree somewhat and so on (see in the computer tables).

For example, the mean score is 3.63 for providing consistent, reliable energy. The average is 2.93 for working with customers to keep their energy costs affordable.

For reliable energy the standard deviation is 0.57. For affordable energy the S.D. is 0.82. These findings mean there is a wider range of opinion – meaning less consensus – about whether CHEC works with customers to keep their energy costs affordable than about whether CHEC energy supplies are reliable.

Beneath the S.D. in the tables is the standard error of the estimate. The S.E. is a measure of confidence or reliability, roughly equivalent to the error margin cited for sample sizes. The S.E. measures how far off the sample's results are from the standard deviation. The smaller the S.E., the greater the reliability of the data.

In other words, a low S.E. indicates that the answers given by respondents in a certain group (such as residential bill payers or women) do not differ much from the probable spread of the answers "predicted" in sampling and probability theory.

Certain questions pertaining to conservation and conservation efforts used an aggregate data approach whereby similar data sets were accumulated to form a larger sample size establishing a higher confidence interval, forecasting value and modeling data.

In these instances, all of the sub-datasets from the entire UtilityPULSE database for 2013 were concatenated in order to use the average of all the control samples for comparison. The cumulated population base for these questions was in excess of 6,000.

At a 95% confidence level the margin of error is ±1.23 and at a 99% confidence level the margin of error would be ±1.62. So the aggregate strategy has given a very good population sample size which better, or more accurately, reflects the true feelings and beliefs of the population as a whole.

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4.0 - VECC- 22

Reference: Exhibit 4, Tab 2, Schedule 1, pg.8

a) Please explain why meter reading costs have increased since 2009 and notwithstanding the introduction of smart meters?

b) Please compare and contrast the $85k spent on meter reading in 2009 with the $192K forecast spending in 2013.

c) Please provide the cost of the last full year of contract meter reading services (i.e. those services discontinued in 2012).

Response

a) Please refer to 4.0-Staff-24
b) Please refer to 4.0-Staff-24
c) The last full year of contract metering services was in 2010. Please see the chart below, which indicates an annual contract metering expense of about $90k per year.

	Forecast December 2013	December 2012	December 2011	December 2010	December 2009
Billing and collecting:					
5310-0000-00 Meter Reading Expense	12,000	28,287	46,175	89,108	87,467
5310-0000-04 Meter Read - Smart Meter Operations	180,000	209,440			
5315-0000-04 Cust Billing - Smart Meter Operations	60,000	114,604			
	252,000	352,331	46,175	89,108	87,467

4.0 - VECC- 23

Reference: Exhibit 4, Tab 2, Schedule 1, pg.8

a) Please provide a breakdown of Account 5315 (Customer Billing), which compares and explains the difference between the 2009 costs of $489k and the 2013 forecast costs of $534k.

b) Does COLLUS expect to continue to prepare its customer bills separately from PowerStream under the new joint ownership arrangements?

Response

a)

		Forecast					OEB Approved
		December 2013	December 2012	December 2011	December 2010	December 2009	2009
	5315-0000-00 Customer Billing	372,000	370,657	386,889	491,705	492,772	
NEW	5315-0000-04 Cust Billing - Smart Meter Operations	60,000	114,604				
	5315-0001-00 Customer Billing -Retailer Exp	7,200	10,720	1,362	15		
	5315-0002-00 EBT& EMERA Expense	79,476	77,664	80,803	87,803	84,567	
	5315-0003-00 Customer Final Bill Refunds	-	(593)	(340)	1,185	48	
	5315-0004-00 Bank Charges (previously in 5315-0000-00)	15,600	14,267				
		534,276	587,319	468,714	580,708	577,387	489,093
	Variance to 2009 Approved	45,183.00					
	Less: New extra smart meter operations expenses	(60,000.00)					
	Decrease in customer billing exp with Smart Meters removed	(14,817.00)					

b) Collus PowerStream presently continues to prepare its customer bills separately. However, joint effort is on-going to determine areas where we can share resources. Such discussion is still in the preliminary stages. Considering Collus PowerStream is locked into contracts for software and support and PowerStream is currently working on the implementation of their own new billing software system, the outlook is a long range goal at this point.

4.0 - VECC- 24

Reference: Exhibit 4, Tab 2, Schedule 2, pg. 2

a) Did COLLUS or PowerStream Inc. prepare any analysis in respect to the potential cost savings that might be had as part of the acquisition transaction? If yes, please provide that analysis.

Response

a) Intuitively, one would expect potential savings and the adoption of best practices with a transaction such as our new relationship with PowerStream. Collus Power did not however prepare a detailed analysis of the savings since they will only be truly known with time. We have no knowledge if PowerStream completed an analysis.

4.0 - VECC- 25

Reference: Exhibit 4, Tab 1, Schedule 2

a) Please provide association fees paid to the EDA for each of the years 2009 through 2013 (forecast).

b) Separately provide and describe the cost of all other association memberships.

Response

a) The association fees paid (excluding tax) to the EDA for the years 2009 through to 2013 (actual) are as follows:

2009 - $25,000
2010 - $26,100
2011 - $26,950
2012 - $28,450
2013 - $29,800

b) Below we have separately provided with a description all other major association memberships. The costs represent the 2013 annual membership fees only.

Associations Name	Description	Cost
Cornerstone Hydro Electric Concepts Inc. (CHEC)	An association of local distribution companies (LDCs) modeled after a cooperative to combine resources and competencies to best meet the requirements of the changing electrical industry and provide a high standard of locally supplied customer service.	$ 45,000
Electrical Safety Authority (ESA)	Established with the mandate to enhance public electrical safety in Ontario. ESA is a delegated administrative authority, an independent, not-for-profit corporation acting on behalf of the Government of Ontario with specific responsibilities for electrical safety.	7,012
Utility Standards Forum (UCF)	Provides members with a consistent, cost effective and ESA approved set of standards; a key component to the membership's operations. USF also provides the mechanism for maintaining a strong member and industry network, with focus on creating best practices through collaboration and reduced duplication of efforts when meeting regulatory requirements.	8,750

Utility Collaborative Service Inc. (UCS)	An Ontario based organization of provincial Local Distribution Companies (LDCs) created to provide members with reliable cost-competitive long term software and service solutions in an increasingly complex and resource intensive marketplace. The members support and work co-operatively on standardization of their systems leading to major cost savings for each other. The LDCs recognized that by working together they can negotiate preferential agreements with vendors and can see cost savings through shared resources.	-

4.0 - VECC- 26

Reference: Exhibit 4, Tab 1, Schedule 2

a) Please provide the annual membership fees for each of CHEC, UCS and USF.

b) Does COLLUS expect to drop or combine membership in any of these organizations as part of the PowerStream group?

Response

a) The annual membership fees for CHEC and USF are provided in the table seen in 4.0 – VECC – 25 b). There is no annual membership fee for UCS. The fees paid to UCS are monthly based on services utilized.

b) The board of directors is currently investigating the costs and benefits in all organizations we have memberships with. Some of these memberships have termination clauses that need to be considered.

4.0 - VECC- 27

Reference: Exhibit 4, Tab 2, Schedule 1 / Schedule 2, pg. 3

a) On page 5 of E4/T2/S1 COLLUS notes that ongoing Smart Meter maintenance costs are forecasted at $240K with is a $150K increase from 2009 approved levels. At page 3 of Schedule 2 it shows $240k as the smart meter cost driver. Please clarify if the net incremental costs since 2009 for smart meters are $150k or $240k.

Response

a) The net incremental costs for just smart meters related to meter reading and customer billing operations is $240,000. The decrease in contract manual reading expense is $73,000. The net difference is $167,000. See chart below for clarification.

		Forecast *December 2013*	OEB Approved *December 2009*	Variance	
	5310-0000-00 Meter Reading Expense	12,000.00	85,000.00	(73,000.00)	
NEW	5310-0000-04 Meter Read - Smart Meter Operations	180,000.00	0.00	180,000.00	
NEW	5315-0000-04 Cust Billing - Smart Meter Operations	60,000.00	0.00	60,000.00	240,000.00
		252,000.00	85,000.00	167,000.00	

4.0 - VECC- 28

Reference: Exhibit 4, Tab 2, Schedule 2

a) Please provide incremental costs incurred in 2013 that were for regulatory responsibilities not incurred in 2009 (for example, Net CDM, Green Energy, Asset Management etc.). Please also provide the incremental FTEs since 2009 that have been hired to meet these incremental regulatory requirements.

Response

a) Exhibit 4, Tab 2, Schedule 2 does not exist.

As far as CDM in 2013, PowerStream and Collus PowerStream have signed a contract and a new staff person was hired at PowerStream to handle our CDM. However, this comes out of the PAB funding and does not impact the revenue requirement.

We have not hired internally any FTEs since 2009 related to regulatory responsibilities. Our regulatory manager retired at the end of 2010 and his replacement overlapped for eight months before he left, but this was more for succession planning. Some of the retired regulatory manager's duties were reallocated to our SCADA operations person, specifically MicroFIT and the Green Energy Plan. The SCADA operations person had reduced work load from the water company and was able to perform these additional duties. We do not have accounting records that track such incremental costs.

Asset management requirements will begin in 2013, we plan to handle the extra responsibility with the staff already on hand. Additional software, training, and support costs will be required to have this system operational.

4.0 - VECC- 29

Reference: Exhibit 4, Tab 2, Schedule 4

a) Please provide the productivity offset and stretch factors that were used by the Board during the previous IRM period.

Response

a) As per Board letter dated March 10, 2010 Re: Board Determination of Stretch Factor Rankings for 2010 3rd Generation Incentive Regulation Applications (IRM3) EB-2009-0392, Collus PowerStream was placed in Group 2, whose stretch factor was 0.4%.

   Collus PowerStream filed IRM3 EB-2009-0220, for 2010 rates, with a stretch factor of 0.4% and productivity offset of 0.72%.

   Collus PowerStream filed IRM3 EB-2010-0076, for 2011 rates, with a stretch factor of 0.4% and productivity offset of 0.72%.

   Collus PowerStream filed IRM3 EB-2011-0164, for 2012 rates, with a stretch factor of 0.4% and productivity offset of 0.72%.

4.0 - VECC- 30

Reference: Exhibit 4, Tab 1, Schedule 4

a) Please provide the training and staff development budgets in each year 2009 through 2013.

Response

a) We have never maintained training and staff development budgets historically. However, in the finance department we started to track PD for 2013 in an attempt to carve out that portion of the accounting, billing, collecting, and customer service staff budget. This is an area every department should look to develop further, and we will target this as a goal.

4.0-VECC – 31

Reference: Exhibit 4, Tab 2, Schedule 4, pg.4

a) Please provide the total costs in 2012 that were related to the PowerStream transaction (e.g. audit and regulatory costs) including any buyout or early retirements (please show internal and external costs separately).

Response

a) Please refer to 4-Energy Probe-26 & 29

4.0-VECC – 32

Reference: Exhibit 4, Tab 2, Schedule 4, pg.4

a) Please provide a list of each of the positions for the 4.84 FTEs that have been added from 2009 actuals. Please provide the total amount of salary and benefits related to these FTEs.

Response

a) Reference: Exhibit 4, Tab 2, Schedule 4, pg.4 does not exist.

On Exhibit 4, Tab 1, Schedule 2, Pg.4 there is a table 1 entitled OM&A per Customer and FTE. This indicates the 2009 board approved FTE as 21.60 and the 2013 Test year as 22.92. This is a difference of 1.32 rather than 4.84.

Please also see 4.0-Staff-25 part b.

4.0-Staff-24

Ref: E4/T1/S1, p. 5 and E2/T3/S2, Asset Management Plan – Smart Meter Maintenance Costs and E4/T4/S1, Table 3 – Meter Reading Expenses

On page 5 of E4/T2/S1 Collus PowerStream notes that ongoing Smart Meter maintenance costs are forecasted at $240K with is a $150K increase from 2009 approved levels. On page 29 of the Asset Management Plan, Collus PowerStream describes a failure and replacement rate of 5.22% of the total population of installed smart meters.

Table 3 of E4/T4/S1 shows a meter reading expense of $192,000 in the 2013 test year, which is an increase of 126% over 2009 Board approved and a 316% increase over 2011actuls.

a) Please provide more information on the proposed ongoing Smart Meter maintenance cost.

b) Please elaborate if and when Collus PowerStream anticipates a decrease in the maintenance costs as Smart Meters are being replaced in response to the failure rate of the existing smart meter population.

c) Please explain if the Smart Meter maintenance cost is part of the increase in account 5310 - Meter Reading Expense. If not, please explain the increase in meter reading expenses.

d) Please state if Collus PowerStream has been able to realize any efficiency cost savings in meter reading costs due to the installation of smart meters. If not, please explain why not.

Response

a) The Ontario government introduced legislation on Nov. 3, 2005 to start the process of getting smart meters into every home and small business in the province by 2010. Collus PowerStream has complied with this mandate.

   In Collus PowerSteam's Smart Meter Application filed with the OEB on January 16, 2012 and approved in the June 21, 2012 decision and order EB 2012-0017, there were $252,000 annual on-going smart meter operation costs forecasted. The costs consist of the following $20,000 monthly amounts plus a $12,000 annual AMI security audit.

		Monthly	Annually
5310-0-4	Smart Meter Operations – Meter Reading	$15,000.00	$180,000.00
5315-0-4	Smart Meter Operations - Customer Billing	5,000.00	60,000.00
		$20,000.00	$240,000.00

These expenses result from the following smart meter operation requirements:

- Sensus Tower Gateway Base Station (TGB)
- Kinetiq/Savage Operational Data Storage (ODS)
- Point-to-Point Broadband
- Bell Wurldtech Sensus AMI security audit
- ITM AS2 License
- Web presentment
- Util-Assist Sync Operator
- ODS security audit
- Customer education
- DSC operator services

Communication, data integrity, IT security, along with computing system reliability, safety and maintainability, are critical attributes for smart meter implementation and operation. These smart meter expenses are a requirement to operate the system and provide overall risk management for the infrastructure.

For improved clarity E4/T2/S1 should state ongoing smart meter "<u>operation costs</u>" rather than "<u>maintenance costs</u>". These accounts are not related to the percentage failure and replacement rate.

b) Based on the current meter and radio firmware technology a decrease in the maintenance costs as a result of meter failures is not anticipated. Current "smart Meter" technology consists of a meter and communications technology and are more a computer than a meter. To date the majority of meter failures have occurred due to firmware or radio communications issues and this is not expected to change. The actual metrology portion is a small portion of a "smart Meter" and in Collus PowerStream's experience failure of this portion of the meter is rare.

c) Smart meter repairs and maintenance costs are not part of the increase in account 5310 – Meter Reading Expense. Costs for repairs and maintenance to smart meters are included in account 5175 Maintenance of Meters. Please see part d for reasons why smart meter reading expense has increased.

d) Collus PowerStream has not been able to realize any efficiency cost savings in meter reading costs due to the installation of smart meters. Meter Reading expenses under the old manual meters averaged about $90,000 between 2005 and 2008 before implementation of smart meters started. Our meter reading expense is forecasted for 2013 as $192,000, which is $180,000 annually for smart meters plus $12,000 for any required manual reads.

Significant increased operating costs have been realized with smart meters due to the complexity of the technology and data system. But, the long-term benefits of this technology and advancement are important to the future of the province's electrical infrastructure.

4.0-Staff-20

Ref: E4/T4/S1, pp. 1-4, Tables 1, 2, 3, and 5

Please provide year-to-date OM&A expenses at the same level of detail as tables 1 through 5.

Response

Table 1

	June 2013 YTD
Operation Expense	
5005-0000-00 Opr Supervisn & Engnring	111,211
5010-0000-00 Opr Load Dispatching/SCADA	34,113
5012-0000-00 Opr Stn Buildgs & Fixtures Exp	15,231
5020-0000-00 Opr OH Dist Lines/Fdr - Labour	28,987
5025-0000-00 Opr OH Dist Lines/Fdr - Expnse	17,646
5030-0000-00 Opr OH Subtrans Feeder	0
5035-0000-00 Opr OH Dist Transformers	13,777
5040-0000-00 Opr UG Dist Lines/Fdr - Labour	2,451
5045-0000-00 Opr UG Dist Lines/Fdr - Expnse	0
5055-0000-00 Opr UG Dist Transformers	8,083
5065-0000-00 Opr Meter Expense	501
5085-0000-00 Opr Misc Distribution Exp	19,217
5096-0000-00 Rent - Stores & Operations Centre	86,400
Total Operation Expense	337,617

Table 2

Maintenance Expense	
5105-0000-00 Mtce Supervision & Engineering	69,409
5110-0000-00 Mtce of Station Buildings	5,467
5114-0000-00 Mtce Substn Equipment	0
5120-0000-00 Mtce Poles, Towers & Fixtures	81,965
5125-0000-00 Mtce OH Conductor & Devices	150,674
5130-0000-00 Mtce of OH Services	72,977
5135-0000-00 Mtce OH Dist Right of Way	20,025
5150-0000-00 Mtce UG Conductor & Devices	54,814
5155-0000-00 Mtce of UG Services	100,348
5160-0000-00 Mtce Line Transformers	46,897
5175-0000-00 Mtce of Meters	131,070
5190-0000-00 Mtce W/Htr Controls-Labour	0
Total Maintenance Expense	733,646
Total Operation & Maintenance Expense	**1,071,265**

Table 3

	June 2013 YTD
Billing and collecting:	
5305-0000-00 Billing Supervision	37,400
5310-0000-00 Meter Reading Expense	1,340
5310-0000-04 Meter Read - Smart Meter Operations	75,231
5315-0000-00 Customer Billing	169,158
5315-0000-04 Cust Billing - Smart Meter Operations	16,744
5315-0001-00 Customer Billing -Retailer Exp	7,119
5315-0002-00 EBT& EMERA Expense	39,276
5315-0003-00 Customer Final Bill Refunds	0
5315-0004-00 Bank Charges	3,802
5320-0000-00 Collecting	51,577
5320-0001-00 Collecting - Insurance - Business Credit	13,293
5325-0000-00 Collecting Cash Over & Short	(54)
5335-0000-00 Bad Debt Expense	5,967
Total Billing & Collecting	420,853

Table 4

Community Relations	
5415-0000-00 Energy Conservation	0
5425-0000-00 Misc Cust Ser&Inform Expenses	70,805
Total Community Relations	70,805

Table 5

General & Administration:	
5605-0000-00 Executive Salaries & Expenses	320,396
5610-0000-00 Management Salaries & Expenses	
5615-0000-00 General Admin Salaries & Expenses	
5630-0000-00 Outside Services Employed	100,952
5635-0000-00 Property Insurance	14,444
5640-0000-00 Injuries and Damages	28,167
5655-0000-00 Regulatory Expenses	55,408
5660-0000-00 General Advertising Expenses	1,970
5665-0000-00 Miscellaneous General Expenses	45,425
5670-0000-00 Rent	21,600
5672-0000-00 Computer Lease Expense	10,896
5675-0000-00 Maintenance of General Plant	14,260
5680-0000-00 Electrical Safety Author Fees	3,557
5681-0000-00 OEB Special Purpose Charge Expense	0
6105-0000-00 Taxes Other Than Income Taxes	43
6205-0000-00 Donations & LEAP	13,319
Total General & Administration	630,437

4.0-Staff-23

Ref: E4/T4/S1, p.1 and E4/T4/S4, p. 7 – Operations Expenditures – Other Rent

On page 7 of E4/T4/S4, Collus PowerStream notes that Operations expenses have increased by $315,000 or 108% over the 2009 Board-approved levels. Board staff notes that on the summary table 1, E4/T4/S1, p. 1 Collus PowerStream has included a cost of $172,800 in account 5096 Other Rent and a $132,00 in account 5005 – Operation Supervision and Engineering.

a) Please provide a detailed explanation for the 90% or $62,610 increase in account 5005 Operation Supervision and Engineering in the 2013 test year over 2009 actuals.

b) Please explain the cost of $172,800 booked in account 5096 Other Rent in more detail.

Response

a) Operations Supervision and Engineering has increased due to succession planning hiring requirements. The superintendent retired in the spring of 2012. His replacement was filled internally and an operations assistant was added to help with the increasing workload of a larger system. The allocation of supervision and engineering expenditures also fluctuates based on the amounts that are allowable as direct capital costs, especially under more restrictive IFRS rules.

b) Previously rent was allocated to the burden for warehouse and garage. The burden would then be allocated to various operations and maintenance expenses or capital projects currently in progress. The costs were capitalized to the extent that materials were issued to, and vehicles and equipment were used on capital work orders.

   The capitalization policy has been modified to be IFRS compliant. Account 5096 is now being used for warehouse and garage rent and no longer posted to the burden accounts. This increases operations and maintenance expense since there is no longer any portion that is allowable to be capitalized. Since rent is an overhead that is not directly attributable to capital projects, it may no longer have any capitalized component.

4-SEC-14
[Ex.4/4/1/p.1-4]
Please update Tables 1-5 to include 2013 year-to-date actuals.

Response

Please refer to 4.0-Staff-20

4-Energy Probe-27

Ref: Exhibit 4, Tab 4, Schedule 2

a) Please explain the cost driver for Operations in Table 1(a) that talks about the focus shift from water to power business.

b) Please explain the cost driver for Administrative & General in Table 1(a) that states the movement to new depreciation approach - work associated with analysis for new system inputs. Why would this not be considered a one-time cost?

c) Under the Total area, the explanation includes a statement of inflation running at approximately 2-3%. Please provide a table that shows the percentage increases in inflation as measured by the GDP IPI FDD, the unionized staff wage increases and the non-union staff wage increases for each of 2009 through 2012 on an actual basis and the forecasts for 2013.

Response

a) The cost driver for Operations in Table 1(a) provides one explanation in the list that indicates there was an increase in costs because of a focus shift from the water business to the power business. This specifically relates to our SCADA employee. Please refer to 4-Energy Probe-29 PART i) which expands in detail the changing allocations of this employee.

b) The explanation, "Movement to new depreciation approach – work associated with analysis for new system input" relates to the change in useful life of assets based on the kinetrics study and the move to MCGAAP which requires componentization, tracking, and disposal of PP&E at a much more sophisticated level. Training, consultants, software, software support, and overtime will be required to implement an acceptable tracking system in 2013 to meet accounting standards.

c) Under the Total area, the explanations include a statement of inflation running at approximately 2-3%. The table below shows the actual percentage increase in inflation as measured by the GDP IPI FDD taken from Statistics Canada. The unionized and non-union staff wage increases for each year on actual bases have been provided. We are currently in union negotiations and therefore 2013 forecasted numbers could not be provided.

The GDP/IPI index represents specifically the Utility Industry. The Utility sector comprises establishments primarily engaged in operating electric, gas and water utilities. These establishments generate, transmit, control and distribute electric power; distribute natural gas; treat and distribute water; operate sewer systems and sewage treatment facilities; and provide related services, generally through a permanent infrastructure of lines, pipes and treatment and processing facilities.

The total Final Domestic Demand (FDD) is defined as the sum of final consumption, investment and stock building expenditures by the private and general government sectors in real terms.

PERCENTAGE INCREASE IN INFLATION

YRS	CPI	GDP/IPI	FDD	UNION WAGE	NON-UNION WAGE
2009	0.40	(2.60)	1.63	3.25%	3.00%
2010	2.50	1.30	1.73	0.40 Adj + 2.5%	3.00%
2011	3.10	4.30	1.80	3.00%	2.50%
2012	1.40	2.40	1.87	3.00%	2.50%
2013	1.30	3.50	1.88	In Negotiations	2.50%

4-SEC-15

[Ex.4/4/2/p.3]
Please provide a year-over-year OM&A Cost Driver Table for 2009-2013.

Response

Appendix 2-J
OM&A Cost Driver Table

OM&A	Last Rebasing Year (2009 Actuals)	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year
Reporting Basis					
Opening Balance	$ 3,744,382	$ 3,850,194	$ 3,995,851	$ 4,073,086	$ 4,843,306
Operations	-$ 33,570	$ 45,845	-$ 22,215	$ 79,314	$ 216,381
Maintenance	$ 70,596	-$ 65,363	$ 238,028	-$ 78,782	-$ 143,393
Billing & Collecting	$ 58,977	$ 54,645	-$ 144,005	$ 353,548	-$ 71,396
Community Relations	-$ 4,176	$ 55,317	-$ 13,619	-$ 11,431	$ 4,521
Administrative & General	$ 13,985	$ 55,213	$ 19,046	$ 427,571	-$ 94,258
Closing Balance	$ 3,850,194	$ 3,995,851	$ 4,073,086	$ 4,843,306	$ 4,755,160

OPERATIONS

	OEB Approved December 2009	December 2009	December 2010	December 2011	December 2012	December 2013
5005-0000-00 Opr Supervisn & Engnring	76,800	69,390	67,167	92,071	130,061	132,000
5010-0000-00 Opr Load Dispatching/SCADA	46,500	45,850	40,582	21,108	58,455	88,500
5012-0000-00 Opr Stn Buildgs & Fixtures Exp	19,000	17,217	35,190	31,478	23,199	27,000
5016-0000-00 Opr Dist Stn Equip - Labour					(0)	
5017-0000-00 Opr Dist Stn Equip - Other Exp	10,000	8,371	14,864			
5020-0000-00 Opr OH Dist Lines/Fdr - Labour	26,000	3,060		2,733	29,934	30,000
5025-0000-00 Opr OH Dist Lines/Fdr - Expnse		3,703	2,043	(140)	25,411	30,000
5030-0000-00 Opr OH Subtrans Feeder						
5035-0000-00 Opr OH Dist Transformers	3,500	34,577	62,321	46,410	27,408	34,800
5040-0000-00 Opr UG Dist Lines/Fdr - Labour				411	6,488	8,000
5045-0000-00 Opr UG Dist Lines/Fdr - Expnse			100		4,483	6,000
5055-0000-00 Opr UG Dist Transformers			2,592	18,363	5,535	12,000
5065-0000-00 Opr Meter Expense	1,500	9,006	949	8,472	4,124	6,000
5070-0000-00 Opr Customer Premise - Labour				909		
5085-0000-00 Opr Misc Distribution Exp	78,000	66,556	77,766	59,548	45,577	60,000
5096-0000-00 Rent - Stores & Operations Centre	30,000					172,800
	291,300	257,730	303,575	281,360	360,674	607,100
Change		(33,570)	45,845	(22,215)	79,314	246,426

	Actual to *Approvd 2009* VARIANCE	*2009 to 2010* VARIANCE	*2010 to 2011* VARIANCE	*2011 to 2012* VARIANCE	*2012 to 2013* VARIANCE	
5005-0000-00 Opr Supervisn & Engnring	(7,410)	(2,223)	24,903	37,990	1,939	1)
5010-0000-00 Opr Load Dispatching/SCADA	(650)	(5,268)	(19,474)	37,347	30,045	2)
5012-0000-00 Opr Stn Buildgs & Fixtures Exp	(1,783)	17,973	(3,712)	(8,279)	3,801	3)
5016-0000-00 Opr Dist Stn Equip - Labour	-	-	-	(0)	0	
5017-0000-00 Opr Dist Stn Equip - Other Exp	(1,629)	6,493	(14,864)	-	-	
5020-0000-00 Opr OH Dist Lines/Fdr - Labour	(22,940)	(3,060)	2,733	27,201	66	
5025-0000-00 Opr OH Dist Lines/Fdr - Expnse	3,703	(1,660)	(2,183)	25,552	4,589	
5030-0000-00 Opr OH Subtrans Feeder	-	-	-	-	-	
5035-0000-00 Opr OH Dist Transformers	31,077	27,744	(15,912)	(19,002)	7,392	4)
5040-0000-00 Opr UG Dist Lines/Fdr - Labour	-	-	411	6,077	1,512	
5045-0000-00 Opr UG Dist Lines/Fdr - Expnse	-	100	(100)	4,483	1,517	
5055-0000-00 Opr UG Dist Transformers	-	2,592	15,770	(12,828)	6,465	
5065-0000-00 Opr Meter Expense	7,506	(8,058)	7,523	(4,348)	1,876	
5070-0000-00 Opr Customer Premise - Labour	-	-	909	(909)	-	
5085-0000-00 Opr Misc Distribution Exp	(11,444)	11,211	(18,218)	(13,971)	14,423	5)
5096-0000-00 Rent - Stores & Operations Centre	(30,000)	-	-	-	172,800	6)
	(33,570)	45,845	(22,215)	79,314	246,426	
Sum of misc unhighlighted	(3,570)	127	6,486	3,977	29,158	

1. Operations Supervision & Engineering has an increase in 2011 related to less ability to capitalize wages and burdens for this particular year. The 2012 increase is mainly due to the hiring of an assistant to the superintendent.

2. The fluctuation in the SCADA expense is the result of this particular employees time alternating between various tasks as required and different company cost allocations. 4-Energy Probe-29 part i provides an in-depth analysis of the changes in wage allocations.

3. The substation operation and maintenance program has been expanded on an on-going basis for needed repairs and operational needs.

4. The operations overhead distribution transformers have some larger increases in 2009 and 2010 and then come down again in 2011 and 2012. The elimination of pole trans that are prone to failure is a key driver for this expense account.

5. The miscellaneous distribution account declined in 2011 and 2012 because insurance is no longer being allocated here, but rather now to 5635 and 5640 Insurance accounts in G&A. 2013 increases slightly to accommodate some of the training expenses that will no longer be allowed to be burdened and capitalized under MCGAAP.

6. The rent account was never used historically until 2013, when MCGAAP prevents the burdening of rent that could end up capitalized. Going forward this account will track rent for stores and garage outside of the burden process. In 2009 there is an approved OEB budget amount of $30,000. Since this account was never in use until 2013, it is unclear what previous management's thoughts were on the required $30k budget for this account. It appears likely that upon review of the general and administration expenses, where rent was missing in the 2009 OEB approved that the wrong rent line was selected in Operations instead of G&A.

MAINTENANCE

	OEB Approved December 2009	December 2009	December 2010	December 2011	December 2012	December 2013
5105-0000-00 Mtce Supervision & Engineering	62,000	61,532	53,872	110,368	133,263	60,000
5110-0000-00 Mtce of Station Buildings	26,000	11,523	11,674	6,364	10,728	12,000
5114-0000-00 Mtce Substn Equipment	59,600	46,985	84,325	45,212	56,938	52,000
5120-0000-00 Mtce Poles, Towers & Fixtures	68,225	135,579	137,523	167,965	180,084	184,000
5125-0000-00 Mtce OH Conductor & Devices	263,500	325,373	394,515	402,086	320,012	324,000
5130-0000-00 Mtce of OH Services	189,000	194,502	189,258	268,242	165,647	172,200
5135-0000-00 Mtce OH Dist Right of Way	190,534	151,176	154,774	150,791	197,211	100,000
5145-0000-00 Mtce of UG Conduit				10,000		
5150-0000-00 Mtce UG Conductor & Devices	120,000	131,859	96,017	104,815	117,438	117,000
5155-0000-00 Mtce of UG Services	236,500	253,331	242,337	246,024	239,402	228,000
5160-0000-00 Mtce Line Transformers	100,000	45,373	41,152	63,544	70,561	75,000
5175-0000-00 Mtce of Meters	259,500	288,221	174,645	242,710	248,054	241,700
5190-0000-00 Mtce W/Htr Controls-Labour						
	1,574,859	1,645,455	1,580,092	1,818,120	1,739,338	1,565,900
Change		70,596	(65,363)	238,028	(78,782)	(173,438)

	Actual to Approvd 2009 VARIANCE	2009 to 2010 VARIANCE	2010 to 2011 VARIANCE	2011 to 2012 VARIANCE	2012 to 2013 VARIANCE	
5105-0000-00 Mtce Supervision & Engineering	(468)	(7,660)	56,496	22,895	(73,263)	1)
5110-0000-00 Mtce of Station Buildings	(14,477)	151	(5,310)	4,364	1,272	
5114-0000-00 Mtce Substn Equipment	(12,615)	37,340	(39,113)	11,726	(4,938)	2)
5120-0000-00 Mtce Poles, Towers & Fixtures	67,354	1,944	30,442	12,120	3,916	
5125-0000-00 Mtce OH Conductor & Devices	61,873	69,142	7,571	(82,074)	3,988	
5130-0000-00 Mtce of OH Services	5,502	(5,244)	78,984	(102,595)	6,553	
5135-0000-00 Mtce OH Dist Right of Way	(39,358)	3,598	(3,983)	46,420	(97,211)	3)
5145-0000-00 Mtce of UG Conduit	-	-	10,000	(10,000)	-	
5150-0000-00 Mtce UG Conductor & Devices	11,859	(35,842)	8,798	12,623	(438)	
5155-0000-00 Mtce of UG Services	16,831	(10,994)	3,687	(6,622)	(11,402)	
5160-0000-00 Mtce Line Transformers	(54,627)	(4,221)	22,392	7,017	4,439	
5175-0000-00 Mtce of Meters	28,721	(113,576)	68,065	5,343	(6,354)	4)
5190-0000-00 Mtce W/Htr Controls-Labour	-	-	-	-	-	
5070-0000-00 Opr Customer Premise - Labour	70,596	(65,363)	238,028	(78,782)	(173,438)	

1. The maintenance and supervision has higher amounts in 2011 and 2012 because two supervisors were needed for a period of time to plan for the superintendent retiring. Partway through 2012 the superintendent retired and one of these positions was promoted. In 2013 a decline is seen as a result of the position change as well.

2. The substation operation and maintenance program has been expanded on an on-going basis for needed repairs and operational needs.

3. In 2013 a decision has been made to change to a 4 year cycle from a 3 year cycle to help ameliorate rate impacts on customers. This deferral is not seen as a risk to reliability or safety due to the accomplishments in this area in 2009 through 2012.

4. Maintenance of meters is lower in the 2009 to 2010 variance because so much work was being done on the new smart meter installation. It allowed for very little maintenance activity.

5. General comment: some fluctuation in account allocation is evident with the retirement of the superintendent and just general inconsistency in account selection of expenses. Going forward information has been provided so that expenses and time is more accurately tracked and posted on a consistent basis.

BILLING & COLLECTION

	OEB Approved 2009	*December 2009*	*December 2010*	*December 2011*	*December 2012*	*December 2013*
Billing and collecting:						
5305-0000-00 Billing Supervision	49,000	13,420		46,131	60,035	84,000
5310-0000-00 Meter Reading Expense	85,000	87,467	89,108	46,175	28,287	12,000
5310-0000-04 Meter Read - Smart Meter Operations					209,440	180,000
5315-0000-00 Customer Billing	489,093	492,772	491,705	386,889	370,657	372,000
5315-0000-04 Cust Billing - Smart Meter Operations					114,604	60,000
5315-0001-00 Customer Billing -Retailer Exp			15	1,362	10,720	7,200
5315-0002-00 EBT& EMERA Expense		84,567	87,803	80,803	77,664	79,476
5315-0003-00 Customer Final Bill Refunds		48	1,185	(340)	(593)	-
5315-0004-00 Bank Charges					14,267	15,600
5320-0000-00 Collecting	69,000	59,618	104,753	86,670	100,646	93,000
5320-0001-00 Collecting - Insurance - Business Credit				16,000	17,280	26,586
5325-0000-00 Collecting Cash Over & Short		1,042	(57)	4,495	(73)	-
5335-0000-00 Bad Debt Expense	70,000	82,135	93,161	58,406	82,323	84,000
5415-0000-00 Energy Conservation			8,041	5,117		
	762,093	821,070	875,715	731,709	1,085,258	1,013,862
Change		58,977	54,645	(144,005)	353,548	(71,396)

	Actual to *Approvd 2009* VARIANCE	*2009 to 2010* VARIANCE	*2010 to 2011* VARIANCE	*2011 to 2012* VARIANCE	*2012 to 2013* VARIANCE	
Billing and collecting:						
5305-0000-00 Billing Supervision	(35,580)	(13,420)	46,131	13,904	23,965	1)
5310-0000-00 Meter Reading Expense	2,467	1,641	(42,933)	(17,888)	(16,287)	2)
5310-0000-04 Meter Read - Smart Meter Ope	-	-	-	209,440	(29,440)	3)
5315-0000-00 Customer Billing	3,679	(1,067)	(104,816)	(16,231)	1,343	
5315-0000-04 Cust Billing - Smart Meter Ope	-	-	-	114,604	(54,604)	4)
5315-0001-00 Customer Billing -Retailer Exp	-	15	1,347	9,358	(3,520)	
5315-0002-00 EBT& EMERA Expense	84,567	3,236	(7,000)	(3,139)	1,812	5)
5315-0003-00 Customer Final Bill Refunds	48	1,137	(1,526)	(253)	593	
5315-0004-00 Bank Charges	-	-	-	14,267	1,333	
5320-0000-00 Collecting	(9,382)	45,135	(18,083)	13,976	(7,646)	
5320-0001-00 Collecting - Insurance - Busines	-	-	16,000	1,280	9,306	
5325-0000-00 Collecting Cash Over & Short	1,042	(1,099)	4,552	(4,568)	73	
5335-0000-00 Bad Debt Expense	12,135	11,026	(34,755)	23,917	1,677	6)
5415-0000-00 Energy Conservation	-	8,041	(2,924)	(5,117)	-	
	58,977	54,645	(144,005)	353,548	(71,396)	

1. In 2009, the billing supervisor went on a sudden disability leave and was never able to return. The billing supervision allocation appears to have never been adjusted for

employees and contract workers filling in. This corrects in 2011. An outside service was required in 2010 to assist with the fill-in for the disabled employee and the cost for the support was significant. Please see 4-SEC-11 which provides more details and expands on the fluctuating seen in general in this category for 5305, 5315, 5320.

2. Meter reading expense declines with the implementation of smart meters in 2009.

3. Meter reading – Smart Meter Operations is a new account with the implementation of new smart meters. It increases in 2012 with the accumulated deferral account allocated fully to the expense in the year. 2013 declines because the prior year includes more than one year of operations expense in the allocation of the deferral.

4. Same as 3 above.

5. The EBT & EMERA expense does not appear to have been budgeted in the OEB 2009 approved year.

6. The average bad debt expense is $80,000 over the 5 years. The OEB approved in 2009 is $70k and the 2013 forecast is $84,000 which is reasonable.

COMMUNITY RELATIONS

	OEB Approved 2009	*December 2009*	*December 2010*	*December 2011*	*December 2012*	*December 2013*
5425-0000-00 Misc Cust Ser&Inform Expenses	107,389	103,213	158,530	144,911	133,479	138,000
Change		**(4,176)**	**55,317**	**(13,619)**	**(11,431)**	**4,521**

	Actual to *Approvd 2009* VARIANCE	*2009 to 2010* VARIANCE	*2010 to 2011* VARIANCE	*2011 to 2012* VARIANCE	*2012 to 2013* VARIANCE
5425-0000-00 Misc Cust Ser&Inform Expenses	(4,176)	55,317	(13,619)	(11,431)	4,521

1. Looking at the Miscellaneous Customer Service & Information expense account on its own makes meaningful analysis difficult. The analysis in 4-SEC-11 provides a detailed analysis of the variance. The issue seems to be with the allocation of wages within this category and other billing and collecting accounts that include wages. There was shuffling around of job positions with one staff person in billing going on a sudden disability leave. But the overall analysis in 4-SEC-11 provides a much more consistent view.

GENERAL & ADMINISTRATION

	OEB Approved 2009	December 2009	December 2010	December 2011	December 2012	December 2013
General & Administration:						
5605 5610 5615 Executive, Management, Admin Salaries & Expenses	747,241	736,804	819,531	672,693	872,221	831,600
5620-0000-00 Office Supplies & Expenses				79		
5630-0000-00 Outside Services	181,500	183,125	150,000	146,229	306,333	216,000
5635-0000-00 Property Insurance	2,000	671	1,506	35,412	28,117	28,887
5640-0000-00 Injuries and Damages	1,000	2,105		46,803	53,947	64,800
5646-0000-01 Employee Pensions & OPEB - Cur Service Cost					7,681	9,114
5646-0000-02 Employee Pensions & OPEB - Interest Cost					18,496	17,297
5646-0000-03 Employee Pensions & OPEB - Actuarial Gain/Loss						1,118
5646-0000-04 Employee Pensions & OPEB - Past Service Cost					4,087	4,087
5646-0000-05 Employee Pensions & OPEB - Contribution Payments					(30,616)	(28,310)
5655-0000-00 Regulatory Expenses	43,000	29,515	34,323	42,004	84,015	81,000
5660-0000-00 General Advertising Expenses	7,500				2,184	2,000
5665-0000-00 Miscellaneous General Expenses	5,000			1,971	(8,662)	
5665-0001-00 Misc Gen Exp - Membership Fees & Dues	-				81,253	90,000
5670-0000-00 Rent		40,000	40,000	43,200	43,200	43,200
5675-0000-00 Maintenance of General Plant	21,500	22,140	22,459	91,537	22,372	30,000
5680-0000-00 Electrical Safety Author Fees	-	8,365	8,518	6,699	7,011	8,040
5681-0000-00 OEB Special Purpose Charge Expense						
6105-0000-00 Taxes Other Than Income Taxes			1,602			
6205-0000-00 Donations	-	-	-	4,495	25,225	21,000
6205-0001-00 Low-Income Energy Assistance	-	-	-	5,864	7,693	10,465
Total General & Administration	1,008,741	1,022,725	1,077,939	1,096,985	1,524,557	1,430,298
		13,984	55,214	19,046	427,571	(94,258)

	Actual to Approvd 2009 VARIANCE	2009 to 2010 VARIANCE	2010 to 2011 VARIANCE	2011 to 2012 VARIANCE	2012 to 2013 VARIANCE	
5605 5610 5615 Executive, Management, Admin Salaries & Expenses	(10,437)	82,727	(146,838)	199,527	(40,621)	1)
5620-0000-00 Office Supplies & Expenses	-	-	79	(79)	-	
5630-0000-00 Outside Services	1,625	(33,125)	(3,771)	160,104	(90,333)	2)
5635-0000-00 Property Insurance	(1,329)	835	33,906	(7,295)	770	3)
5640-0000-00 Injuries and Damages	1,105	(2,105)	46,803	7,144	10,853	3)
5646-0000-01 Employee Pensions & OPEB - Cur Service Cost	-	-	-	7,681	1,433	4)
5646-0000-02 Employee Pensions & OPEB - Interest Cost	-	-	-	18,496	(1,199)	4)
5646-0000-03 Employee Pensions & OPEB - Actuarial Gain/Loss	-	-	-	-	1,118	4)
5646-0000-04 Employee Pensions & OPEB - Past Service Cost	-	-	-	4,087	-	4)
5646-0000-05 Employee Pensions & OPEB - Contribution Payments	-	-	-	(30,616)	2,306	4)
5655-0000-00 Regulatory Expenses	(13,485)	4,808	7,681	42,011	(3,015)	5)
5660-0000-00 General Advertising Expenses	(7,500)	-	-	2,184	(184)	
5665-0000-00 Miscellaneous General Expenses	(5,000)	-	1,971	(10,632)	8,662	
5665-0001-00 Misc Gen Exp - Membership Fees & Dues	-	-	-	81,253	8,748	6)
5670-0000-00 Rent	40,000	-	3,200	-	-	7)
5675-0000-00 Maintenance of General Plant	640	320	69,078	(69,165)	7,628	8)
5680-0000-00 Electrical Safety Author Fees	8,365	153	(1,820)	312	1,029	
5681-0000-00 OEB Special Purpose Charge Expense	-	-	-	-	-	
6105-0000-00 Taxes Other Than Income Taxes	-	1,602	(1,602)	-	-	
6205-0000-00 Donations	-	-	4,495	20,730	(4,225)	
6205-0001-00 Low-Income Energy Assistance	-	-	5,864	1,829	2,772	
Total General & Administration	13,984	55,214	19,046	427,571	(94,258)	

1. In 2012 there was significant overtime and extra effort by staff and the board put into tasks required for the PowerStream sale of shares. There was also a retirement allowance paid in 2012. Some change in the allocation between outside services and the actual wages accounts charged from the Solutions Company is also evident.

2. Higher accounting fees in 2012 were required to deal with the absence of the CFO and assist with duties required for the PowerStream sales of shares. These accounting costs are not share transaction costs. Additional legal was also required for the review of the new Infrastructure Ontario loan.

3. As per note 5 in the Operations section, the miscellaneous distribution account declined in 2011 and 2012 because insurance is no longer being allocated there, but rather now to 5635 and 5640 Insurance accounts in G&A.

4. New accounts set up to track changes in the employee future benefits in accordance with OEB handbook direction.

5. Increasing regulatory expenses the result of ongoing increases in fees and requirements by the OEB as well as the significant expense incurred for the application which will be written off over 4 years.

6. Prior to 2012 membership expenses were mainly recorded in General and Administrative costs (accounts 5610 and 5615). Starting in 2012 these items are being recorded in G&A account 5665 - Miscellaneous General Expenses, consistent with the Accounting Procedures Handbook.

7. In 2009 there is an approved OEB budget amount of $30,000 rent in Operations, but there is no actual expense. See note 5 operation section above. It appears likely that upon review of the general and administration expenses, where rent was missing in the 2009 OEB approved that the wrong rent line was selected in Operations instead of G&A.

8. Maintenance charges from Collingwood Public Utilities Service Board (Water Company) in 2011 peak for property and building maintenance work and the allocation of a unionized employee in water performing the duties that are now conducted at a lower cost by an outside cleaning contractor.

4-Energy Probe-28

Ref: Exhibit 4, Tab 4, Schedule 3

a) What is the relationship between the $72,000 noted on line 7 and the $172,800 shown in Table 1?

b) Please provide more detail on the rent charged directly to OM&A. In particular, what is being rented and from whom is it being rented?

Response

a) The $72,000 noted on line 7 of E4/T4/S3 represents an estimate of the amount of rent, sick, vacation and training that previously would have been capitalized from the burden accounts prior to the change to MCGAAP. The $172,800 shown in Table 1 is the total rent that was previously burdened to operations, stores and vehicle. When the burdens were allocated most would end up in O&M accounts, but some would end up in capital. The following table which is from Appendix 2-J outlines the breakdown for the $72,000 estimate as follows:

MIFRS - Costs no longer capitalized:	2013 Total	Capitalization % (CGAAP)	2013 CGAAP Capitalized	2013 MIFRS Capitalized	Increase in OM&A
Stores - Rent	$ 86,400	50.0%	$ 43,200	$ -	$ 43,200
Vehicle - Rent	$ 86,400	8.4%	$ 7,232	$ -	$ 7,232
Sick expense	$ 17,600	8.4%	$ 1,473	$ -	$ 1,473
Vacation expense	$ 96,600	8.4%	$ 8,085	$ -	$ 8,085
Safety and training expense	$ 139,300	8.4%	$ 11,659	$ -	$ 11,659
Total	$ 426,300		$ 71,650	$ -	$ 71,650

The following table shows how rent was posted before and after the change to MCGAAP:

Under MCGAAP

ACCT	DESCRIPTION	MONTHLY	ANNUALLY
5096	Rent - Stores & Operations centre	14,400	172,800
5670	Rent - General & Administration	3,600	43,200
		18,000	216,000

Previous Allocation before MCGAAP - (2012 and prior)

ACCT	DESCRIPTION	MONTHLY	ANNUALLY
9040	Burden - Stores	7,200	86,400
9070	Budren - Vehicles	7,200	86,400
5670	Rent - General & Administration	3,600	43,200
		18,000	216,000

b) Collus PowerStream rents the land and building it uses for operations and administration from Collingwood Public Utilities Service Board at a cost of $216,000 annually. The administration building, land, stores, and vehicle garage are part of this rent. The shared services agreement recently completed by Howard Gorman and included in the interrogatory responses, includes the cost allocation to support the amount charged for building rent.

4-SEC-16
[Ex.4/4/3/p.1]
Please explain the changes in the allocated rent for Storages and Vehicles.

Response

Please refer to 4.0-Staff-23

4-Energy Probe-29

Ref: Exhibit 4, Tab 4, Schedule 4

a) Please explain why Collus PowerStream incurred any costs in 2012 related to the 50% share transaction with PowerStream and the parent company of Collus PowerStream.

b) Please provide the total costs included in the 2012 OM&A of $4,843,305 associated with the 50% share transaction with PowerStream. Please also provide a breakdown of these costs.

c) Would the costs associated with the 50% share transaction with PowerStream be considered a one-time cost to Collus PowerStream? If not, please explain why not.

d) Please provide the cost in 2012 associated with the buy out/early retirement for a former senior employee. Has Collus PowerStream had any similar costs in 2009 through 2011? If yes, please quantify by year. Are any similar costs forecast for 2013? If yes, please quantify.

e) If not included in the response to part (b) above, please provide the 2012 costs paid to Solutions for additional services they provided on the transaction.

f) If not included in the response to part (b) above, please provide the additional 2012 costs associated with the audit associated with the share acquisition.

g) Does Collus PowerStream expect to issue any new debt in 2013? If no, please provide the additional legal cost incurred in 2012 associated with the review of the Infrastructure Ontario loan.

h) Please indicate the level of legal costs incurred in 2012 associated with the PowerStream share transaction if these costs are not included in the response to part (b) above.

i) Please explain the increase forecast for 2013 for load dispatching costs that result from an employee's time now being more fully allocated to work in Collus PowerStream rather than the water affiliate as a direct result of a change in his activities. In particular, please explain how this function was performed before and after the change in activities and why there is an increase in the costs.

Response

a) Collus PowerStream incurred no "Sales Transaction Costs" in 2012 related to the 50% share transaction with PowerStream and the parent company of Collus PowerStream because they were re-billed to the shareholder, The Town of Collingwood, and reimbursed by them. However, in 2012, Collus PowerStream did pay some additional general and administrative costs that were not "Sales Transaction Costs", but were incurred as a result of the transaction. These additional costs have been provided in 1-Energy probe-2.

b) The total costs included in the 2012 OM&A of $4,843,305 associated with the 50% share transaction with PowerStream have been provided in 1-Energy probe-2.

c) The costs associated with the 50% share transaction with PowerStream would be considered a one-time cost to the Town of Collingwood, not Collus PowerStream because they were paid by the Town.

   The additional general and administrative costs (see 1-Energy Probe-2) that were not "Sales Transaction Costs", but were incurred as a result of the transaction are mostly one-time costs. The Infrastructure Ontario legal fees for new debt will continue as a result of on-going capital financing requirements and maintenance of the 60-40 debt to equity structure in the amount of about $12,000. The additional audit will not be required, but June 30th interim financial statements are now required for Infrastructure Ontario for the new debt covenants and this was not previously required. Part of the July 31, 2012 audit was also used to satisfy year-end audit requirement work as well. Going forward dividends to the shareholder will be declared which were never done in the past and related legal and accounting fees will be payable. A reasonable estimate would be that $20-25k of the extra 2012 audit and accounting fees are going to make up part of the on-going expense requirements of the corporation in future years.

d) Collus PowerStream will not disclose the cost in 2012 associated with the buy out/early retirement for a former senior employee as this constitutes confidential personal information. Collus PowerStream has not had any similar costs in 2009 through 2011. No similar costs are forecasted for 2013. No buy/out retirements were initiated by the PowerStream deal.

e) There are no 2012 costs paid to Solutions for additional services they provided on the transaction.

   The only indirect additional expenses paid to Solutions would be for unused vacation time for executive members and bonuses for extra work performed by shared employees related to the sales transaction. Please refer to exhibit 4/tab 4/schedule 5 Compensation table for further information.

f) Part (b) above, includes a reference to 1-Energy Probe-2 which provides the additional 2012 costs associated with the audit associated with the share acquisition.

g) Yes, Collus PowerStream expects to issue new debt in 2013.

h) All legal costs were paid by the Town of Collingwood in 2012 associated with the PowerStream share transaction. The only legal costs incurred by Collus PowerStream were for the review of the new Infrastructure Ontario loan as included in 1-Energy Probe-2.

i) The increase forecast for 2013 for load dispatching costs result from an employee's time now being more fully allocated to work in Collus PowerStream rather than the water affiliate as a direct result of a change in his activities. The water affiliate required additional services to set up their own SCADA system and this employee assisted with the IT infrastructure installation process which is now complete. The water staff now maintains their own SCADA system independently. Also, two new IT employees have been hired in Collus PowerStream Solutions to deal with the ever growing IT needs of the Water Company, The Town, and Collus PowerStream. So this particular SCADA employee has much less IT involvement for other companies.

   Another explanation for the increase is that account 1532 Renewable Connection OM&A deferral account had the following amounts tracked for the SCADA employee’s work on renewable connection, which has not had any further allocation to the deferral account after May 2012.

2010	25,768.04
2011	27,783.14
2012	17,236.12
	70,787.30

   This employee also handles some of the operation building maintenance issues. As the employee’s tasks change the accounts to which his salary is allocated also change. In a small utility the flexibility to wear many hats is important. Going forward this SCADA employee will be redirecting more of his time to the Collus PowerStream SCADA system and working in conjunction with PowerStream on planned projects such as, Master Station and Control Room Interoperability. His focus on his primary SCADA job is necessary and therefore the ability to split his time to many areas has been limited.

4.0-Staff-25

Ref: E4/T4/S5, p.3 Table1 and E4/T4/S5, p.4 Table 2 and E4/T5/S1, p.1 – Total Compensation

For the 2013 Test Year Table 1 shows a total compensation amount of $2,459,679 and a total compensation charged to OM&A of $2,253,759. Table 2 – Changes in Salaries and Wages 2009 to 2013 shows total Salary and Wages of $2,035,604.

a) Please reconcile the two tables.

On page 1 of E4/T5/S1 Collus PowerStream states that PowerStream' Inc's purchase of 50% interest in Collingwood Utility Service Corp. (CUSC, "allows for the efficiencies of scale and provides cumulative benefits and savings" as well as "benefits are: provision of strategic and specialized resources such as back office support in finance and regulatory processes".

b) Please provide further detailed explanation for the 86% increase in non-union and part-time salaries in 2013 over 2009 actual.

    i. Please discuss the impact of PowerStreams purchase of 50% interest in Collingwood Utility Service Corp. (CUSC) on wages, in particular for non-union and part-time staff.

    ii. Please discuss any efficiency gains in the test year. Please provide a forecast of expected efficiency gains for the subsequent years.

    iii. If there are no gains, please explain why.

Response

a) E4/T4/S5, Table 1, page 3 shows the following in the third section down entitled "Total Salaries and Wages":

Executive & Management	429,991.00
Non-Union + Part Time	715,626.00
Union	889,987.00
	2,035,604.00

These amounts exactly agree to E4/T4/S5, table 2, page 4. Table two provides a summary of changes in the total salaries and wages. This does not include benefits, accrued pension, and post-retirement benefits.

b) The actual increase in total non-union and part-time staff is only $194,997 or 22% before allocations to affiliate corporations through Collus PowerStream

Solutions. Work load for the Town of Collingwood and Collingwood Public Utilities Service Board (Water Company) fluctuates based on the direct activities of employees. A greater allocation in recent years to Collus PowerStream is a result of increasing demands related to smart meters, more complex billing and collecting regulations, time-of-use billing, a new customer billing software, the complexity of the number of electricity rate classes, increased regulatory requirements, 2012 cost of service application, conservation and demand, IFRS, changes to capital asset policies and modifications of their useful lives, and the growth in the community and the infrastructure. The reason for the increase from 2009 to 2013 is summarized in the table below:

	2009 LRY - Board Approved	2009 LRY - Actual	2010 Historical Year 2	2011 Historical Year 1	2012 Bridge Year	2013 Test Year
Total Non-Union+Part-time Collus PowerStream & Collus PowerStream Solutions		895,600	899,014	926,602	983,556	1,090,597
Less Shared Employees from Solutions Charged to Affiliates		(510,492)	(489,963)	(509,631)	(446,801)	(374,971)
Total Non-Union+Part-time as per Table 1 Compensation		385,108	409,052	416,971	536,755	715,626
					Increase $	$330,518
					Increase %	86%
	Increase attributable to allocation difference				41%	$135,521
	Increase attributable to wage increases (approx)				15%	$48,670
	Increase attributable to new hires / succession planning				44%	$146,327
					100%	$330,518

Over the last five years only one entry level Customer Service Representative was hired and one operations support person to assist the Superintendent. All other positions in this category have remained the same.

Notably, from 2010 to 2012 we had staff turnover of six key employees in just these few years. The CFO, Controller, Superintendent, Regulatory Manager, and Billing Clerk retired and the Senior Billing Clerk went off on a sudden disability leave. Some of these positions are executive level, but all of them put extra strain on the workload of the entire staff and required an overlap of employees for succession planning that impacts the non-union category.

i. The impact of PowerStream's purchase of 50% interest in Collingwood Utility Service Corp. (CUSC) has had no impact on wages in general or on wages related to non-union and part-time staff at this point in time.

ii. There are no efficiency gains in the test year. Strategic and specialized resources such as back office support in finance and regulatory processes relate more to the replacement of outside regulatory consultants and service providers. The company has no intention of reducing staff levels through the termination of employment. The expectation of efficiency gains related to staff in subsequent years may eventually occur through the normal retirement process.

iii. E4/T1/S2 page two states, "Although **savings are not quantifiable at this time** Collus PowerStream believes that the partnership will assist in **future mitigation** of upward pressure on distribution rates." The PowerStream deal was dated July 31st, 2012 with final closing not until March 1, 2013. Therefore, it would not be reasonable to have any expectations that efficiency gains could be realized this quickly. It is too premature to determine what those savings will be. Also, please refer to the response for interrogatory 1-Energy Probe-4 and 4-Energy Probe-26.

4-Energy Probe-30

Ref: Exhibit 4, Tab 4, Schedule 5

The evidence on page 2 indicates unionized increases of 2.5%, 3.0% and 3.0%, but lists four years (2010 through 2013). Please show the increases applicable to each of 2010, 2011, 2012 and 2013.

Response:

2010	2011	2012	2013
.40 Adjustment + 2.5%	3%	3%	In negotiations

4-Energy Probe-31

Ref: Exhibit 4, Tab 4, Schedule 5

a) Does Table 1 reflect actual final data for 2012? If not, please update Table 1 to reflect actual data for 2012.

b) Please provide a table for 2009 through 2013 that shows the total incentive paid each year, the total potential incentive available each year and the corresponding ratio of incentive payments to maximum incentives available.

c) Please provide the type of performance targets that are used to evaluate the amount of incentive payment available to each of the four categories of employees shown under Variable Compensation in Appendix B.

Response

a) Yes, table 1 reflects actual final data for 2012.

b) Total incentive pay compared to potential available and the corresponding ratio:

	2009	2009	2010	2011	2012	2013
	LRY - Board Approved	LRY - Actual	Historical Year 2	Historical Year 1	Bridge Year	Test Year
Compensation - Yearly Incentive Pay						
Executive & Management	-	16,500	21,634	20,350	74,525	32,662
Non-Union+Part-time	-	2,750	3,465	2,475	3,850	3,754
Union	-	-	-	-	-	-
Total	**-**	19,250	25,099	22,825	78,375	36,416
Potential Incentive		48,400	50,600	42,350	97,350	53,900
Ratio		39.77%	49.60%	53.90%	80.51%	67.56%

*2012 increase result of extra workload related to the PowerStream closing. 2013 returns to normalized levels.

c) Annual incentive bonuses are meant to be motivational. They are designed to reward employees for fulfilling their responsibilities and for delivering superior results. Bonus targets and their associated payouts reflect:

- a range of expected levels of performance (minimum to maximum)
- various levels of difficulty of specific tasks

- the likelihood of achievement
- the timeliness of completion
- shareholder satisfaction
- customer satisfaction
- the economic health of the company

Performance targets that are used.

- – Individual performance targets established annually.
- – Incentive/Bonus Payment Structure:
  - ~ President & CEO – up to 10% of salary
  - ~ Executive Management – up to 8% of salary
  - ~ Management – up to 3% of salary
  - ~ Others – up to 1.5% of salary

4-SEC-17
[Ex.4/4/5/Appendix B]
Please detail the Incentive/Bonus Payment system.

Response

Please refer to 4-Energy Probe -31

4-Energy Probe-32

Ref: Exhibit 4, Tab 4, Schedule 7 &
Exhibit 2, Tab 2, Schedule 1 &
RRWF

The depreciation expense for 2013 found in Table 2 of Exhibit 4, Tab 4, Schedule 7 matches that found in Table 7 of Exhibit 2, Tab 2, Schedule 1.

a) **Please explain the difference in the depreciation expense of $946,065 found in Table 7 of Exhibit 2, Tab 2, Schedule 1 and the expense of $948,979 found in the RRWF.**

b) **Please explain why in Table 7 of Exhibit 2, Tab 2, Schedule 1, an amount of $35,241 is added to the depreciation expense for stranded meters, when stranded meters have been removed from rate base at the end of 2012.**

Response

a) The $2,914 difference in the depreciation expense of $946,065 found in Table 7 of Exhibit 2, Tab 2, Schedule 1 and the expense of $948,979 found in the RRWF has been explained in the table below:

	E2/T2/S1 Table 7	RRWF
Accumulated Amortization Addition	1,102,871.00	1,102,871.00
Less Burdened Vehicle Amortization	(192,047.00)	(192,047.00)
Add Stranded Meter Amortization	35,241.00	
Add Amortization of Intangible assets		8,155.00
Add Derecognition Expense		30,000.00
	946,065.00	948,979.00

b) In Table 7 of Exhibit 2, Tab 2, Schedule 1, an amount of $35,241 is added to the depreciation expense for stranded meters because even though stranded meters have been removed from PP&E at the end of 2012, the amortization continues on the stranded meters sitting in regulatory assets until September 1, 2013 when new rates become effective.

4-SEC-18
[Ex.4/4/7/p.2]
Where applicable, please explain the Applicant's variance from the Asset Depreciation Study conducted by Kinectrics.

Response

Please refer to 2.0-VECC-10

4.0-Staff-26

Ref: E4/T4/S8, Appendix A 2012 Income Tax Return: Schedule 1-Net Income(loss) for Income Tax Purposes; E4/T4/S8, Appendix B, Income Tax/PILS Work form (WF) for 2013 Filers: Adjusted Taxable Income-Bridge Year Tab

Board staff notes the differences between the amounts in the PILS WF, Adjusted Table Income Bridge Year, and Schedule 1 of the 2012 income tax return for the following items: net income before PILs, and the amortization of tangible assets and the reserve balance from the financial statements, at the end of the year for 2012 was performed Board staff notes the differences in the table below.

2012 Bridge Year

	Net Income Before PILS	**Amortization of Tangible Assets**	**Reserves from the Financial Statements-bal. at the end of the year**
PILS WF: Adjusted Taxable Income	680,119	1,888,095	365,620
2012 Income Tax Return- Sch.1	$468,411	$1,053,169	$336,468
Difference	**211,708**	834,926	29,152

a) Please explain and reconcile the differences.
b) Please confirm if the data used in the PILS WF for Adjusted Taxable Income conforms to the figures in the Income Tax Return for the bridge year. If not, please make the necessary adjustments.

Response:

a) Net Income before PILs:

   The amount of $468,411 shown in the table above is the net income before adjustments on schedule 1 of the 2011 tax return. The corresponding amount from the 2012 tax return is $145,964.

   Please note that there are two sets of tax returns in E4/T4/S8 Appendix A, first is the tax return for the year ending December 31, 2011, followed by the tax return for the year ended December 31, 2012.

   The amount of $680,119 is the after-tax Board allowed rate of return on the 2012 calculated rate base amount. Collus used this amount in the PILs WF so that 2012 PILs calculation is consistent with and comparable to the test year calculation.

The most comparable number on the 2012 tax return is the $145,964 net income from the financial statements plus the add back of the accounting tax provisions of ($19,068) current taxes and $179,288 deferred taxes for a net income before taxes of $306,184. The difference of $373,935 ($680,119-$306,184) simply indicates that Collus earned less than the allowed rate of return in 2012.

Amortization of Tangible Assets:

The amount of $1,053,169 shown in the table above is the amortization of tangible assets before adjustments on schedule 1 of the 2011 tax return. The corresponding amount from the 2012 tax return is $1,739,853.

The amount of $1,888,095 is the total amount of depreciation calculated for 2012. Please see the response to 2.0-Staff-6 for further details on the amounts of $1,888,095 and $1,739,853, and the difference of $148,242.

The amount of $1,793,852 represents the depreciation of $1,888,095, used in the PILs WF, reduced by the depreciation on transportation equipment of $179,188 and the addition of $22,791 for depreciation on stranded meters recorded in account 1556 plus amortization of intangible assets of $8,155. In the PILs WF, Collus has added back the full depreciation booked of $1,888,095, irrespective of the fact that some of the expense was shown in other lines than depreciation expense and believes that this is correct. In the tax return only the depreciation expense shown on the depreciation line has been added back. For tax purposes all depreciation should be added back then CCA deducted.

Reserves from the Financial Statements-bal. at the end of the year:

The reserve from the financial statements is the Accrued Benefit Obligation (ABO) for post-retirement benefits. The amount of $365,620 was an estimate based on the 2011 year end amount of $336,820 plus an average annual increase of $28,800 from 2009 to 2011. This estimate was used prior to the availability of the 2012 financial statements and tax returns. Updating this based on the information in the 2012 statements and returns was missed. The updated ABO financial statement reserve information is summarized in Table Staff-26-1:

Table Staff-26-1: ABO Financial Statement Reserve Information

Year end	Amount
2009	$ 281,085
2010	$ 308,029
2011	$ 336,820
2012	$ 336,468

2009 to 2012 Change	$	55,383
Years	$	3
Average annual change	$	18,461
Projected 2013	$	354,929

This updated information results in new opening and estimated closing balances for the Financial Statement Reserves in the 2013 Test Year PILs calculation as discussed further in part (b).

b) As explained in part (a) above there are some differences between the amounts used in the 2012 PILS WF and the 2012 tax returns. Collus used the same Schedule 8 Capital Cost Amounts and Schedule 10 Cumulative Eligible Capital amounts from the 2012 tax return in the PILs WF.

The only difference that impacts the 2013 Test Year PILs calculation is the change in the Financial Statement Reserves discussed in part (a) above.

As requested, Collus has updated the PILs WF using the amounts from the 2012 tax return and updating 2013 for the updated financial statement reserve amounts from part (a).

This has resulted in a change in the 2013 Test year income taxes/PILs from $73,876 to $71,979. The change in taxable income and resulting tax decrease is due to the change in the schedule 13 reserve amounts.

v 2.0

Income Tax/PILs Workform for 2013 Filers

Utility Name	COLLUS Power Corp.
Assigned EB Number	EB-2012-0116
Name and Title	Cindy Shuttleworth, Chief Financial Officer
Phone Number	705.445.1800 (2270)
Email Address	cshuttleworth@collus.com
Date	30-Apr-13
Last COS Re-based Year	**2009**

Note: Drop-down lists are shaded blue; Input cells are shaded green.

Income Tax/PILs Workform for 2013 Filers

Rate Base			$	20,253,098	
Return on Ratebase					
Deemed ShortTerm Debt %	4.00%	T	$	810,124	*W = S * T*
Deemed Long Term Debt %	56.00%	U	$	11,341,735	*X = S * U*
Deemed Equity %	40.00%	V	$	8,101,239	*Y = S * V*
Short Term Interest Rate	2.07%	Z	$	16,770	*AC = W * Z*
Long Term Interest	4.05%	AA	$	459,121	*AD = X * AA*
Return on Equity (Regulatory Income)	8.98%	AB	$	727,491	*AE = Y * AB*
Return on Rate Base			$	1,203,382	*AF = AC + AD + AE*

Questions that must be answered	Historic	Bridge	Test Year
1. Does the applicant have any Investment Tax Credits (ITC)?	Yes	No	No
2. Does the applicant have any SRED Expenditures?	Yes	No	No
3. Does the applicant have any Capital Gains or Losses for tax purposes?	No	No	No
4. Does the applicant have any Capital Leases?	No	No	No
5. Does the applicant have any Loss Carry-Forwards (non-capital or net capital)?	No	No	No
6. Since 1999, has the applicant acquired another regulated applicant's assets?	Yes	Yes	Yes
7. Did the applicant pay dividends? *If Yes, please describe what was the tax treatment in the manager's summary.*	No	No	No
8. Did the applicant elect to capitalize interest incurred on CWIP for tax purposes?	No	No	No

Tax Rates **Federal & Provincial** **As of June 20, 2012**	**Effective** ################	**Effective** ################	**Effective** ################	**Effective** ################
Federal income tax				
General corporate rate	38.00%	38.00%	38.00%	38.00%
Federal tax abatement	-10.00%	-10.00%	-10.00%	-10.00%
Adjusted federal rate	28.00%	28.00%	28.00%	28.00%
Rate reduction	-11.50%	-13.00%	-13.00%	-13.00%
	16.50%	15.00%	15.00%	15.00%
Ontario income tax	11.75%	11.50%	11.50%	11.50%
Combined federal and Ontario	28.25%	26.50%	26.50%	26.50%
Federal & Ontario Small Business				
Federal small business threshold	500,000	500,000	500,000	500,000
Ontario Small Business Threshold	500,000	500,000	500,000	500,000
Federal small business rate	11.00%	11.00%	11.00%	11.00%
Ontario small business rate	4.50%	4.50%	4.50%	4.50%

Income Tax/PILs Workform for 2013 Filers

Schedule 8 - Historical Year

Class	Class Description	UCC End of Year Historic per tax returns	Less: Non-Distribution Portion	UCC Regulated Historic Year
1	Distribution System - post 1987	7,191,139		7,191,139
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election			0
2	Distribution System - pre 1988			0
8	General Office/Stores Equip	161,095		161,095
10	Computer Hardware/ Vehicles	603,296		603,296
10.1	Certain Automobiles			0
12	Computer Software	525		525
13_1	Lease # 1			0
13_2	Lease #2			0
13_3	Lease # 3			0
13_4	Lease # 4			0
14	Franchise			0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs			0
42	Fibre Optic Cable			0
43.1	Certain Energy-Efficient Electrical Generating Equipment			0
43.2	Certain Clean Energy Generation Equipment			0
45	Computers & Systems Software acq'd post Mar 22/04			0
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)			0
47	Distribution System - post February 2005	9,208,802		9,208,802
50	Data Network Infrastructure Equipment - post Mar 2007	13,060		13,060
52	Computer Hardware and system software			0
95	CWIP			0
				0
				0
				0
				0
				0
				0
				0
				0
				0
				0
	SUB-TOTAL - UCC	17,177,917	0	17,177,917

Income Tax/PILs Workform for 2013 Filers

Schedule 10 CEC - Historical Year

Cumulative Eligible Capital				582,665
Additions				
Cost of Eligible Capital Property Acquired during Test Year				
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	x 1/2 =	0	
			0	0
Amount transferred on amalgamation or wind-up of subsidiary	0			0
Subtotal				582,665
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year				
Other Adjustments	0			
Subtotal	0	x 3/4 =		0
Cumulative Eligible Capital Balance				582,665
Current Year Deduction		582,665	x 7% =	40,787
Cumulative Eligible Capital - Closing Balance				541,878

Income Tax/PILs Workform for 2013 Filers

Schedule 13 Tax Reserves - Historical

Continuity of Reserves

Description	Historical Balance as per tax returns	Non-Distribution Eliminations	Utility Only
Capital Gains Reserves ss.40(1)			0
Tax Reserves Not Deducted for accounting purposes			
Reserve for doubtful accounts ss. 20(1)(l)			0
Reserve for goods and services not delivered ss. 20(1)(m)			0
Reserve for unpaid amounts ss. 20(1)(n)			0
Debt & Share Issue Expenses ss. 20(1)(e)			0
Other tax reserves			0
			0
			0
			0
			0
			0
Total	0	0	0
Financial Statement Reserves (not deductible for Tax Purposes)			
General Reserve for Inventory Obsolescence (non-specific)			0
General reserve for bad debts			0
Accrued Employee Future Benefits:	336,820		336,820
- Medical and Life Insurance			0
-Short & Long-term Disability			0
-Accmulated Sick Leave			0
- Termination Cost			0
- Other Post-Employment Benefits			0
Provision for Environmental Costs			0
Restructuring Costs			0
Accrued Contingent Litigation Costs			0
Accrued Self-Insurance Costs			0
Other Contingent Liabilities			0
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)			0
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)			0
Other			0
			0
			0
Total	336,820	0	336,820

Schedule 7-1 Loss Carry Forward - Historic

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance
Actual Historic			0

Net Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance
Actual Historic			0

Income Tax/PILs Workform for 2013 Filers

Adjusted Taxable Income - Historic Year

	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	Historic Wires Only
Income before PILs/Taxes	A	468,411		468,411
Additions:				
Interest and penalties on taxes	103			0
Amortization of tangible assets	104	1,053,169		1,053,169
Amortization of intangible assets	106			0
Recapture of capital cost allowance from Schedule 8	107			0
Gain on sale of eligible capital property from Schedule 10	108			0
Income or loss for tax purposes- joint ventures or partnerships	109			0
Loss in equity of subsidiaries and affiliates	110			0
Loss on disposal of assets	111			0
Charitable donations	112			0
Taxable Capital Gains	113			0
Political Donations	114			0
Deferred and prepaid expenses	116			0
Scientific research expenditures deducted on financial statements	118			0
Capitalized interest	119			0
Non-deductible club dues and fees	120			0
Non-deductible meals and entertainment expense	121	1,000		1,000
Non-deductible automobile expenses	122			0
Non-deductible life insurance premiums	123			0
Non-deductible company pension plans	124			0
Tax reserves deducted in prior year	125			0
Reserves from financial statements- balance at end of year	126	336,820		336,820
Soft costs on construction and renovation of buildings	127			0
Book loss on joint ventures or partnerships	205			0
Capital items expensed	206			0
Debt issue expense	208			0
Development expenses claimed in current year	212			0
Financing fees deducted in books	216			0
Gain on settlement of debt	220			0
Non-deductible advertising	226			0
Non-deductible interest	227			0
Non-deductible legal and accounting fees	228			0
Recapture of SR&ED expenditures	231			0
Share issue expense	235			0
Write down of capital property	236			0
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237			0
Other Additions				
Interest Expensed on Capital Leases	290			0
Realized Income from Deferred Credit Accounts	291			0
Pensions	292			0
Non-deductible penalties	293			0
Tax provision expense	294	125,438		125,438
Provincial ITCS related to PPA section 9 inclusion	295	4,097		4,097
ARO Accretion expense				0
Capital Contributions Received (ITA 12(1)(x))				0
Lease Inducements Received (ITA 12(1)(x))				0
Deferred Revenue (ITA 12(1)(a))				0
Prior Year Investment Tax Credits received				0
Amortization contained in other expenses		152,728		152,728

				0
				0
				0
				0
				0
				0
				0
				0
				0
Total Additions		1,673,252	0	1,673,252
Deductions:				
Gain on disposal of assets per financial statements	401	320		320
Dividends not taxable under section 83	402			0
Capital cost allowance from Schedule 8	403	1,212,578		1,212,578
Terminal loss from Schedule 8	404			0
Cumulative eligible capital deduction from Schedule 10	405	40,787		40,787
Allowable business investment loss	406			0
Deferred and prepaid expenses	409			0
Scientific research expenses claimed in year	411	219,502		219,502
Tax reserves claimed in current year	413			0
Reserves from financial statements - balance at beginning of year	414	308,029		308,029
Contributions to deferred income plans	416			0
Book income of joint venture or partnership	305			0
Equity in income from subsidiary or affiliates	306			0
Other deductions: (Please explain in detail the nature of the item)				
Interest capitalized for accounting deducted for tax	390			0
Capital Lease Payments	391			0
Non-taxable imputed interest income on deferral and variance accounts	392			0
	393			0
	394			0
ARO Payments - Deductible for Tax when Paid				0
ITA 13(7.4) Election - Capital Contributions Received				0
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds				0
Deferred Revenue - ITA 20(1)(m) reserve				0
Principal portion of lease payments				0
Lease Inducement Book Amortization credit to Income				0
Financing fees for tax ITA 20(1)(e) and (e.1)				0
				0
				0
				0
				0
				0
				0
				0
Total Deductions		1,781,216	0	1,781,216
Net Income for Tax Purposes		360,447	0	360,447
Charitable donations from Schedule 2	311			0
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320			0
Non-capital losses of preceding taxation years from Schedule 4	331			0
Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)*	332			0
Limited partnership losses of preceding taxation years from Schedule 4	335			0
TAXABLE INCOME		360,447	0	360,447

Income Tax/PILs Workform for 2013 Filers

PILs Tax Provision - Historic Year

Note: Input the actual information from the tax returns for the historic year.

						Wires Only	
Regulatory Taxable Income						$ 360,447	A
Ontario Income Taxes							
Income tax payable	**Ontario Income Tax**	11.75%	B	$ 42,345	C = A * B		
Small business credit	Ontario Small Business Threshold	$ 500,000	D				
	Rate reduction (negative)	7.25%	E	-$ 26,125	F = D * E		
Ontario Income tax						$ 16,220	J = C + F
Combined Tax Rate and PILs	Effective Ontario Tax Rate			4.50%	K = J / A		
	Federal tax rate			12.90%	L		
	Combined tax rate					17.40%	M = K + L
Total Income Taxes						$ 62,731	N = A * M
Investment Tax Credits						$ 46,511	O
Miscellaneous Tax Credits						$ 10,150	P
Total Tax Credits						$ 56,661	Q = O + P
Corporate PILs/Income Tax Provision for Historic Year						$ 6,070	R = N - Q

Schedule 8 CCA - Bridge Year

Class	Class Description	UCC Regulated Historic Year	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule (1/2 Additions Less Disposals)	Reduced UCC	Rate %	Bridge Year CCA	UCC End of Bridge Year
1	Distribution System - post 1987	$ 7,191,139	$ 108,735		$ 7,299,874	$ 54,368	$ 7,245,507	4%	$ 289,820	$ 7,010,054
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election				$ -	$ -	$ -	6%	$ -	$ -
2	Distribution System - pre 1988				$ -	$ -	$ -	6%	$ -	$ -
8	General Office/Stores Equip	$ 181,096	$ 16,531		$ 177,626	$ 8,266	$ 169,361	20%	$ 33,872	$ 143,754
10	Computer Hardware/ Vehicles	$ 603,298	$ 263,420		$ 866,718	$ 131,710	$ 735,008	30%	$ 220,502	$ 646,214
10.1	Certain Automobiles				$ -	$ -	$ -	30%	$ -	$ -
12	Computer Software	$ 526	$ 4,225		$ 4,750	$ 2,113	$ 2,638	100%	$ 2,638	$ 2,113
13 1	Lease # 1				$ -	$ -	$ -		$ -	$ -
13 2	Lease #2				$ -	$ -	$ -		$ -	$ -
13 3	Lease # 3				$ -	$ -	$ -		$ -	$ -
13 4	Lease # 4				$ -	$ -	$ -		$ -	$ -
14	Franchise				$ -	$ -	$ -		$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs				$ -	$ -	$ -	8%	$ -	$ -
42	Fibre Optic Cable				$ -	$ -	$ -	12%	$ -	$ -
43.1	Certain Energy-Efficient Electrical Generating Equipment				$ -	$ -	$ -	30%	$ -	$ -
43.2	Certain Clean Energy Generation Equipment				$ -	$ -	$ -	50%	$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04				$ -	$ -	$ -	45%	$ -	$ -
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)				$ -	$ -	$ -	30%	$ -	$ -
47	Distribution System - post February 2005	$ 9,208,802	$ 1,011,291		$ 10,220,093	$ 505,646	$ 9,714,448	8%	$ 777,156	$ 9,442,937
50	Data Network Infrastructure Equipment - post Mar 2007	$ 13,060			$ 13,060	$ -	$ 13,060	55%	$ 7,183	$ 5,877
52	Computer Hardware and system software				$ -	$ -	$ -	100%	$ -	$ -
95	CWIP				$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
	TOTAL	$ 17,177,917	$ 1,404,202	$ -	$ 18,582,119	$ 702,101	$ 17,880,018		$ 1,331,170	$ 17,250,949

Schedule 10 CEC - Bridge Year

Cumulative Eligible Capital				541,878
Additions				
Cost of Eligible Capital Property Acquired during Test Year				
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	x 1/2 =	0	
			0	0
Amount transferred on amalgamation or wind-up of subsidiary	0			0
Subtotal				541,878
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year				
Other Adjustments	0			
Subtotal	0	x 3/4 =		0
Cumulative Eligible Capital Balance				541,878
Current Year Deduction		541,878	x 7% =	37,931
Cumulative Eligible Capital - Closing Balance				503,947

Schedule 13 Tax Reserves - Bridge Year

Continuity of Reserves

				Bridge Year Adjustments				
Description	Historic Utility Only	Eliminate Amounts Not Relevant for Bridge Year	Adjusted Utility Balance	Additions	Disposals	Balance for Bridge Year	Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)	0		0			0	0	
Tax Reserves Not Deducted for accounting purposes								
Reserve for doubtful accounts ss. 20(1)(l)	0		0			0	0	
Reserve for goods and services not delivered ss. 20(1)(m)	0		0			0	0	
Reserve for unpaid amounts ss. 20(1)(n)	0		0			0	0	
Debt & Share Issue Expenses ss. 20(1)(e)	0		0			0	0	
Other tax reserves	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	0	0	0	0	0	0	0	0
Financial Statement Reserves (not deductible for Tax Purposes)								
General Reserve for Inventory Obsolescence (non-specific)	0		0			0	0	
General reserve for bad debts	0		0			0	0	
Accrued Employee Future Benefits:	336,820		336,820		352	336,468	-352	
- Medical and Life Insurance	0		0			0	0	
-Short & Long-term Disability	0		0			0	0	
-Accmulated Sick Leave	0		0			0	0	
- Termination Cost	0		0			0	0	
- Other Post-Employment Benefits	0		0			0	0	
Provision for Environmental Costs	0		0			0	0	
Restructuring Costs	0		0			0	0	
Accrued Contingent Litigation Costs	0		0			0	0	
Accrued Self-Insurance Costs	0		0			0	0	
Other Contingent Liabilities	0		0			0	0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	0		0			0	0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	0		0			0	0	
Other	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	336,820	0	336,820	0	352	336,468	-352	0

Income Tax/PILs Workform for 2013 Filers

Corporation Loss Continuity and Application

Schedule 7-1 Loss Carry Forward - Bridge Year

Non-Capital Loss Carry Forward Deduction	**Total**
Actual Historic	0
Application of Loss Carry Forward to reduce taxable income in Bridge Year	
Other Adjustments Add (+) Deduct (-)	
Balance available for use in Test Year	0
Amount to be used in Bridge Year	
Balance available for use post Bridge Year	0

Net Capital Loss Carry Forward Deduction	**Total**
Actual Historic	0
Application of Loss Carry Forward to reduce taxable income in Bridge Year	
Other Adjustments Add (+) Deduct (-)	
Balance available for use in Test Year	0
Amount to be used in Bridge Year	
Balance available for use post Bridge Year	0

Adjusted Taxable Income - Bridge Year

	T2S1 line #	Total for Regulated Utility
Income before PILs/Taxes	A	145,964
Additions:		
Interest and penalties on taxes	103	
Amortization of tangible assets	104	1,739,853
Amortization of intangible assets	106	
Recapture of capital cost allowance from Schedule 8	107	
Gain on sale of eligible capital property from Schedule 10	108	
Income or loss for tax purposes- joint ventures or partnerships	109	
Loss in equity of subsidiaries and affiliates	110	
Loss on disposal of assets	111	
Charitable donations	112	25,225
Taxable Capital Gains	113	
Political Donations	114	
Deferred and prepaid expenses	116	
Scientific research expenditures deducted on financial statements	118	
Capitalized interest	119	
Non-deductible club dues and fees	120	
Non-deductible meals and entertainment expense	121	1,000
Non-deductible automobile expenses	122	
Non-deductible life insurance premiums	123	
Non-deductible company pension plans	124	
Tax reserves deducted in prior year	125	0
Reserves from financial statements- balance at end of year	126	336,468
Soft costs on construction and renovation of buildings	127	
Book loss on joint ventures or partnerships	205	
Capital items expensed	206	
Debt issue expense	208	
Development expenses claimed in current year	212	
Financing fees deducted in books	216	
Gain on settlement of debt	220	
Non-deductible advertising	226	
Non-deductible interest	227	
Non-deductible legal and accounting fees	228	
Recapture of SR&ED expenditures	231	107,258
Share issue expense	235	
Write down of capital property	236	
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	

Income Tax/PILs Workform for 2013 Filers

Adjusted Taxable Income - Bridge Year

Other Additions		
Interest Expensed on Capital Leases	290	
Realized Income from Deferred Credit Accounts	291	
Pensions	292	
Non-deductible penalties	293	
Provision for income taxes - current	294	-19,068
Provision for income taxes - deferred	295	179,288
ARO Accretion expense		
Capital Contributions Received (ITA 12(1)(x))		
Lease Inducements Received (ITA 12(1)(x))		
Deferred Revenue (ITA 12(1)(a))		
Prior Year Investment Tax Credits received		
Amortization contained in other expenses		43,005
Total Additions		**2,413,029**
Deductions:		
Gain on disposal of assets per financial statements	401	645
Dividends not taxable under section 83	402	
Capital cost allowance from Schedule 8	403	1,331,170
Terminal loss from Schedule 8	404	
Cumulative eligible capital deduction from Schedule 10	405	37,931
Allowable business investment loss	406	
Deferred and prepaid expenses	409	
Scientific research expenses claimed in year	411	
Tax reserves claimed in current year	413	0
Reserves from financial statements - balance at beginning of year	414	336,820
Contributions to deferred income plans	416	
Book income of joint venture or partnership	305	
Equity in income from subsidiary or affiliates	306	
Other deductions: (Please explain in detail the nature of the item)		

Adjusted Taxable Income - Bridge Year

Interest capitalized for accounting deducted for tax	390	
Capital Lease Payments	391	
Non-taxable imputed interest income on deferral and variance accounts	392	
	393	
	394	
ARO Payments - Deductible for Tax when Paid		
ITA 13(7.4) Election - Capital Contributions Received		
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds		
Deferred Revenue - ITA 20(1)(m) reserve		
Principal portion of lease payments		
Lease Inducement Book Amortization credit to Income		
Financing fees for tax ITA 20(1)(e) and (e.1)		
Total Deductions		**1,706,567**
Net Income for Tax Purposes		**852,426**
Charitable donations from Schedule 2	311	25,225
Taxable dividends deductible under section 112 or 113, from Schedule 3 *(item 82)*	320	
Non-capital losses of preceding taxation years from Schedule 4	331	
Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)*	332	
Limited partnership losses of preceding taxation years from Schedule 4	335	
TAXABLE INCOME		**827,201**

PILS Tax Provision - Bridge Year

						Wires Only	
Regulatory Taxable Income						$ 827,201	A
Ontario Income Taxes							
Income tax payable	**Ontario Income Tax**	11.50%	B	$ 95,128	C = A * B		
Small business credit	Ontario Small Business Threshold	$ 500,000	D				
	Rate reduction	-7.00%	E	-$ 35,000	F = D * E		
Ontario Income tax						$ 60,128	J = C + F
Combined Tax Rate and PILs	Effective Ontario Tax Rate			7.27%	K = J / A		
	Federal tax rate			15.00%	L		
	Combined tax rate					22.27%	M = K + L
Total Income Taxes						$ 184,206	N = A * M
Investment Tax Credits							O
Miscellaneous Tax Credits							P
Total Tax Credits						$ -	Q = O + P
Corporate PILs/Income Tax Provision for Bridge Year						$ 184,206	R = N - Q

Note:

1. This is for the derivation of Bridge year PILs income tax expense and should not be used for Test year revenue requirement calculations.

Income Tax/PILs Workform for 2013 Filers

Schedule 8 CCA - Test Year

Class	Class Description	UCC Test Year Opening Balance	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule (1/2 Additions Less Disposals)	Reduced UCC	Rate %	Test Year CCA	UCC End of Test Year
1	Distribution System - post 1987	$ 7,010,054			$ 7,010,054	$ -	$ 7,010,054	4%	$ 280,402	$ 6,729,652
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	$ -			$ -	$ -	$ -	6%	$ -	$ -
2	Distribution System - pre 1988	$ -			$ -	$ -	$ -	6%	$ -	$ -
8	General Office/Stores Equip	$ 143,754	115,000		$ 258,754	$ 57,500	$ 201,254	20%	$ 40,251	$ 218,503
10	Computer Hardware/ Vehicles	$ 848,214	202,000		$ 848,214	$ 101,000	$ 747,214	30%	$ 224,164	$ 624,050
10.1	Certain Automobiles	$ -			$ -	$ -	$ -	30%	$ -	$ -
12	Computer Software	$ 2,113	105,000		$ 107,113	$ 52,500	$ 54,613	100%	$ 54,613	$ 52,500
13 1	Lease # 1	$ -			$ -	$ -	$ -		$ -	$ -
13 2	Lease #2	$ -			$ -	$ -	$ -		$ -	$ -
13 3	Lease # 3	$ -			$ -	$ -	$ -		$ -	$ -
13 4	Lease # 4	$ -			$ -	$ -	$ -		$ -	$ -
14	Franchise	$ -			$ -	$ -	$ -		$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than B	$ -			$ -	$ -	$ -	8%	$ -	$ -
42	Fibre Optic Cable	$ -			$ -	$ -	$ -	12%	$ -	$ -
43.1	Certain Energy-Efficient Electrical Generating Equipment	$ -			$ -	$ -	$ -	30%	$ -	$ -
43.2	Certain Clean Energy Generation Equipment	$ -			$ -	$ -	$ -	50%	$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04	$ -			$ -	$ -	$ -	45%	$ -	$ -
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ -			$ -	$ -	$ -	30%	$ -	$ -
47	Distribution System - post February 2005	$ 9,442,937	1,601,208		$ 11,044,145	$ 800,604	$ 10,243,541	8%	$ 819,483	$ 10,224,662
50	Data Network Infrastructure Equipment - post Mar 2007	$ 5,877			$ 5,877	$ -	$ 5,877	55%	$ 3,232	$ 2,645
52	Computer Hardware and system software	$ -			$ -	$ -	$ -	100%	$ -	$ -
95	CWIP	$ -			$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
	TOTAL	$ 17,250,949	$ 2,023,208	$ -	$ 19,274,157	$ 1,011,604	$ 18,262,553		$ 1,422,145	$ 17,852,011

Schedule 10 CEC - Test Year

Cumulative Eligible Capital					503,947
Additions					
Cost of Eligible Capital Property Acquired during Test Year		0			
Other Adjustments		0			
	Subtotal	0	x 3/4 =	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002		0	x 1/2 =	0	
				0	0
Amount transferred on amalgamation or wind-up of subsidiary		0			0
	Subtotal				503,947
Deductions					
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year		0			
Other Adjustments		0			
	Subtotal	0	x 3/4 =		0
Cumulative Eligible Capital Balance					503,947
Current Year Deduction (Carry Forward to Tab "Test Year Taxable Income")			503,947	x 7% =	35,276
Cumulative Eligible Capital - Closing Balance					468,671

Income Tax/PILs Workform for 2013 Filers

Schedule 13 Tax Reserves - Test Year

Continuity of Reserves

Description	Bridge Year	Eliminate Amounts Not Relevant for Bridge Year	Adjusted Utility Balance	Test Year Adjustments: Additions	Test Year Adjustments: Disposals	Balance for Test Year	Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)	0		0			0	0	
Tax Reserves Not Deducted for accounting purposes								
Reserve for doubtful accounts ss. 20(1)(l)	0		0			0	0	
Reserve for goods and services not delivered ss. 20(1)(m)	0		0			0	0	
Reserve for unpaid amounts ss. 20(1)(n)	0		0			0	0	
Debt & Share Issue Expenses ss. 20(1)(e)	0		0			0	0	
Other tax reserves	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	0	0	0	0	0	0	0	0
Financial Statement Reserves (not deductible for Tax Purposes)								
General Reserve for Inventory Obsolescence (non-specific)	0		0			0	0	
General reserve for bad debts	0		0			0	0	
Accrued Employee Future Benefits:	336,468		336,468	18,461		354,929	18,461	
- Medical and Life Insurance	0		0			0	0	
-Short & Long-term Disability	0		0			0	0	
-Accmulated Sick Leave	0		0			0	0	
- Termination Cost	0		0			0	0	
- Other Post-Employment Benefits	0		0			0	0	
Provision for Environmental Costs	0		0			0	0	
Restructuring Costs	0		0			0	0	
Accrued Contingent Litigation Costs	0		0			0	0	
Accrued Self-Insurance Costs	0		0			0	0	
Other Contingent Liabilities	0		0			0	0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	0		0			0	0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	0		0			0	0	
Other	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	336,468	0	336,468	18,461	0	354,929	18,461	0

Income Tax/PILs Workform for 2013 Filers

Schedule 7-1 Loss Carry Forward - Test Year

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance
Actual/Estimated Bridge Year			0
Application of Loss Carry Forward to reduce taxable income in 2005			0
Other Adjustments Add (+) Deduct (-)			0
Balance available for use in Test Year	0	0	0
Amount to be used in Test Year			0
Balance available for use post Test Year	0	0	0

Net Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance
Actual/Estimated Bridge Year			0
Application of Loss Carry Forward to reduce taxable income in 2005			0
Other Adjustments Add (+) Deduct (-)			0
Balance available for use in Test Year	0	0	0
Amount to be used in Test Year			0
Balance available for use post Test Year	0	0	0

Taxable Income - Test Year

	T2 S1 line #	Test Year Taxable Income
Net Income Before Taxes		727,491
Additions:		
Interest and penalties on taxes	103	
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104	
Amortization of intangible assets *2-4 ADJUSTED ACCOUNTING DATA P490*	106	1,102,871
Recapture of capital cost allowance from Schedule 8	107	
Gain on sale of eligible capital property from Schedule 10	108	
Income or loss for tax purposes- joint ventures or partnerships	109	
Loss in equity of subsidiaries and affiliates	110	
Loss on disposal of assets	111	
Charitable donations	112	
Taxable Capital Gains	113	
Political Donations	114	
Deferred and prepaid expenses	116	
Scientific research expenditures deducted on financial statements	118	
Capitalized interest	119	
Non-deductible club dues and fees	120	
Non-deductible meals and entertainment expense	121	1,000
Non-deductible automobile expenses	122	
Non-deductible life insurance premiums	123	
Non-deductible company pension plans	124	
Tax reserves beginning of year	125	0
Reserves from financial statements- balance at end of year	126	354,929
Soft costs on construction and renovation of buildings	127	
Book loss on joint ventures or partnerships	205	
Capital items expensed	206	
Debt issue expense	208	
Development expenses claimed in current year	212	
Financing fees deducted in books	216	
Gain on settlement of debt	220	
Non-deductible advertising	226	
Non-deductible interest	227	
Non-deductible legal and accounting fees	228	
Recapture of SR&ED expenditures	231	
Share issue expense	235	
Write down of capital property	236	

Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	
Other Additions: (please explain in detail the nature of the item)		
Interest Expensed on Capital Leases	290	
Realized Income from Deferred Credit Accounts	291	
Pensions	292	
Non-deductible penalties	293	
	294	
	295	
	296	
	297	
ARO Accretion expense		
Capital Contributions Received (ITA 12(1)(x))		
Lease Inducements Received (ITA 12(1)(x))		
Deferred Revenue (ITA 12(1)(a))		
Prior Year Investment Tax Credits received		
Total Additions		**1,458,800**
Deductions:		
Gain on disposal of assets per financial statements	401	
Dividends not taxable under section 83	402	
Capital cost allowance from Schedule 8	403	1,422,145
Terminal loss from Schedule 8	404	
Cumulative eligible capital deduction from Schedule 10 CEC	405	35,276
Allowable business investment loss	406	
Deferred and prepaid expenses	409	
Scientific research expenses claimed in year	411	
Tax reserves end of year	413	0
Reserves from financial statements - balance at beginning of year	414	336,468
Contributions to deferred income plans	416	
Book income of joint venture or partnership	305	
Equity in income from subsidiary or affiliates	306	
Other deductions: (Please explain in detail the nature of the item)		
Interest capitalized for accounting deducted for tax	390	
Capital Lease Payments	391	

Non-taxable imputed interest income on deferral and variance accounts	392	
	393	
	394	
	395	
	396	
	397	
ARO Payments - Deductible for Tax when Paid		
ITA 13(7.4) Election - Capital Contributions Received		
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds		
Deferred Revenue - ITA 20(1)(m) reserve		
Principal portion of lease payments		
Lease Inducement Book Amortization credit to income		
Financing fees for tax ITA 20(1)(e) and (e.1)		
Total Deductions		**1,793,890**
NET INCOME FOR TAX PURPOSES		**392,402**
Charitable donations	311	
Taxable dividends received under section 112 or 113	320	
Non-capital losses of preceding taxation years from Schedule 7-1	331	
Net-capital losses of preceding taxation years (Please show calculation)	332	
Limited partnership losses of preceding taxation years from Schedule 4	335	
REGULATORY TAXABLE INCOME		**392,402**

Income Tax/PILs Workform for 2013 Filers

PILs Tax Provision - Test Year

							Wires Only	
Regulatory Taxable Income							$ 392,402	A
Ontario Income Taxes								
Income tax payable	**Ontario Income Tax**	4.50%	B	$	17,658	C = A * B		
Small business credit	Ontario Small Business Threshold	$ -	D					
	Rate reduction	-7.00%	E	$	-	F = D * E		
Ontario Income tax							$ 17,658	J = C + F
Combined Tax Rate and PILs	Effective Ontario Tax Rate				4.50%	K = J / A		
	Federal tax rate				11.00%	L		
	Combined tax rate						15.50%	M = K + L
Total Income Taxes							$ 60,822	N = A * M
Investment Tax Credits								O
Miscellaneous Tax Credits								P
Total Tax Credits							$ -	Q = O + P
Corporate PILs/Income Tax Provision for Test Year							$ 60,822	R = N - Q
Corporate PILs/Income Tax Provision Gross Up [1]					84.50%	S = 1 - M	$ 11,157	T = R / S - R
Income Tax (grossed-up)							$ 71,979	U = R + T

Note:

1. This is for the derivation of revenue requirement and should not be used for sufficiency/deficiency calculations.

4-Energy Probe-33

Ref: Exhibit 4, Tab 4, Schedule 8

Please confirm that Collus PowerStream does not have any employees that qualify for the Ontario Apprenticeship tax credit, federal job training tax credit, or the Ontario Co-op Education tax credit. If this cannot be confirmed, please provide the number of employees that qualify for each credit in 2013.

Response

Yes, we confirm that Collus PowerStream does not have any employees that qualify for the Ontario Apprenticeship tax credit, federal job training tax credit, or the Ontario Co-op Education tax credit.

4-Energy Probe-34

Ref: Exhibit 4, Tab 6, Schedule 1

Has Collus PowerStream included any costs associated with the Board of Directors of any of the corporations shown in the diagram on page 1? If yes, please quantify and explain the basis upon which those costs are allocated to the associated companies.

Response

No, Collus PowerStream has not included any costs associated with the Board of Directors of any of the corporations shown in the diagram on page 1.

EXHIBIT 5 - COST OF CAPITAL AND RATE OF RETURN

5-Energy Probe-35

Ref: Exhibit 5, Tab 1, Schedule 1

a) **Please confirm that the Board's Cost of Capital Parameter Updates for 2013 Cost of Service Applications letter issued on February 14, 2013 is applicable for the 2013 COS application of Collus PowerStream.**

b) **Please indicate why Collus PowerStream "will update for the most current approved cost of capital parameters" prior to the finalization of the Tariff of Rates and Charges?**

c) **Please explain the difference in the long-term debt rate for 2013 shown in Table 1 of 4.12% and the figure of 4.05% shown in Tables 2 and 3.**

Response:

a) Yes we can confirm that the Boards Cost of Capital Parameters for 2013 cost of Service Applications issued on February 14, 2013 were used in the 2013 Collus PowerStream application.

b) Collus PowerStream will update for the most current cost of capital parameters at the time of the Board Decision. It is a filing requirement that such a statement be included in the evidence (Reference Chapter 2, Section 2.8 of the OEB Filing Requirements).

c) C - Table 1 is the Long Term Cost of Debt as prescribed per the OEB's Cost of Capital Parameters (used for non-arm’s length debt such as the Promissory Note with the Town of Collingwood), Tables 2 and 3 are the Weighted Average Debt rate which includes two government loan debt instruments with "real" interest rates. The calculation is shown on Table 2 in E5/T1/S1 pg. 2.

5-Energy Probe-36

Ref: Exhibit 5, Tab 1, Schedule 1, Appendix A

a) Please confirm that Collus PowerStream has the right to repay the promissory note from the Town of Collingwood (principal and accrued interest) at any time.

b) Has Collus PowerStream investigated replacing the Town of Collingwood promissory note with a lower cost loan from a third party? If not, why not? If yes, please provide details of available replacement financing and indicate why Collus PowerStream has not opted to replace the promissory note.

Response

a) Yes, Collus PowerStream has the right to repay the promissory note from the Town of Collingwood (principal and accrued interest) at any time without notice or bonus.

b) Yes, Collus PowerStream is currently investigating replacing the Town of Collingwood promissory note with a lower cost loan from a third party.

The original Town of Collingwood loan was 7.25% which based on the "Share Purchase Agreement" reduced to 5.58% on January 1, 2013 and reduces again January 1, 2014 to an interest rate as is deemed compliant with the OEB regulations. The deemed long-term debt rate is 4.03% per the November 15th, 2012 "Cost of Capital Parameter Updates for 2013 Cost of Service Applications for Rates Effective January 1, 2013".

Currently, $1.7m in undrawn funds are available from Infrastructure Ontario to be repurposed to repay the Town of Collingwood promissory note. The current lending rates for Infrastructure Ontario are listed below. Collus PowerStream's board of directors is currently in the process of investigating the option to replace the promissory note.

Lending Rates: Local Distribution Companies

Indicative Lending Rates as of August 8, 2013**

Term	Construction	Serial	Amortizer
1 Month	1.79%	-	-
5 Year	-	2.41%	2.51%
10 Year	-	3.30%	3.40%
15 Year	-	3.76%	3.86%
20 Year	-	4.05%	4.15%
25 Year	-	4.24%	4.34%
30 Year	-	4.35%	4.45%

5-SEC-19

[Ex.5/1/1/p.1]
Please provide the Applicant's actual ROE for each year between 2009-2012.

Response:

Table SEC-19-1 below provides the actual ROE for 2009 to 2012.

Table SEC-19-1: Actual ROE 2009 to 2012

Return on Equity (ROE)	**2009**	**2010**	**2011**	**2012**
Net income (see A below)	$ 480,405	$ 707,000	$ 456,354	$ 325,236
Equity (see B below)	$ 6,161,311	$ 6,653,868	$ 7,235,133	$ 7,457,449
ROE = A/B	**7.80%**	**10.63%**	**6.31%**	**4.36%**
(A) Net Income after Tax	**2009**	**2010**	**2011**	**2012**
Revenues				
Distribution Revenue	$ 5,126,519	$ 5,437,389	$ 5,592,609	$ 5,456,009
Smart Meter revenue	$ -	$ -	$ -	$ 1,402,131
Other revenue	$ 488,295	$ 556,865	$ 423,378	$ 465,569
Total Revenue	**$ 5,614,814**	**$ 5,994,254**	**$ 6,015,987**	**$ 7,323,709**
Expenses				
OM&A	$ 3,850,193	$ 3,995,851	$ 4,073,086	$ 4,843,305
Depreciation and Amortization	$ 1,004,161	$ 967,205	$ 1,053,169	$ 1,739,853
Interest	$ 179,149	$ 249,634	$ 285,649	$ 434,367
Taxes - current	$ 100,906	$ 74,564	$ 147,729	$ (19,052)
Total Expenses	**$ 5,134,409**	**$ 5,287,254**	**$ 5,559,633**	**$ 6,998,473**
Net Income (A)	**$ 480,405**	**$ 707,000**	**$ 456,354**	**$ 325,236**
(B) Equity				
Rate base	$ 15,403,277	$ 16,634,671	$ 18,087,832	$ 18,643,622
Equity = 40% of Rate base	**$ 6,161,311**	**$ 6,653,868**	**$ 7,235,133**	**$ 7,457,449**

5-SEC-20

[Ex.5/1/1/p.2] Please provide a copy of all outstanding debt instruments not already included in the evidence.

Response

Collus PowerStream has no outstanding debt instruments not included in the evidence.

5.0 - VECC- 34

Reference: Exhibit 5, Tab 1

a) Please provide the actual and deemed rates of return on equity and capital for each of the years 2009 through 2012.

Response:

a) Table VECC 34-1 contains a calculation of the actual and deemed rates of return on equity and capital for the years 2009 through 2012. The deemed rates are taken from Collus PowerStream's approved 2009 Cost of Service rate application (EB-2008-0226).

Table VECC 34-1: Return on Equity and Capital 2009 to 2012

Return on Equity (ROE)	2009	2010	2011	2012
Net income (from A)	$ 480,405	$ 707,000	$ 456,354	$ 325,236
Shareholder Equity (from C)	$ 10,158,882	$ 10,582,602	$ 11,016,175	$ 9,141,377
Actual Return on Equity (= A÷C)	**4.73%**	**6.68%**	**4.14%**	**3.56%**
Deemed ROE 2009 COS	**8.01%**	**8.01%**	**8.01%**	**8.01%**
Return on Capital	**2009**	**2010**	**2011**	**2012**
Average Debt (D below)	$ 1,737,721	$ 3,160,170	$ 4,510,170	$ 7,441,300
Average Shareholder Equity (C below)	$ 10,158,882	$ 10,582,602	$ 11,016,175	$ 9,141,377
(1) Average Capital (Debt + Equity)	$ 11,896,603	$ 13,742,772	$ 15,526,345	$ 16,582,677
Actual Interest (below)	$ 179,149	$ 249,634	$ 285,649	$ 434,367
Net income after Tax (A below)	$ 480,405	$ 707,000	$ 456,354	$ 325,236
(2) Return on Capital (Interest + Income)	$ 659,554	$ 956,634	$ 742,003	$ 759,603
Actual return on capital % (= (2)÷(1))	**5.54%**	**6.96%**	**4.78%**	**4.58%**
Deemed Cost of Capital 2009 COS	**7.01%**	**7.01%**	**7.01%**	**7.01%**

Table VECC 34-1 continued:

(A) Net Income after Tax	**2009**	**2010**	**2011**	**2012**
Revenues				
Distribution Revenue	$ 5,126,519	$ 5,437,389	$ 5,592,609	$ 5,456,009
Smart Meter revenue	$ -	$ -	$ -	$ 1,402,131
Other revenue	$ 488,295	$ 556,865	$ 423,378	$ 465,569
Total Revenue	**$ 5,614,814**	**$ 5,994,254**	**$ 6,015,987**	**$ 7,323,709**
Expenses				
OM&A	$ 3,850,193	$ 3,995,851	$ 4,073,086	$ 4,843,305
Depreciation and Amortization	$ 1,004,161	$ 967,205	$ 1,053,169	$ 1,739,853
Interest	$ 179,149	$ 249,634	$ 285,649	$ 434,367
Taxes - current	$ 100,906	$ 74,564	$ 147,729	$ (19,052)
Total Expenses	**$ 5,134,409**	**$ 5,287,254**	**$ 5,559,633**	**$ 6,998,473**
Net Income (A)	**$ 480,405**	**$ 707,000**	**$ 456,354**	**$ 325,236**
(B) Deemed Equity	**2009**	**2010**	**2011**	**2012**
Rate base	$ 15,403,277	$ 16,634,671	$ 18,087,832	$ 18,643,622
Equity = 40% of Rate base	**$ 6,161,311**	**$ 6,653,868**	**$ 7,235,133**	**$ 7,457,449**
(C) Shareholder Equity (Financials)	**2009**	**2010**	**2011**	**2012**
Opening	$ 9,934,531	$ 10,383,233	$ 10,781,970	$ 11,250,380
Closing	$ 10,383,233	$ 10,781,970	$ 11,250,380	$ 7,032,373
Average	**$ 10,158,882**	**$ 10,582,602**	**$ 11,016,175**	**$ 9,141,377**
(D) Debt	**2009**	**2010**	**2011**	**2012**
Opening	$ 2,827,523	$ 1,710,170	$ 4,610,170	$ 4,410,170
Closing	$ 1,710,170	$ 4,610,170	$ 4,410,170	$ 10,472,430
Average	**$ 1,737,721**	**$ 3,160,170**	**$ 4,510,170**	**$ 7,441,300**

EXHIBIT 7 – COST ALLOCATION

7.0-Staff-27

Ref: E4/T4/S7, p. 4; CA Model, worksheet I-3, cell E430 (Account 5705) – Allocation of Amortization

Depreciation is described in Exhibit 4 totaling $1,102,871. In worksheet I-3, the amount of $30,000 is entered at cell E430, which as a result is allocated as a component of account 5705 'Amortization Expense – PP&E'. With this amount, the allocated total is $940,824.

a) Please state which is the correct cost to be used in the revenue requirement and for allocation to classes.
b) Please explain what the $30,000 component refers to, providing a reference if applicable to where the cost is described in the application.
c) Please confirm that the $30,000 amount is not attributable to account 1575 or 1576.

Response

a) The correct amount to be allocated to the customer classes is $$940,824. This represents the net depreciation expense after re-allocation of vehicle depreciation of $192,047 to other cost categories plus the addition of $30,000 in derecognition costs.

b) The $30,000 component on E4/T4/S7 is a depreciation adjustment for derecognition expense. It has been determined by the following calculation and rounded down to $30,000. Reference to derecognition or disposal can be found at E6/T1/S1 page 6 of 11, Table 7. Another reference to it can be found at E2/T2/S1 page 5 of 5, Table 7.

Derecognition Expense Estimate

	PowerStream	COLLUS
2013 Rate Base - Average Net Fixed Assets (NFA)	$ 719,273,918	$ 15,928,927
Derecognition Expense	$ 1,400,000	$ 31,004
Derecognition as % of NFA	0.19%	0.19%

c) Collus PowerStream confirms the $30,000 is not attributable to account 1575 or 1576, as the change in accounting is concurrent with the rebasing of rates.

7.0-Staff-28

Ref: E7/T1/S1, Table 5; Appendix 2-P; CA Model worksheet O-1 – Revenue to Cost Ratios

The total revenue requirement matches in these two references, at $6,981,397, but the amounts allocated to the respective classes do not match. In particular, the General Service > 50 kW class revenue requirement in Table A of Appendix 2-P is $1,181,819 whereas the class revenue requirement in the CA model is $957,151. A result is that the status quo revenue to cost ratio of that class in Table C of Appendix 2-P is 94.23%, whereas in the CA model it is 115.80%

a) Please confirm that the status quo ratios in Exhibit 7 and the CA model should be used, and that Appendix 2-P should be disregarded as filed.
b) If the statement in part a) cannot be confirmed, please file a revised CA model and a revised Table 5 in Exhibit 7.
c) If the status quo ratios in Exhibit 7 and the cost allocation model are correct, please provide an updated version of Appendix 2-P.

Response

a) Collus PowerStream confirms the information included in the submitted application document is correct where the class revenue requirement for the > 50 kW class is $957,151 and the proposed revenue to cost ratio of that class is 115.80%.
b) N/A
c) The correct version of Appendix 2-P was provided in Exhibit 7 or the submitted application, however, an incorrect Excel version was filed.

Appendix 2-P

Cost Allocation

Please complete the following four tables.

a) Allocated Costs

Classes	**Costs Allocated from Previous Study (COLLUS Power 2009)**	**%**	**Costs Allocated in Test Year (2013) Study (Column 7A)**	%
Residential	$ 3,545,358	67.06%	$ 4,514,411	64.66%
GS < 50 kW	$ 798,452	15.10%	$ 1,305,367	18.70%
GS > 50 kW	$ 342,951	6.49%	$ 957,151	13.71%
Large User	$ 546,816	10.34%	$ -	0.00%
Street Lighting	$ 38,137	0.72%	$ 200,030	2.87%
Sentinel Lighting	$ -	0.00%	$ -	0.00%

Unmetered Scattered Load (USL)	$ 14,997	0.28%	$ 4,438	0.06%
Total	$ 5,286,711	100.00%	$ 6,981,397	100.00%

Notes

Customer Classification

Host Distributors: Provide information on embedded distributor(s) as a separate class, even if your proposal is to bill the embedded distributor(s) as (a) General Service customer(s).

If proposed rate classes differ from those in place in the previous Cost Allocation study, modify the rate classes to match the current application as closely as possible.

Class Revenue Requirements
If using the Board-issued model, enter data from Worksheet O-1, row **40** in the 2012 model.

For the Embedded Distributor(s), the Service Revenue Requirement does not include Account 4750 - Low Voltage (LV) Costs

Exclude costs in deferral and variance accounts.

Include Smart Meter costs only to the extent that they are being included in Rate Base and Revenue Requirement (i.e. being transferred from accounts 1555 and 1556 as a result of a prudence review).

b) Calculated Class Revenues

Classes (same as previous table)	**Column 7B** **Load Forecast (LF) X current approved rates**	**Column 7C** **LF X current approved rates X (1 + d)**	**Column 7D** **LF X proposed rates**	**Column 7E** **Miscellaneous Revenue**
Residential	$ 3,542,885	$ 4,135,938	$ 4,135,938	$ 315,025
GS < 50 kW	$ 903,699	$ 1,054,972	$ 1,069,252	$ 107,464
GS > 50 kW	$ 925,812	$ 1,080,787	$ 1,080,787	$ 27,578
Large User	$ -	$ -	$ -	$ -
Street Lighting	$ 201,955	$ 235,761	$ 224,771	$ 15,258
Sentinel Lighting	$ -	$ -	$ -	$ -
Unmetered Scattered Load (USL)	$ 7,144	$ 8,340	$ 5,050	$ 276
Total	$ 5,581,495	$ 6,515,797	$ 6,515,797	$ 465,600.00
	line 18	*line 23*	*As per Rate model*	*line 19*

Notes:

Columns
7B to 7D

LF means Load Forecast of Annual Billing Quantities (i.e. customers or connections X 12, **and** kWh or kW, as applicable)

Exclude revenue from rate adders and rate riders. For Embedded Distributor(s): exclude revenue in account 4075.

Columns 7C and 7D:

Column total in each column should equal the Base Revenue Requirement.

For Embedded Distributor(s), Base Revenue Requirement does not include Account 4750 - Low Voltage Costs

Column
7C:

The Board cost allocation model calculates "1+d" in worksheet O-1, cell C21. "d" is defined as Revenue Deficiency/ Revenue at Current Rates.

Column 7E:

If using the Board-issued Cost Allocation model, enter Miscellaneous Revenue as it appears in Worksheet O-1, row 19.

c) Rebalancing Revenue-to-Cost (R/C) Ratios

Class	Previously Approved Ratios	Status Quo Ratios	Proposed Ratios	Policy Range
	2011	(7C + 7E) / (7A)	(7D + 7E) / (7A)	
	%	%	%	%
Residential	104.4	98.6	98.6	85 - 115
GS < 50 kW	99.7	89.1	90.1	80 - 120
GS > 50 kW	80.0	115.8	115.8	80 - 120
Large User				85 - 115
Street Lighting	70.0	125.5	120.0	70 - 120
Sentinel Lighting				80 - 120
Unmetered Scattered Load (USL)	87.8	194.1	120.0	80 - 120

Notes:

Previously Approved Revenue-to-Cost Ratios

For applicants that have had rates adjusted only under IRM 2, the Most Recent Year is 2006, and the applicant should enter the ratios from their Informational Filing.

Status Quo Ratios

The Board's updated Cost Allocation Model yields the Status Quo Ratios in Worksheet O-1.

Status Quo means "No Rebalancing" or "Before Rebalancing".

d) Proposed Revenue-to-Cost Ratios

Class	Proposed Revenue-to-Cost Ratios			Policy Range
	2012	2013	2014	
	%	%	%	%
Residential	98.59	98.59	98.6	85 - 115
GS < 50 kW	90.14	90.14	90.1	80 - 120
GS > 50 kW	115.80	115.80	115.8	80 - 120
Large User				85 - 115
Street Lighting	120.00	120.00	120.0	70 - 120
Sentinel Lighting				80 - 120
Unmetered Scattered Load (USL)	120.00	120.00	120.0	80 - 120

The applicant should complete Table (d) if it is applying for approval of a revenue to cost ratio in 2012 that is outside the Board's policy range for any customer class. Table (d) will show the information that the distributor would likely enter in the IRM model) in 2013. In 2012 Table (d), enter the planned ratios for the classes that will be 'Change' and 'No Change' in 2013 (in the current Revenue Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision – Cost Revenue Adjustment', column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

7.0-VECC – 35

Reference: Exhibit 7, Tab 1, Schedule 1, page 5

a) Based on COLLUS' Conditions of Service, are any its customer classes required to provide (and maintain) their own "service assets"? If so, which ones and for how long has this requirement been in place?

Response

a) No customer class is required to provide and maintain their own service assets. Customers requiring transformers greater than 500 kVa are customer owned and therefore receive the transformer allowance.

7.0-VECC – 36

Reference: Cost Allocation Model, Sheet I7.2

a) Please explain why the meter reading weighting factor for GS>50 is 0.38 relative to a value of 1.0 for Residential and GS<50.

Response

a) Collus PowerStream is of the opinion the costs of collecting and verifying smart meter data for the residential and general service classes exceeds the cost of the other classes. This may change as LDCs become more comfortable with the smart meter processes but for this rate application Collus PowerStream supports the weightings provided and wishes to maintain them as filed.

EXHIBIT 8 – RATE DESIGN

8.0-Staff-29

Ref: E3/T2/S1, p. 1, Table 1 and p. 4, Table 6; E8/T1/S2, p. 1, Table 1 – Fixed/Variable split

a) Please provide a table that shows how the revenue amounts in the first two columns of Table 1 (Exhibit 8) are derived from billing loads in Exhibit 3 (Tables 1 and 6)

Response

a)

	Customers / Connections	Volumes	Metric	2012 Approved Rates without Smart meter and Low Voltage		Annual Volumetric	Annual Fixed
Residential	14,233	119,926,353	kWh	$ 0.0170	$ 9.00	$ 2,038,748	$ 1,537,110
GS < 50 kW	1,717	47,835,746	kWh	$ 0.0113	$ 17.98	$ 540,544	$ 370,496
GS 50-2,999 kW	114	348,761	kW	$ 2.6400	$ 114.02	$ 920,728	$ 155,979
USL	30	421,186	kWh	$ 0.0177	$ -	$ 7,455	$ -
Street Lighting	3,045	6,144	kW	$ 14.0054	$ 3.14	$ 86,053	$ 114,729
						$ 3,593,529	**$ 2,178,315**

8.0-Staff-30

Ref: E1/T1/S2, Appendix A and E8/T1/S9, Table 2 – Revenue Reconciliation

The proposed volumetric rates in Exhibit 8 and in appendix 2-V appear to be inconsistent in Collus PowerStream's proposed tariff in Exhibit 1 and in the Bill Impact calculations in Appendix 2-W.

a) Please state which volumetric rates are being proposed by Collus PowerStream, and if necessary please file a revised calculation of revenue (including Appendix 2-V).

Response

a) Table 2 of E8/T1/S9 provides a combined distribution and low voltage volumetric rate for each class. The following volumetric rates are being proposed by Collus PowerStream:

	Distribution	Low Voltage	Combined
Residential	$ 0.0203	$0.0017	$ 0.0220
GS <50 kW	$ 0.0138	$0.0015	$ 0.0153
GS 50-2,999 kW	$ 3.0998	$0.5584	$ 3.6582
USL	$ 0.0125	$0.0015	$ 0.0140
Street Lighting	$15.3221	$0.4317	$15.7538

The proposed tariff in Exhibit 1 is correct in the submitted application.

8.0-Staff-31

Ref: E2/T4/S1, Table 3; CA model, account 4716; E8/T1/S3 and RTSR model – Transmission Costs

The cost projections used in the forecast cost of power as a component of Working Capital in Exhibit 2 appear to not match the forecast in Exhibit 8 (and in the RTSR Model) to derive COLLUS's proposed RTSRs. In particular, the forecast cost of Transmission Connection in Exhibit 2 Table 3 and in the CA model is $105,506, whereas in the RTSR model the forecast wholesale cost is $39,549 for line connection plus $1,006,065 for transformation.

a) Please state which cost forecast is correct, and provide any necessary revisions to the applicable model and exhibit.

Response

a) The cost of power model in Exhibit 2, Tab 4, Schedule 1, Table 3 required revisions to Commodity (RPP), Commodity (Spot), Global Adjustment and Transmission Transformation – HONI charges. As a result the forecasted transmission connection charges from Exhibit 2, Tab 4, Schedule 1, Table 3 were revised to $915,259 based on forecasted kW charges as compared to those in the RTSR model of $1,006,065 using historic 2011 kW charges.

   See 2-Energy Probe-17 for updated Table 3.

8-Energy Probe-37

Ref: Exhibit 8, Tab 1, Schedule 2

Please explain why Collus PowerStream is not proposing to raise the USL monthly service charge to the floor value of $0.46, as shown in Table 2.

Response

Collus PowerStream agrees that under the Board's cost allocation methodology it would be appropriate to adjust the monthly service charge to the floor value of $0.46. This is a minor matter which does not affect the allocation of revenue between classes. Collus PowerStream proposes that the USL monthly service charge be increased to the floor value in the draft rate order.

8.0-VECC – 37

Reference: Exhibit 8, Tab 1, Schedule 2, pages 1-2

a) Please confirm that COLLUS is not proposing to maintain the fixed/variable split for the GS>50 class (as suggested on page 1), but rather maintain the fixed charge at the 2012 value of $114.02 (as described on page 2).

Response

a) Since the current Board approved fixed charge is $114.02 Collus PowerStream has proposed the fixed rate be maintained at $114.02 versus reducing it to the ceiling of $78.80 as calculated by the Cost Allocation model. Stating on page 1 that all classes would maintain their current fixed variable split was made in error and should have read “all classes with the exception of the GS>50 class will maintain their existing fixed variable split”.

8.0-VECC – 38

Reference: Exhibit 8, Tab 1, Schedule 7

a) What is the basis for the forecast kW values used in Table 1?

b) What were COLLUS actual LV charges from HON for 2012?

Response

a) Collus PowerStream calculated historic ratios using 2 year average, 2010 and 2011 actuals, for Total kWh/System kW (0.184%), System line/System kW (8.064%) and System Transformation/System kW (100.04%) and used those ratios to calculate the Hydro One Low Voltage kW from the load forecasted total purchases.

b) Collus PowerStream low voltage charges for 2012 were as follows;

Month	kW
Jan-12	57,895
Feb-12	55,338
Mar-12	51,546
Apr-12	44,595
May-12	48,952
Jun-12	57,564
Jul-12	57,813
Aug-12	49,868
Sep-12	47,150
Oct-12	41,906
Nov-12	45,145
Dec-12	49,666

8-Energy Probe-38

Ref: Exhibit 8, Tab 1, Schedule 8

Please update Table 1 to include actual data for 2012. Please also calculate the 5-year average using data from 2008 through 2012.

Response

		Historical Years						5-Year Average
		2007	2008	2009	2010	2011	2012	2008-2012
	Losses Within Distributor's System							
A(1)	"Wholesale" kWh delivered to distributor (higher value)							0
A(2)	"Wholesale" kWh delivered to distributor (lower value)	354105717	344975881	328430865	334443325	331863453	319895384	331921781.6
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)							0
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	354105717	344975881	328430865	334443325	331863453	319895384	331921781.6
D	"Retail" kWh delivered by distributor	342066123	333246701	316968628	322804697	320281418	307413298	320142948.4
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)							0
F	Net "Retail" kWh delivered by distributor = **D - E**	342066123	333246701	316968628	322804697	320281418	307413298	320142948.4
G	Loss Factor in Distributor's system = **C / F**	1.03520	1.03520	1.03616	1.03605	1.03616	1.04060	1.03679
	Losses Upstream of Distributor's System							
H	Supply Facilities Loss Factor	1.03400	1.03400	1.03400	1.03400	1.03400	1.03400	1.03400
	Total Losses							
I	Total Loss Factor = **G x H**	1.07039	1.07039	1.07139	1.07128	1.07139	1.07598	1.07204

8.0-VECC – 39

Reference: Exhibit 8, Tab 1, Schedule 10

a) Please confirm that, contrary to the text on page 1, the initial volumetric charge of $2.7438/kW was increased by $0.3560/kW to offset the transformer ownership allowance paid to some customers.

Response

a) Collus PowerStream confirms that the volumetric charge has been increased by $0.3560/kW to offset the transformer allowance paid to customers who own their own transformers.

8.0-VECC – 40

Reference: Exhibit 8, Tab 1, Schedule 10

a) Please provide a detailed calculation showing the derivation of the stranded meter weighting factors (i.e. derivation of the $337,914 residential and $131,411 GS<50 allocations).

b) Did COLLUS maintain separate accounting records for meters in the two classes?

Response

a) The stranded meter weighting factors, as shown in Exhibit 9, Tab 1, Schedule 1, Table 11 were reflect the class specific weighted meter costs of smart meters, as filed in EB-2012-0017.
b) Collus PowerStream did not maintain separate accounting records for each customer class.

EXHIBIT 9 - DEFERRAL AND VARIANCE ACCOUNTS

9.0-Staff-32

Ref: E9/T1/S1, p. 28

On page 28, Collus PowerStream requests a "new sub-account for account 1555 to capture the remaining net book value of older smart meters that need to be replaced…"

In Decision and Order EB-2012-0017, issued June 21, 2012 the Board determined that "in granting its approval for the historically incurred costs and the revenue requirement projected for 2012, the Board considers COLLUS to have completed its smart meter deployment. Going forward, COLLUS is not to record any capital and operating costs for new smart meters and any costs for operations of smart meters in Accounts 1555 and 1556. Instead, the costs shall be recorded in regular capital and operating expense accounts (e.g. Account 1860 for meter capital costs) as is the case with other regular distribution assets and costs."

a) Please explain why Collus PowerStream deems a new sub-account necessary given the Board's determination in EB-2012-0017.

Response

a) A new deferral account is required due to the unanticipated technological obsolesce, communication problems, and encryption issues encountered with the first generation installation of Sensus Smart Meters iCon F and iCon G models. These smart meters are deficient and need to be replaced before their normal retirement date. This is a province wide issue that most other utilities are also facing. Please see the response to 2.0-Staff-7.

   Account 4362, Loss from Retirement of Utility and Other Property would normally be used to derecognize assets. Rather than request current rates to cover the loss on derecognition of these smart meters, Collus PowerStream feels it would be prudent to utilize a deferral account and track actual losses and submit the account for approval of disposition in the future. Collus PowerStream plans to mitigate and manage the costs associated with the replacement by extending the replacement over the course of two or three years and through negotiated reduced capital prices from the supplier.

   Since account 1555 previously included a sub-account for the original manual stranded meters, we have suggested this as a possible account for the smart meter stranded costs. Possibly a brand new number would be more appropriate.

9.0-Staff-33

Ref: E9/T1/S1 – Stranded Meters

In *Guideline G-2011-0001: Smart Meter Funding and Cost Recovery – Final Disposition* ("Guideline G-2011-0001"), issued December 15, 2011, the Board states its expectation that proposals for the SMRR would reflect an allocation of the stranded meter costs reflecting the net book value of the conventional meters stranded by replacement by smart meters. In Section 3.7, page 22, of Guideline G-2011-0001, the Board states:

> The distributor should determine and support its proposed allocation, based on the principles of cost causality and practicality. The stranded meter NBV should be recovered through rate riders for applicable customer classes. A distributor must outline the manner in which it intends to allocate the stranded meter costs to the applicable customer rate classes and the rationale for the selected approach. If a distributor has recorded the NBV of the stranded meters by customer class, it should propose class-specific rate riders for each applicable class (Residential, GS < 50 kW and any other classes approved by the Board for smart meter deployment). If the NBV is not known on a class-specific basis, a distributor should propose an allocation between the affected metered customer classes and support its proposal.

Collus PowerStream is proposing separate rate riders to recover the NBV of stranded meters from Residential and GS < 50 kW customers, as shown in Table 11 of this exhibit:

- Residential: $0.98/month for a period of two years; and
- GS < 50 kW: $2.94/month for a period of two years.

This is based on a NBV of $469,325 for stranded conventional meters as of August 31, 2013. This reflects the December 31, 2011 NBV of $504,566 less further depreciation expense of $35,241 recovered in existing rates for the first eight months (January 1 to August 31) of 2013.

In Table 11, Collus PowerStream states that the class allocation is based on its "approved Smart Meter filing".

a) Despite Collus PowerStream filing later, its Application is for rates based on a 2013 forward test year. For the purpose of determining the 2013 revenue requirement, the NBV of stranded meters are removed from rate base, cost allocation and the revenue requirement determination as of January 1, 2013. Please provide further explanation of Collus PowerStream's basis for recording further depreciation until August 31, 2013.

b) Please confirm whether the allocation weights shown in Table 11 reflect the class-specific weighted meter costs of conventional meters or of smart meters.
c) If the weights are based on the class-specific weighted smart meter costs, please provide the rationale for using these weights for allocating the net book value of stranded conventional meters.
d) Please provide a copy of Sheet I7.1 from Collus PowerStream's Cost Allocation study from its previous Cost of Service application.
e) Based on the information provided in d), please provide class-specific SMRRs for the Residential and GS < 50 kW using the customer weighted meter costs and number of customers to allocate the NBV of stranded meters to the Residential and GS < 50 kW customer classes. Please adequately document the methodology for allocating the costs between the classes. Where available, spreadsheets for documenting the data and calculations should be provided in working Microsoft Excel format.

Response

a) Collus PowerStream moved stranded meters out of PPE in July 2012 to a deferral account and continued to amortize the stranded meters until August 31, 2013.

   From a rates perspective, a distributor continues to receive a return (WACC) on the stranded net meter assets and continues to recover the return of the stranded meters in the meter amortization expenses, both of which were included in the revenue requirement and the distributor's current rates. It is only upon a distributor's rates rebasing would this revenue stream cease to continue in rates when the stranded net meter costs are removed from rate base. Accordingly, under this approach until rates rebasing, the regulatory accounting treatment (regardless of whether the stranded meters are recorded in either sub-account 1555 or account 1860 or when they were moved) requires the distributor to continue amortization expense in account 5705.

b) The allocation weights show in Table 11 reflect the class specific weighted meter costs of smart meters, as filed in EB-2012-0017.

c) Collus PowerStream did not maintain separate accounting records for each customer class. Therefore using the class specific weighting of smart meters is the most reasonable method of determining the stranded meter class allocation.

d) Collus PowerStream was not able to locate the Cost Allocation study EB-2006-0247 filed for information with EB-2008-0226.

e) Not available.

9.0-Staff-34

Ref: Account 1508, Sub Account Pension Contributions; E9/T1/S1, pp7- 8 and December 2005 APH FAQ # 13

The December 2005 APH FAQ # 13 states:

> Q.13 Incremental cost assessments and cash pension contributions were authorized for inclusion in 1508, Other Regulatory Assets, sub-accounts as per Board letters of December 20, 2004 and February 15, 2005 respectively. To which date are the recordings authorized in these sub-accounts?
>
> A.13 These recordings are authorized to **April 30, 2006** since effective on May 1, 2006 cost assessments and cash pension contributions amounts are included in the distribution rates of LDCs for the 2006/07 rate year. *[Emphasis added]*

Collus PowerStream is requesting for its December 31, 2011 audited total balance of $60,881 for Account 1508, Sub Account Pension Contributions.

Board staff notes that Collus PowerStream had the opportunity in its 2009 COS rates application to request for the disposition of Account 1508, Sub Account Pension Contributions balance.

a) Please explain why the Board should approve Collus PowerStream's request for disposition of Account 1508, Sub Account Pension Contributions at this time.

Response

a) Collus PowerStream is requesting disposition of the balance in 1508, Sub Account Pension Contributions. This account was used, as per a letter dated February 15, 2005 to all LDC's regarding introduction of new USofA accounts and guidelines on accounting issues. In that letter the Board allowed all LDC's who were members of OMERS to track and record such pension costs and associated carrying charges in account 1508 sub account pension contributions for 2005 and subsequent years. Collus PowerStream recorded pension costs from 2005 up to and including April 2006, at which time as per December 2005 APH FAQ #13, OMERS pension costs were included in distribution rates. For reporting purposes, Collus PowerStream included in quarterly RRR.2.1.1 and annual RRR.2.1.7 outstanding balances for recovery in account 1508. In EB-2008-0226 Collus PowerStream did not request disposition of any group 2 deferral accounts. Collus PowerStream tracked the carrying charges in account 1508, sub account pension costs from inception up to and including disposition of this account with rates effective September 1, 2013. Collus PowerStream is requesting disposition of this account at this time.

9.0-Staff-35

Ref: Account 1508, Sub Account Deferred IFRS Transition Costs; E9/T1/S1, p.7, Table 3; E1/T3/S5, p. 1; DVA Work Form (WF) for 2013 Filers; October 2009 APH FAQ # 1 and E9/T1/S1, p.8-10

In Table 3**,** Collus PowerStream listed Account 1508, Sub Account Deferred IFRS Transition Costs as one of the Group 2 accounts to be disposed for a total of $117,245.

Collus PowerStream indicated that it will adopt IFRS on January 1, 2015.

Board staff notes the Accounting Procedures Handbook – FAQ #1, dated October 2009 stated the following with respect to the disposition of Account 1508 Other Regulatory Assets, Sub-account Deferred IFRS Transition:

> The Board has approved a deferral account for a distributor to record **one-time administrative incremental IFRS transition costs**, which are not already approved and included for recovery in distribution rates.
>
> In the distributor's next cost of service rate application immediately **after the IFRS transition period**, the balance in this sub-account should be included for review and disposition. *[Emphasis added]*

a. Please provide estimates of what additional costs Collus PowerStream is expecting to incur for its IFRS project.

b. Given that Collus PowerStream's IFRS adoption will be on January 1, 2015 and given the APH guidelines, please explain why Collus PowerStream is seeking disposition of the $117,245 balance in this current rate application instead of requesting disposition in the next rate proceeding when the IFRS transition period is complete.

Response

a) During 2012 and year-to-date 2013 an additional $36,205 and $10,000 respectively has been incurred for IFRS transition costs. These costs relate to accounting, legal, and consulting work directly attributable to IFRS conversion needs.

   During 2013 to 2015 we anticipate through our service level agreement with PowerStream to utilize about an additional 100 hours of their expert IFRS staff to review whitepapers and discuss issues if any, train internal staff, assist with modifications to our forms and reports, review our financial statements, assist with opening IFRS balances, review IFRS notes and present to external stakeholders information on the financial statement impacts. The charge will be allocated at cost from PowerStream and result in savings over outside consultants.

We also expect audit and accounting fees during the actual transition year to result in $40-$50k in additional costs.

Some IFRS transition costs are undeterminable at this time due to the uncertainty in the timing and nature of the conversion process.

b) When account 1508 was originally established, the expected IFRS transition date was January 1, 2011. The AcSB has subsequently deferred the mandatory IFRS changeover date for entities with qualifying rate regulated activities four times. The effective transition date is now January 1, 2015. The complexity of applying IFRS to the rate regulated industry has resulted in delays and confusion in the accounting industry that continue to add costs to our utility. At the time of creation of the 1508 deferral account, it was reasonable that it would be a one-time cost and be included in the rate application immediately after the IFRS transition period. However, this is no longer reasonable. A utility cannot be expected to continue to bear the substantial costs of the IFRS transition for this many years before recovery. By the time Collus PowerStream files its next cost of service application it will be 2016 and we will have been tracking IFRS costs for over 6 years that are substantial in nature.

9.0-Staff-36

Ref: Account 1588, RSVA Power and Account 1588, RSVA Power -Sub account Global Adjustment and E9/T1/S1, p.3, Table 2

Table 2 lists Accounts 1588, RSVA Power and Account 1588, RSVA Power, Sub account Global Adjustment for disposition in the amounts of $141,511 and $574,290 respectively.

a. Does Collus PowerStream pro-rate IESO Charge Type 146 Global Adjustment into the RPP portion and non-RPP portion? If not, why not.
b. If so, please provide the supporting spreadsheet for the year 2011 which prorates the IESO Charge Type 146 Global Adjustment into RPP portion and non-RPP portion.

Response

a) Collus PowerStream confirms that monthly IESO charge type 146 Global Adjustment is prorated between RPP and non-RPP portions.

b)

IESO Charge Type 146					
Month	**RPP %**	**Non-RPP %**	**GA Charge**	**RPP**	**Non-RPP**
Jan-11	52.7782%	47.2218%	1,287,253	679,389	607,864
Feb-11	48.2281%	51.7719%	1,071,676	516,849	554,827
Mar-11	48.9631%	51.0369%	1,156,739	566,375	590,364
Apr-11	42.7412%	57.2588%	1,217,082	520,195	696,886
May-11	43.7145%	56.2855%	1,325,373	579,380	745,993
Jun-11	40.7246%	59.2754%	1,036,024	421,917	614,108
Jul-11	49.2342%	50.7658%	834,865	411,039	423,826
Aug-11	46.7002%	53.2998%	904,953	422,615	482,338
Sep-11	35.3131%	64.6869%	934,378	329,958	604,420
Oct-11	41.7439%	58.2561%	1,184,366	494,401	689,966
Nov-11	45.9294%	54.0706%	1,222,932	561,686	661,247
Dec-11	50.7873%	49.2127%	1,454,727	738,817	715,911

9.0-Staff-37

Ref: Account 1592, PILs and Tax Variance for 2006 and Subsequent Years – Sub-account HST/OVAT Input Tax Credits; E1/T1/S2, p.3 and Chapter 2 of the Filing Requirements For Electricity Transmission and Distribution Applications, Sections 2.12.2, June 28, 2012

The 2013 COS filing requirements state:

> The applicant must state whether entries have been made to record variances in the sub-account of Account 1592 to cover the period from July 1, 2010 to December 31, 2012 since the Test Year, which starts January 1, 2013 would include the HST impacts in rates going forward. If this is not the case, please explain. If the rate year begins May 1, entries to record variances in the sub-account of Account 1592 would cover the period from July 1, 2010 to April 30, 2013.
>
> The applicant is required to provide an analysis to support the applicant's conformity with the December 2010 APH FAQs using the example shown in the FAQ #4.

Board staff noted that the variances recorded in 1592 sub account did not cover the period from July 1, 2010 to August 31, 2013 since therate year starts September 1, 2013.

Board staff also noted that Collus PowerStream has not provided the detailed analysis required by S.2.12.2 of the 2013 COS filing requirements.

a) Please file the updated balance for disposition for Account 1592, PILs and Tax Variance for 2006 and Subsequent Years – Sub-account HST/OVAT Input Tax Credits to cover the period of July 1, 2010 to August 31, 2013 using the analysis method in the December 2010 APH FAQ #4.
b) Please provide the details for the analysis for the completion of the record.

Response:

a) Collus PowerStream's filing on April 30, 2013 contained balances for Account 1592, PILs and Tax Variance for 2006 and Subsequent Years – Sub-account HST/OVAT Input Tax Credits ("1592 HST") that were estimated based on a detailed analysis of 2009 purchases and the PST component therein that was charged to OM&A costs. This analysis has been re-examined in order to respond to part (b) of this interrogatory and has resulted in slightly different amounts. Collus PowerStream is updating the values for account 1592 HST and the portion refunded to customers based on the answer to this interrogatory.

As discussed in part (b), the 2009 OM&A costs contained PST totaling $27,639. Using the proxy method in the December 2010 APH FAQ #4 (“FAQ#4”), this results in an amount of $2,303.25 per month to be recorded in 1592 HST.

The period from July 1, 2010, i.e. start of HST, to August 31, 2013, i.e. immediately prior to rebased rates effective September 1, 2013, is 38 months resulting in a total of $87,524 to be booked in 1592 HST plus accrued interest for a total of $89,501. This is summarized in Table Staff 37-1 below.

Table Staff 37-1: Entries for Account 1592 Sub-account HST/OVAT

	Principal		Interest			Interest	
Date	Addition	Total	Addition	Total	Total	Days	Rate
6/30/2010		$ -		$ -	$ -		
7/31/2010	$ 2,303.25	$ 2,303.25	$ -	$ -	$ 2,303.25	31	0.89%
8/31/2010	$ 2,303.25	$ 4,606.50	$ 1.74	$ 1.74	$ 4,608.24	31	0.89%
9/30/2010	$ 2,303.25	$ 6,909.75	$ 3.37	$ 5.11	$ 6,914.86	30	0.89%
10/31/2010	$ 2,303.25	$ 9,213.00	$ 7.04	$ 12.15	$ 9,225.15	31	1.20%
11/30/2010	$ 2,303.25	$ 11,516.25	$ 9.09	$ 21.24	$ 11,537.49	30	1.20%
12/31/2010	$ 2,303.25	$ 13,819.50	$ 11.74	$ 32.98	$ 13,852.48	31	1.20%
1/31/2011	$ 2,303.25	$ 16,122.75	$ 17.25	$ 50.23	$ 16,172.98	31	1.47%
2/28/2011	$ 2,303.25	$ 18,426.00	$ 18.18	$ 68.41	$ 18,494.41	28	1.47%
3/31/2011	$ 2,303.25	$ 20,729.25	$ 23.00	$ 91.42	$ 20,820.67	31	1.47%
4/30/2011	$ 2,303.25	$ 23,032.50	$ 25.05	$ 116.46	$ 23,148.96	30	1.47%
5/31/2011	$ 2,303.25	$ 25,335.75	$ 28.76	$ 145.22	$ 25,480.97	31	1.47%
6/30/2011	$ 2,303.25	$ 27,639.00	$ 30.61	$ 175.83	$ 27,814.83	30	1.47%
7/31/2011	$ 2,303.25	$ 29,942.25	$ 34.51	$ 210.34	$ 30,152.59	31	1.47%
8/31/2011	$ 2,303.25	$ 32,245.50	$ 37.38	$ 247.72	$ 32,493.22	31	1.47%
9/30/2011	$ 2,303.25	$ 34,548.75	$ 38.96	$ 286.68	$ 34,835.43	30	1.47%
10/31/2011	$ 2,303.25	$ 36,852.00	$ 43.13	$ 329.81	$ 37,181.81	31	1.47%
11/30/2011	$ 2,303.25	$ 39,155.25	$ 44.53	$ 374.34	$ 39,529.59	30	1.47%
12/31/2011	$ 2,303.25	$ 41,458.50	$ 48.89	$ 423.22	$ 41,881.72	31	1.47%
1/31/2012	$ 2,303.25	$ 43,761.75	$ 51.76	$ 474.98	$ 44,236.73	31	1.47%
2/29/2012	$ 2,303.25	$ 46,065.00	$ 51.11	$ 526.09	$ 46,591.09	29	1.47%
3/31/2012	$ 2,303.25	$ 48,368.25	$ 57.51	$ 583.61	$ 48,951.86	31	1.47%
4/30/2012	$ 2,303.25	$ 50,671.50	$ 58.44	$ 642.05	$ 51,313.55	30	1.47%
5/31/2012	$ 2,303.25	$ 52,974.75	$ 63.26	$ 705.31	$ 53,680.06	31	1.47%
6/30/2012	$ 2,303.25	$ 55,278.00	$ 64.01	$ 769.31	$ 56,047.31	30	1.47%
7/31/2012	$ 2,303.25	$ 57,581.25	$ 69.01	$ 838.33	$ 58,419.58	31	1.47%
8/31/2012	$ 2,303.25	$ 59,884.50	$ 71.89	$ 910.22	$ 60,794.72	31	1.47%
9/30/2012	$ 2,303.25	$ 62,187.75	$ 72.35	$ 982.57	$ 63,170.32	30	1.47%

10/31/2012	$ 2,303.25	$ 64,491.00	$ 77.64	$ 1,060.21	$ 65,551.21	31	1.47%
11/30/2012	$ 2,303.25	$ 66,794.25	$ 77.92	$ 1,138.13	$ 67,932.38	30	1.47%
12/31/2012	$ 2,303.25	$ 69,097.50	$ 83.39	$ 1,221.52	$ 70,319.02	31	1.47%
1/31/2013	$ 2,303.25	$ 71,400.75	$ 86.27	$ 1,307.79	$ 72,708.54	31	1.47%
2/28/2013	$ 2,303.25	$ 73,704.00	$ 80.52	$ 1,388.31	$ 75,092.31	28	1.47%
3/31/2013	$ 2,303.25	$ 76,007.25	$ 92.02	$ 1,480.33	$ 77,487.58	31	1.47%
4/30/2013	$ 2,303.25	$ 78,310.50	$ 91.83	$ 1,572.16	$ 79,882.66	30	1.47%
5/31/2013	$ 2,303.25	$ 80,613.75	$ 97.77	$ 1,669.93	$ 82,283.68	31	1.47%
6/30/2013	$ 2,303.25	$ 82,917.00	$ 97.40	$ 1,767.33	$ 84,684.33	30	1.47%
7/31/2013	$ 2,303.25	$ 85,220.25	$ 103.52	$ 1,870.85	$ 87,091.10	31	1.47%
8/31/2013	$ 2,303.25	$ 87,523.50	$ 106.40	$ 1,977.25	$ 89,500.75	31	1.47%

As per the Board's Decision March 31, 2010 (EB-2009-0220), 50% or $44,750 is to be refunded to customers.

In this update, Collus PowerStream has not calculated any savings on capital or depreciation as a result of the introduction of HST. This is based on the same reasons as provided in PowerStream's 2013 COS (EB-2012-0161) that are reproduced below (in italics and including Table 3). The same reasons apply to Collus PowerStream's situation as well. This method was accepted by the parties in that proceeding as evidenced in the Settlement Agreement regarding the deferral and variance accounts which included account 1592 Sub-account HST/OVAT.

PowerStream 2013 COS (EB-2012-0161) Settlement Agreement October 24, 2012, page 22:

Issue 5.1 ***Is the proposed clearance of deferral and variance account balances appropriate?***

Complete Settlement: *For the purposes of settlement, the Parties agree that PowerStream's proposed clearance of deferral and variance account balances, including a credit balance in Account 1562 Deferred PILs of $4,084,566, is appropriate.*

PowerStream 2013 COS (EB-2012-0161), Exhibit I, Tab 1, Schedule 12, Page 3 to 6:

FAQ#4 discusses whether there are any savings from HST related to capital and depreciation that are to be recorded in 1592 HST.

In FAQ#4 it is recognized that any savings on capital purchases on or after July 1, 2010 will be reflected in the cost when these assets are included in rate base at the next cost of service application. Any savings in cost due to the elimination of PST will flow to ratepayers at that time and there is no savings to be recorded in 1592 HST.

In FAQ#4 there is further discussion and examples regarding the depreciation on capital additions on or after July 1, 2010, that imply there are savings on depreciation to be *recorded in 1592 HST. There is no explanation as to why there would be an assumption of savings related to depreciation on assets that have yet to be rebased and become part of rates. Furthermore, the Board's Decision talks about incremental ITCs which do not apply to depreciation, only to the capital cost of the asset addition.*

With no clear rationale for the savings on depreciation, PowerStream contacted Board Staff for an explanation. The explanation offered was that since depreciation is an annual expense, it was felt that this should be treated similar to OM&A.

PowerStream questions this rationale. Unlike OM&A which represents current expenditures, depreciation represents the recovery of the original cost of fixed assets over the useful lives. The depreciation in current rates is recovering the original cost of assets acquired at or before PowerStream's last cost of service rebasing (Barrie 2008, PowerStream 2009) on which PowerStream has paid PST. Accordingly there can be no savings from the implementation of HST in 2010.

PowerStream considered if there was any way that there could a realization of savings on depreciation resulting from the implementation of HST during the current Incentive Regulation Mechanism ("IRM") period. This could only occur if there was depreciation in current rates that could be considered to be depreciation on additions after June 30, 2010 and if this depreciation was greater than the actual depreciation on the new additions.

PowerStream considered the mechanics of IRM rate setting, the nature of capital investment and recovery of capital costs through rates. PowerStream's current rates are based on the capital assets in service in 2009 (Barrie 2008) or earlier. As indicated above, the additions after June 30, 2010 (which are subject to HST rather than PST) will not be added to the rate base until PowerStream's next cost of service rebasing for 2013 rates.

The only way that there is depreciation in rates on additions after 2009, is the extent of depreciation on assets included in the last cost of service rebasing that become fully depreciated. This would provide some depreciation expense in rates available to fund depreciation on new additions.

The savings calculated in FAQ#4 would only arise if the annual depreciation expense on additions were 8% lower than the amount of annual depreciation expense on fully amortized assets that is no longer required. The inherent assumption is that additions and related annual depreciation will be 8% lower than the amount of fully amortized assets and related annual depreciation expense. This is extremely unlikely. The historical cost and related depreciation on fully amortized assets is likely to be much lower than the cost of new additions and related depreciation, well in excess of any reduction due to HST, as explained below.

Distribution assets represent the vast majority of PowerStream's rate base and on average have a useful life of 25 years.

The materials cost of utility assets has increased by approximately 88.8% over the 25 year period since 1985 (refer to Table 3 below). An 8% cost reduction from PST, would reduce the material cost index to 155.3 and the estimated cost increase in materials being replaced in fiscal 2010 would be approximately 75.1% greater than the cost of the *original capital that was included in current rates. Similarly the labour cost of constructed assets has increased by 74.7% over the same period.*

The facts indicate that the cost of replacement capital assets and the corresponding depreciation expense generally will be much greater than the cost and associated depreciation of fully depreciated assets being replaced, well in excess of any reduction from the removal of PST.

Table 3: Electric Utility Price Construction Price Indexes

Table 327-0011 Electric utility construction price indexes (EUCPI), annual (index, 1992=100)
Survey or program details:
Electric Utility Construction Price Indexes - 2316
Geography Canada

YEAR	Materials	Annual Inflation	Labour	Annual Inflation
1979	60.3		47	
1980	70.6	17%	51.6	10%
1981	75	6%	57.5	11%
1982	79.9	7%	64.5	12%
1983	79.1	-1%	71	10%
1984	83	5%	73.6	4%
1985	88.7	7%	76	3%
1986	90.7	2%	78	3%
1987	93.3	3%	80.7	3%
1988	101.7	9%	83.6	4%
1989	105	3%	88	5%
1990	106.9	2%	91.3	4%
1991	98.5	-8%	96.9	6%
1992	100	2%	100	3%
1993	102.1	2%	102.7	3%
1994	112.5	10%	104.3	2%
1995	128.1	14%	106.1	2%
1996	126.1	-2%	106.6	0%
1997	125	-1%	110.1	3%
1998	125.4	0%	117.6	7%
1999	126	0%	123.6	5%
2000	128.6	2%	128.8	4%
2001	127.7	-1%	130.7	1%
2002	127.6	0%	132.3	1%
2003	127.8	0%	132.7	0%
2004	132.5	4%	127.2	-4%
2005	138.2	4%	125.3	-1%
2006	155	12%	127.5	2%
2007	165	6%	130.3	2%
2008	167.6	2%	127.7	-2%
2009	167.5	0%	127.2	0%
2010	168.8	1%	132.8	4%

	Materials		Labour	
1985 index	88.7	**B**	76.0	**B**
2010 index (Note 1)	155.3		132.8	
Change in index	66.6	**A**	56.8	**A**
A / **B** =	75.1%		74.7%	

Note 1: 2010 index for materials adjusted by 8% [168.8 x (1 - 8%)] to reflect removal of PST on material purchases; there is no PST on labour costs, so no adjustment is required.

b) Collus PowerStream analyzed its purchases for 2009 and determined the amounts of PST that were included in the OM&A costs. These are summarized in Table Staff 37-2.

Table Staff 37-2: Summary of Purchase Analysis re PST in 2009 OM&A

Purchase Analysis		Cost	PST Portion	% of Cost
Purchased OM&A	$	1,770,957	$17,428.44	0.98%
Burdens applied to OM&A	$	278,805	$ 10,211	3.66%
Total	$	2,049,762	$ 27,639	1.35%

Collus PowerStream's financial system and the way invoices are entered into the account payable system make it clear whether or not PST has been included in the cost. For costs that have PST included in them, the amount of PST has been determined as 8/108 (or 7.40741%) of the amount charged to OM&A.

As per Appendix 2-I, the total 2009 actual OM&A costs are $3,850,193. Appendix 2-K shows that labour costs totaling $1,800,431 was charged to 2009 OM&A. The balance of the costs would come from purchases. This is summarized in Table Staff 37-3.

Table Staff 37-3: Summary of PST in 2009 OM&A

		Cost	**PST Portion**	**% of Cost**
Compensation charged to OM&A per Appendix 2-K	$	1,800,431	$ -	0.00%
"Purchased" OM&A Costs	$	2,049,762	$ 27,639	1.35%
Total OM&A	$	3,850,193	$ 27,639	0.72%

The resulting 0.72% of PST as a per cent of costs reflects the fact that most of Collus PowerStream's costs were not subject to PST such as labour. Most purchases such as services were only subject to GST. Items such as inventory, materials, supplies and repairs are costs that did contain PST.

9-Energy Probe-39

Ref: Exhibit 9, Tab 1, Schedule 1

a) Was Account 1508 - sub-account Pension Contributions created by a generic OEB order or was there a specific account order for Collus PowerStream?

b) What were the carrying charges that would have been recovered if Collus PowerStream had sought recovery of the Pension Contributions sub-account of account 1508 at its last COS rebasing application for 2009 rates?

c) Why does Collus PowerStream believe that it should recover the 2011 costs related to the transition to IFRS now rather than waiting to recover all costs (including those incurred in 2012) when it actually converts to IFRS?

d) Please provide Table 4 expanded to include actual 2012 costs associated with the transition to IFRS. Does Collus PowerStream expect to incur any further transition costs in 2013? If yes, please detail.

Response

a) In an OEB letter dated February 15, 2005 the Board allowed all LDC's who were members of OMERS to record the cash pension costs and associated carrying charges in Account 1508- sub-account Pension Contributions.

b) Had Collus PowerStream sought to dispose of this account in 2009 the carrying charges would have been, $8,156.20.

c) Collus PowerStream believes that it should recover the 2011 costs related to the transition to IFRS now rather than waiting to recover all costs (including those incurred in 2012) when it actually converts to IFRS. The reason for this approach is addressed in OEB 1.0-Staff-35 part b.

d) Table 4 has been expanded to include actual 2012 costs associated with the transition to IFRS and 2013 forecasted transition costs.

Description	2010	2011	2012	2013	Total	Reasons why the costs recorded meet the criteria of one-time IFRS administrative incremental costs
Professional Accounting Fees	33,585.00	56,566.00	18,725.25	10,000.00	118,876.25	Fees associated with preparation of position papers, componentization of assets & draft Financial Statements.
PowerStream Professional Staff				10,000.00	10,000.00	PowerStream expert IFRS staff to review whitepapers and discuss issues if any, train internal staff, assist with modifications to our forms and reports, review our financial statements, assist with opening IFRS balances, review IFRS notes and present to external stakeholders information on the financial statement impacts
External Consultant			13,650.00		13,650.00	Incremental external consultant support dealing with updating the financial records to comply for IFRS & convert CGAAP
Salaries of added staff for IFRS		20,018.00	2,486.00		22,504.00	Incremental staff support dealing with updating the financial records to comply for IFRS & convert CGAAP
Associated Training Costs		2,800.00			2,800.00	Training for IFRS implementation
System Upgrade Requirements		278.00	1,343.75		1,621.75	Project Accounting upgrade for IFRS conversion
Carrying Charges					5,612.37	Estimated to December 31, 2013 - based on OEB approved processes and rates
Total	33,585.00	79,662.00	36,205.00	20,000.00	169,452.00	

Some IFRS transition costs are undeterminable at this time due to the uncertainty in the timing and nature of the conversion process. Collus PowerStream will be converting to IFRS on January 1, 2015. One-time costs will continue to be deferred during 2013 – 2015 related to the transition. Please see OEB 4.0-Staff-35 part a) for additional details.

The utilization of PowerStream's staff to assist with the transition will reduce the amount of professional fees required for one-time transition costs in 2013 – 2015.

9-Energy Probe-40

Ref: Exhibit 9, Tab 1, Schedule 1 &
Exhibit 2, Tab 2, Schedule 1

a) Please show the calculation of the depreciation expense that is implicitly used in the calculation of the accumulated depreciation figures shown in Table 10 of Exhibit 9, Tab 1, Schedule 1 for each of the years shown.

b) Table 3 of Exhibit 2, Tab 2, Schedule 1 indicates that meters were depreciated over a 15 year period. Tables 4-6 of the same exhibit shows that when the meters were transferred to stranded meters, the depreciation period changed from 15 years to 25 years. Please confirm that this was the case.

c) Please reconcile the difference in accumulated depreciation for each of 2009 through 2012 in Table 10 of Exhibit 9, Tab 1, Schedule 1 with the depreciation expense shown in Tables 3-6 in Exhibit 2, Tab 2, Schedule 1.

d) What depreciation rate (or years) has Collus PowerStream used to depreciate the stranded meters in 2013?

e) What is the decrease in the NBV of the stranded meters for each month beyond August 31, 2013?

Response

a) Below shows the calculation of the depreciation expense that is implicitly used in the calculation of the accumulated depreciation figures shown in Table 10 of Exhibit 9, Tab 1, Schedule 1 for each of the years shown.

YR	BAL FWD	1999	2000	PRCH	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2008 Error	YEARLY	ACCUM	UCC
CORR					(24,373)										Corr	DEPREC	DEPREC	
ADD	700,249	65,102	3,548	155,567	101,990	12,741	65,955	21,964	165,131	75,607	34,098	35,832	87,154	29,329	65000/25			1,529,894
2005	17,304	2,568	141	12,477	3,064	510	2,638	879	6,611							46,192	650,775	879,116
2006	17,304	2,568	141	12,477	3,064	510	2,638	879	6,605	3,031						49,217	699,992	829,899
2007	17,304	2,568	141	12,477	3,064	510	2,638	879	6,605	3,024	1,362					50,572	750,564	779,327
2008	17,304	2,568	141	12,477	3,064	510	2,638	879	6,605	3,024	1,364	1,440			2,600	54,614	805,178	724,713
2009	17,304	2,568	141	12,477	3,064	510	2,638	879	6,605	3,024	1,364	1,433	3,490		2,600	58,097	863,275	666,616
2010	17,304	2,568	141	12,477	3,064	510	2,638	879	6,605	3,024	1,364	1,433	3,486	1,177	(10,400)	46,270	909,545	620,346
2011	16,520	2,568	141	12,477	3,064	510	2,638	879	6,605	3,024	1,364	1,433	3,486	1,173	5,200	61,082	970,627	559,264
2012	15,336	2,568	141	12,477	3,064	510	2,638	879	6,605	3,024	1,364	1,433	3,486	1,173		54,698	1,025,325	504,566
2013	13,499	2,568	141	12,477	3,064	510	2,638	879	6,605	3,024	1,364	1,433	3,486	1,173		52,861	1,078,186	451,708
2014	10,314	2,568	141		3,064	510	2,638	879	6,605	3,024	1,364	1,433	3,486	1,173		37,199	1,115,385	414,509
2015	6,155	2,568	141		3,064	510	2,638	879	6,605	3,024	1,364	1,433	3,486	1,173		33,040	1,148,425	381,469
2016	5,060	2,568	141		3,064	510	2,638	879	6,605	3,024	1,364	1,433	3,486	1,173		31,945	1,180,370	349,524

2017	2,855	2,568	141		3,064	510	2,638	879	6,605	3,024	1,364	1,433	3,486	1,173		29,740	1,210,110	319,784
2018	2,169	2,568	141		3,064	510	2,638	879	6,605	3,024	1,364	1,433	3,486	1,173		29,054	1,239,164	290,730
2019	977	2,568	141		3,064	510	2,638	879	6,605	3,024	1,364	1,433	3,486	1,173		27,862	1,267,026	262,868
2020	49	2,568	141		3,064	510	2,638	879	6,605	3,024	1,364	1,433	3,486	1,173		26,934	1,293,960	235,934
2021	160	2,568	141		3,064	510	2,638	879	6,605	3,024	1,364	1,433	3,486	1,173		27,045	1,321,005	208,889
2022		2,568	141		3,064	510	2,638	879	6,605	3,024	1,364	1,433	3,486	1,173		26,885	1,347,890	182,004
2023		2,568	141		3,064	510	2,638	879	6,605	3,024	1,364	1,433	3,486	1,173		26,885	1,374,775	155,119
2024			141		3,064	510	2,638	879	6,605	3,024	1,364	1,433	3,486	1,173		24,317	1,399,092	130,802
2025					3,064	510	2,638	879	6,605	3,024	1,364	1,433	3,486	1,173		24,176	1,423,268	106,626
2026						510	2,638	879	6,605	3,024	1,364	1,433	3,486	1,173		21,112	1,444,380	85,514
2027							2,638	879	6,605	3,024	1,364	1,433	3,486	1,173		20,602	1,464,982	64,912
2028								879	6,605	3,024	1,364	1,433	3,486	1,173		17,964	1,482,946	46,948
2029									6,605	3,024	1,364	1,433	3,486	1,173		17,085	1,500,031	29,863
2030										3,024	1,364	1,433	3,486	1,173		10,480	1,510,511	19,383
2031											1,364	1,433	3,486	1,173		7,456	1,517,967	11,927
2032												1,433	3,486	1,173		6,092	1,524,059	5,835
2033													3,486	1,173		4,659	1,528,718	1,176
2034														1,173		1,173	1,529,891	3
2035																-	1,529,891	3
2036																-	1,529,891	3
2037																-	1,529,891	3
																-		
		65,101	3,548	155,567	77,617	12,741	65,955	21,964	165,131	75,607	34,098	35,832	87,154	29,329	-			

b) Table 3 of Exhibit 2, Tab 2, Schedule 1 indicates that meters were depreciated over a 15 year period. Tables 4-6 of the same exhibit shows that when the meters were transferred to stranded meters, the depreciation period changed from 15 years to 25 years. This however was not the case. Both meters and stranded meters were depreciated over 25 years in 2009. This is a typo on Table 3. (Please refer to 2-Energy Probe -12 for more details.)

It was determined after the stranded meters were moved out, that the remaining NBV of the meters had an average of 15 years remaining. The 15 year rate became the rate of depreciation in the following year tables.

c) The reconciled difference in accumulated depreciation for each of 2009 through 2012 in Table 10 of Exhibit 9, Tab 1, Schedule 1 with the depreciation expense shown in Tables 3-6 in Exhibit 2, Tab 2, Schedule 1 is provided below:

	Table 10 E9/T1/S1	Table 3-6 E2/T2/S1	
2007	$750,564		
2008	$805,178		
2009	$863,275	$863,275	Table 3
2010	$909,545	$909,545	Table 4
2011	$970,627	$970,627	Table 5
2012	$1,025,325	$1,025,325	Table 6

$1,002,534.48 + $22,790.81 = 1,025,325
Total accum amort disposed + continued amort on stranded meters in capital listed below as a reconciling number.

d) A 25 year depreciation rate has been used by Collus PowerStream to depreciate the stranded meters in 2013.

e) There is no decrease in the NBV of the stranded meters for each month beyond August 31, 2013. When new rates become effective September 1, 2013 the amortization of stranded meters stops. The general ledger below provides this detail.

Summary Inquiry

File Edit Tools View Additional Help cshuttleworth COLLUS PowerStream Corp 8/9/2013

Clear

Account 1555 -0003 -00

Description SM Stranded Meter Costs

Year: 2013

Period	Debit	Credit	Net Change	Period Balance
Beginning Balance	$ 531,915.06	$ 27,349.06	$ 504,566.00	$ 504,566.00
January	$ 0.00	$ 4,405.00	($ 4,405.00)	$ 500,161.00
February	$ 0.00	$ 4,405.00	($ 4,405.00)	$ 495,756.00
March	$ 0.00	$ 4,405.00	($ 4,405.00)	$ 491,351.00
April	$ 0.00	$ 4,405.00	($ 4,405.00)	$ 486,946.00
May	$ 0.00	$ 4,405.00	($ 4,405.00)	$ 482,541.00
June	$ 0.00	$ 4,405.00	($ 4,405.00)	$ 478,136.00
July	$ 0.00	$ 4,405.00	($ 4,405.00)	$ 473,731.00
August	$ 0.00	$ 4,405.00	($ 4,405.00)	$ 469,326.00
September	$ 0.00	$ 0.00	$ 0.00	$ 469,326.00
October	$ 0.00	$ 0.00	$ 0.00	$ 469,326.00
November	$ 0.00	$ 0.00	$ 0.00	$ 469,326.00
December	$ 0.00	$ 0.00	$ 0.00	$ 469,326.00
Totals	$ 531,915.06	$ 62,589.06	$ 469,326.00	$ 469,326.00

Currency

by Account

9-Energy Probe-41

Ref: Exhibit 9, Tab 1, Schedule 1 &
Exhibit 2, Tab 2, Schedule 1

a) Please provide more details on the requested new sub-account for account 1555 to capture the remaining net book value of older smart meters that need to be replaced due to new technical requirements.

b) When were these older smart meters replaced? Please provide a table that shows the NBV by year of replacement both historically and, if applicable, in the 2013 test year.

c) If any of these older smart meters were replaced prior to the end of 2012, have these meters been removed from rate base? If so, please reconcile with no disposals shown for smart meters in Table 6 of Exhibit 2, Tab 2, Schedule 1 for 2012 or for meters in previous years.

d) If any of these older smart meters are forecast to be replaced in 2013, have these meters been removed from rate base in the test year? If so, please reconcile with no disposals shown for smart meters in Table 7 of Exhibit 2, Tab 2, Schedule 1 for 2013.

Response

a) See 2.0-Staff-7 and 9.0-Staff-32

b) Collus PowerStream replaced, as needed and prior to identifying the current issues, smart meters as they failed, i.e. there was no replacement schedule. When Collus PowerStream received information pertaining to the failure of a meter, such as a stale meter, the meter was investigated and on a meter by meter basis it was determined if a meter had failed. It was not until the communications issues were identified in the iCon F&G meters that a plan was put in place to remove and replace these meters in order to maintain the reliability of the entire meter population and communications infrastructure.

Collus PowerStream did not remove, from capital, those meters which were replaced.

c) There were a number of meters replaced prior to the end of 2012. Collus PowerStream began replacing meters which were deemed to have failed shortly after installation began in 2009. Some meters were replaced under warranty however the majority were replaced outside the warranty period and were replaced prior to identifying the current security and communications issues. The meters which were replaced prior to the end of 2012 have not been removed from the rate base.

d) The replacement of the First Generation Units is forecasted be at 1500 unit in 2013. At the end of the third quarter's review of the budget if there is some funds left another 100 units could be exchanged brings the total to 1600 units.

Using the average of 22.4 per month it's projected that there will be 269 units that will be replaced in 2013 due to some sort of failure in the meters.

ATTACHMENT 1

4-SEC-10 [EX.4/1/1/P.2]

REVIEW OF COST ALLOCATION

METHODOLOGY REPORT TOGETHER WITH AN

ADDENDUM LETTER DATED AUGUST 20, 2013

HSG Group, Inc.

August 20, 2013

Ms. Cindy Shuttleworth
Chief Financial Officer
Collingwood Public Utilities Service Boards
43 Stewart Road
Collingwood, Ontario L9Y 3Z5
cshuttleworth@collus.com

Addendum to Report to Collus PowerStream Solutions Corp.

Dear Ms. Shuttleworth:

We recently submitted to you our Report, **Review of Cost Allocation Methodology**, dated April 2013.

In the Report, we referred to Collus PowerStream Corp. ("Collus Power"), Collus PowerStream Solutions Corp. ("Solutions"), Collingwood Public Utilities Service Board ("Collingwood Water") and the Town of Collingwood as affiliates of each other.

We understand that within the meaning of Ontario law, Collus Power and Solutions are affiliates, due to their common ownership by Collingwood PowerStream Utility Services Corp. However neither Collus Power or Solutions are affiliates of Collingwood Water or the Town of Collingwood.

In our Report, we evaluated the cost allocation methodology for compliance with the Affiliate Relationships Code ("ARC") as if all inter-company transactions between the entities listed above had to meet the requirements of the ARC.

If you would like to discuss the Report or any aspect of the work, please contact me at your convenience, by phone or e-mail as shown below.

Very truly yours,

Howard Gorman

Howard S. Gorman
President
HSG Group, Inc.

c: Greg Van Dusen

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Phone (516) 244-6806

Collus PowerStream Solutions Corp.

Review of Cost Allocation Methodology

Prepared By

HSG Group, Inc.

April 2013

Table of Contents

Figures

Exhibits

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I. BACKGROUND

HSG Group, Inc. is pleased to submit this Report on our Review of Cost Allocation Methodology ("Review") to **Collus PowerStream Corp. ("Collus Power")**. Collus Power receives certain services from an affiliate, **Collus PowerStream Solutions Corp. ("Solutions")**. Solutions also provides services to other affiliated entities.

HSG Group was engaged by Collus Power to perform this Review and to present our findings. The goals of our Review were:

- To develop a Cost Allocation Methodology)"CAM") to distribute the costs of services provided by Solutions among the businesses to which the services are provided;
- To build a spreadsheet model reflecting the CAM;
- To implement the CAM; and
- To review the CAM for compliance with the *Affiliate Relationships Code for Electricity Distributors and Transmitters* ("ARC") of the Ontario Energy Board ("OEB").

In addition, this engagement included a review of the methodology used by **Collingwood Public Utilities Service Board** ("**Collingwood Water**") to charge **Collus Power** for the use of certain assets owned by Collingwood Water.

HSG Group personnel have significant experience assisting utilities in Canada and the United States in rate and regulatory matters, including cost allocation . Exhibit 5 presents the resume of Howard S. Gorman- President, HSG Group, who performed this Review.

II. ORGANIZATION

Collus Power is an electric distribution utility serving customers in the towns of Collingwood, Thornbury, Stayner and Creemore, located in southeastern Ontario.

Collus Power is a wholly-owned subsidiary of **Collingwood PowerStream Utility Services Corp**., which in turn is 50% owned by the **Town Council** of the Town of Collingwood, and 50% owned by **PowerStream Inc.** PowerStream Inc. is jointly owned by the municipalities of Barrie, Markham and Vaughan, Ontario.

Collingwood PowerStream Utility Services Corp. is also the sole owner of **Solutions** and **Collus PowerStream Energy Corp.**, a non-operating company.

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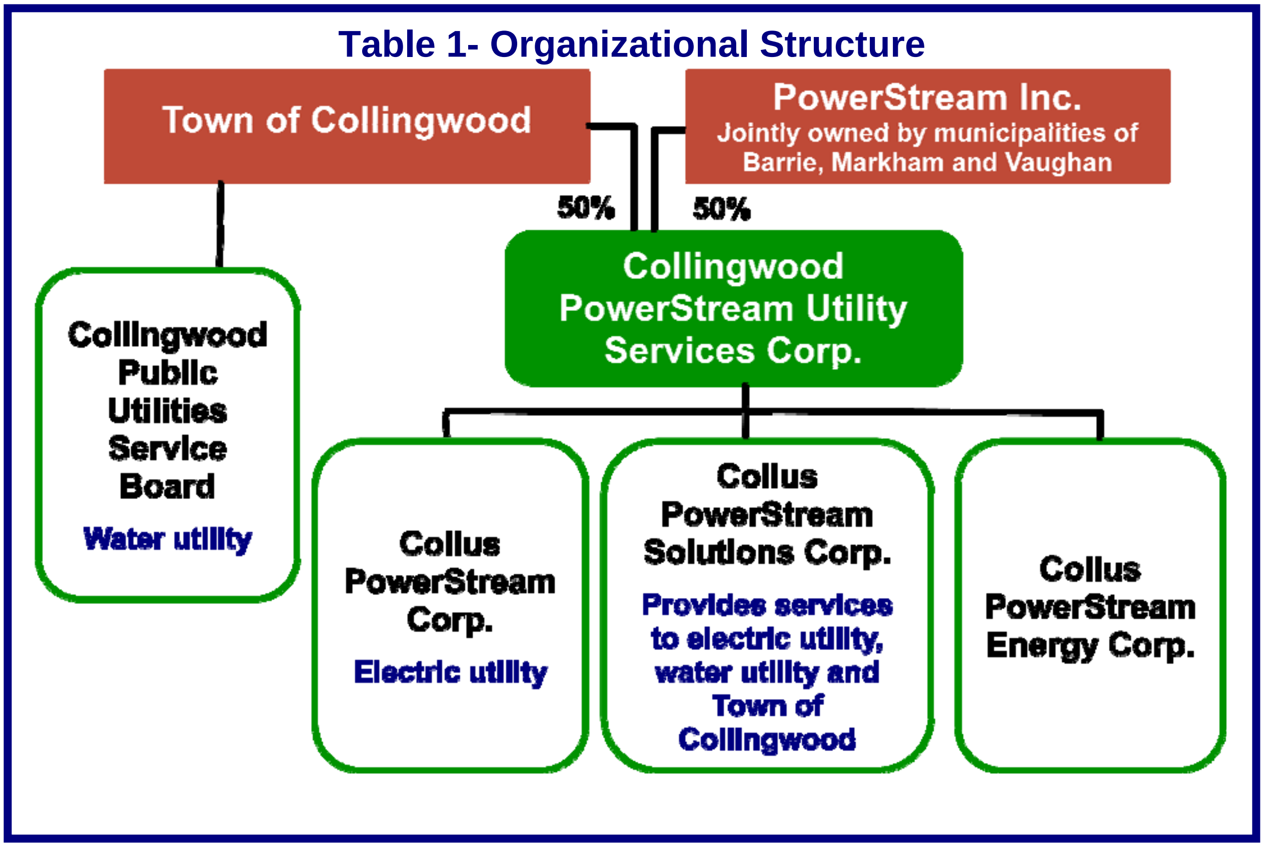
The Town Council of the Town of Collingwood is the sole owner of **Collingwood Public Utilities Service Board** ("Collingwood Water"), a water distribution utility whose service territory overlaps that of Collus Power.

Solutions provides services to Collus Power, Collingwood Water and the Town of Collingwood.

The organizational relationships are presented in Table 1- Organizational Structure.



The following terms are used in this Report:

- Collus PowerStream Solutions Corp. is referred to as Solutions
- Collus PowerStream Corp., the electric utility, is referred to as Collus Power
- Collingwood Public Utilities Service Board, the water utility, is referred to as Collingwood Water
- Town of Collingwood is referred as Town or Municipality

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Collus Power is regulated as to rates by the OEB. Collus Power is also subject to the *Affiliate Relationships Code for Electricity Distributors and Transmitters* ("ARC") of the Ontario Energy Board ("OEB"), with regard to transactions with Solutions.

III. WORK PLAN

The work plan employed by HSG Group to perform the Review comprised the following steps. Each step is discussed in more detail in Section IV.

Step 1. Understand the organizational structure among Solutions and affiliated entities

Step 2. Identify the services provided by Solutions to Collus Power, Collingwood Water and Town

Step 3. Determine the activities that are performed by Solutions employees to provide the services identified in Step 2

Step 4. Determine the portion of each employee's total time devoted to each activity identified in Step 3

Step 5. For each activity identified in Step 3, distribute the employee's time among the businesses for which the activity is performed, based on:

- *Direct assignment- Time studies*
- *Cost drivers*

Step 6. Populate the cost drivers and compute cost driver shares

Step 7. Apply cost driver shares to activities to be allocated

Step 8. Summarize time distribution by business and apply cost-based weights

Step 9. Allocate other costs and revenues

Step 10. Summarize and report

IV. EXECUTION OF WORK PLAN

Step 1. Understand the organizational structure among Solutions and affiliated entities

The organizational structure is presented in Section II and Table 1- Organizational Structure. Solutions provides services to Collus Power, Collingwood Water and the Town of Collingwood.

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Step 2. Identify the services provided by Solutions to Collus Power, Collingwood Water and the Town

Solutions provides services in the administrative and general areas identified in Table 2- Services Provided by Solutions. Solutions does not provide operational support such as linemen, operators and field supervisors.

Table 2- Services Provided by Solutions	
• Customer billing, accounting and collections	• Regulatory filings and compliance
• Call center	• Treasury
• Human resources	• Tax
• Financial accounting and reporting	• Legal
• IT support	

Step 3. Determine the activities that are performed by Solutions employees to provide the services identified in Step 2

Working with Solutions, we identified the role of each Solutions employee in providing the services listed in Table 2- Services Provided by Solutions. Then, the activities performed by each Solutions employee to provide those services were identified. This information is presented in Exhibit 2, column A.

Step 4. Determine the portion of each Solutions employee's total time devoted to each activity identified in Step 3

The portion of each employee's time that is spent on the activities identified in Step 3 was determined based on discussion with the employees as well as management estimates. The distribution of the time each employee spends on each activity is shown in Exhibit 2, column B.

Step 5. For each activity identified in Step 3, distribute Solutions employees' time among the businesses for which the activity is performed, based on:

- Direct assignment- Time studies
- Cost drivers

There are two methods to distribute time (and other costs) among the businesses that use a service– the methods are *Direct Assignment* and *Allocation*.

Direct Assignment is used when the portion of an activity devoted to a business can be reasonably established. Some activities are performed exclusively for one business; the time is

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directly assigned to that business. For many other activities, it was possible to estimate the portion of employee time that is devoted to each business for which the activity (identified in Step 3) is performed. The portion of time spent on each business was determined based on employee input as well as management estimates.

Allocation is used when an activity is performed for more more than one business, but the portions of time required by each business cannot be directly established. In this case, a cost driver must be assigned to distribute the time required for the activity among the businesses. A cost driver is a formula for sharing the cost of a resource (i.e., time) of an activity among those who cause the cost to be incurred. The principles used to assign cost drivers are discussed in Section V.

Direct assignment is preferable to Allocation because it is based on a more direct relationship between activities and time.

The method (i.e., *Direct assignment* or *Allocation*) used to distribute the time spent in each Solutions employee activity, among the businesses for which the activity is performed, is presented in Exhibit 2, column C. For activities where time is Allocated, the cost driver selected for the activity is also shown.

Step 6. Populate the cost drivers and compute cost driver shares

For each of the external cost drivers identified in Step 5, the values were obtained. The share of the total cost driver values represented by each business (Collus Power, Collingwood Water, Town) was computed.

For blended cost drivers, the values were computed based on other cost drivers. For internal cost drivers, the values were computed based on other allocations. The share of the total cost driver by each business (Collus Power, Collingwood Water, Town) was computed.

The allocator values and shares of total values are presented in Exhibit 3.

Step 7. Apply cost driver shares to activities to be allocated

For those activities identified in Step 5 as requiring allocation of time using a cost driver, the portion of the Solutions employee's time devoted to that activity was multiplied by the appropriate cost driver shares, to determine the portion of the employee's time allocated to each business. The portions of each Solutions employee's total time devoted to performing an activity for the different businesses are shown in Exhibit 2; column D for Collus Power; column E for Collingwood Water; and column F for the Town.

For example, for the Executive Assistant and Human Resources Officer devotes 6% of time to the activity Human resources- hiring (Exhibit 2, line 14). This activity is allocated among the businesses using the cost driver 'Employees', which allocates 46.2% to Collus Power and 53.8% to Collingwood Water. Therefore, of the total time spent by this Solutions employee, 2.77% is allocated to Collus Power (6% times 46.2%) and 3.23% is allocated to Collingwood Water (6% times 53.8%).

The total time for this employee is shown on Exhibit 2, line 23, columns D through F.

Step 8. Summarize time distribution by business and apply cost-based weights

As discussed in Step 5, the time devoted to each activity was distributed among the businesses based on either Direct Assignment or Allocation. As discussed in Step 7, the cost driver shares applicable to each business were multiplied by the portion of time devoted to each activity, and the results are presented in Exhibit 2, columns D through F. The time each Solutions employee devotes to the businesses sums to 100%.

Next, the time shares applicable to each Solutions employee were weighted to reflect approximate differences in salaries. The weight for each Solutions employee is shown in Exhibit 2, column C, next to the employee's position. The weighted results are presented in Exhibit 2; column G for Collus Power; column H for Collingwood Water; and column I for the Town.

For example, the Executive Assistant and Human Resources Officer time is allocated 2.77% to performing the activity Human resources- hiring on behalf of Collus Power and 3.32% on behalf of Collingwood Water (Exhibit 2, line 14). These portions are multiplied by the weight for this employee. 1.5, and the weighted allocation of this activity for this employee is 4.15% to Collus Power (2.77% times 1.5) and 4.85% to Collingwood Water (3.23% times 1.5).

The total weighted time for this employee is shown on Exhibit 2, line 23, columns G through I.

Step 9. Allocate other costs and revenues

The result of the allocation of Solutions employees' time is shown on Exhibit 2, line 178. This result is carried forward to Exhibit 1, line 1.

Other costs and revenues of Solutions are allocated on Exhibit 1, lines 2 though 5.

The dollar amounts in Exhibit 1, column A are Solutions budget for 2013. The total allocated dollars are presented on Exhibit 1, line 6, and the shares of the total are on line 8.

Step 10. Summarize and report

The results of the Cost Allocation are presented in Exhibit 1 and summarized in Section VIII, Table 4- Summary of Cost Allocation Results.

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V. COST DRIVERS

As stated in Section IV- Step 5, a cost driver is a formula for sharing the cost of a resource (i.e., time) of an activity among those who cause the cost to be incurred. The guiding principle used to assign cost drivers to activities is cost causation. Cost causation means that there is a causal relationship between the cost driver and the resources used in performing the activity. In some cases, cost causation cannot be easily implemented or established, in which cases selecting cost drivers based on benefits received is a fair treatment.

Other factors considered in assigning cost drivers include:

Practicality – The cost driver should be understandable, obtainable at reasonable cost, and objectively verifiable in the initial year as well as in subsequent years.

Stability – Cost driver values should be reasonably stable from year to year. When estimates are used, the cost driver should be able to be estimated with reasonable accuracy, and estimates should be unbiased.

Materiality – When choosing between cost drivers, small differences can often be ignored in favor of Practicality and Stability.

A. Types Of Cost Drivers

Cost drivers can be classified as external or internal. External drivers are based on data that are external to the cost allocation process, such as physical units or financial amounts.

Internal drivers are based on values computed as part of the allocation process. For example, the cost of a supervisor's salary might be allocated in the same proportion as the salaries of the people being supervised, and the cost of general departmental expenses might be allocated in the same proportion as the specifically assigned departmental activities. Exhibit 2, column K indicates which activities are included in internal cost drivers. For example, the activities that indicate 'CEO' are include n the cost driver 'Internal- CEO'.

B. Cost Driver Values

The cost driver values for the cost drivers used in the cost allocation methodology are presented in Exhibit 3. The exhibit also shows the share of the total cost driver represented by each business (Collus Power, Collingwood Water, Town).

C. Distribution of Solutions Employees' Time

The basis for the distribution of Solutions employees' time among the businesses (i.e., Direct Assignment or Allocation, and within Allocation, the type of allocator) is shown in Table 3- Basis for Distribution of Solutions Employees' Time.

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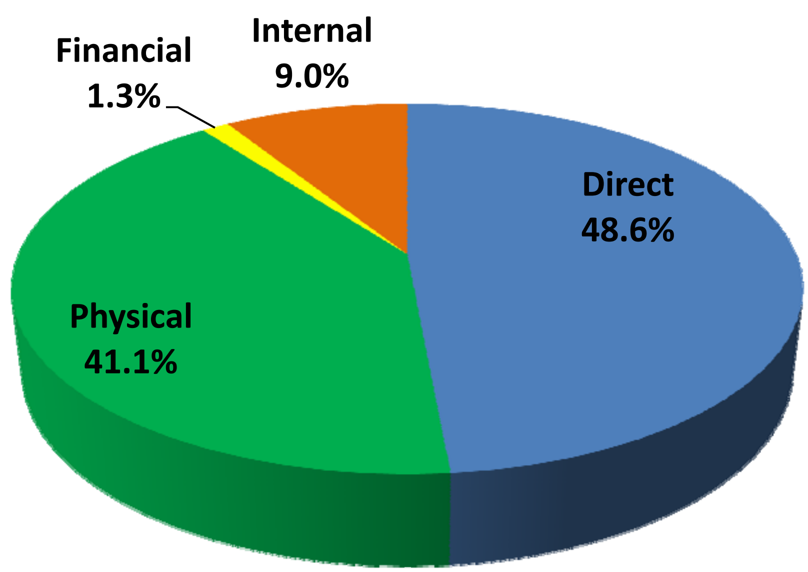
Table 3- Basis for Distribution of Solutions Employees' Time



VI. COMPLIANCE WITH OEB REQUIREMENTS

A. Affiliate Relationships Code

The cost allocation methodology developed for Solutions is consistent with the *Affiliate Relationships Code for Electricity Distributors and Transmitters*, Revised March 15, 2010 ("ARC") of the Ontario Energy Board ("OEB"). The ARC provides:

"Section 2.3.5.1 For shared corporate services, fully-allocated cost-based pricing (as calculated in accordance with sections 2.3.4.1 and 2.3.4.2) may be applied between a utility and an affiliate in lieu of applying the transfer pricing provisions of section 2.3.3.1 or section 2.3.3.6, provided that the utility complies with section 2.3.4.3."

"Section 1.2: 'shared corporate services' means business functions that provide shared strategic management and policy support to the corporate group of which the utility is a member, relating to legal, regulatory, procurement services, building or real estate support services, information management services, information technology services, corporate administration, finance, tax, treasury, pensions, risk management, audit services, corporate planning, human resources, health and safety, communications, investor relations, trustee, or public affairs"

"Section 2.3.4.1: Where it can be established that a reasonably competitive market does not exist for a service, product, resource or use of asset that a utility acquires from an affiliate, the utility shall pay no more than the affiliate's fully-allocated cost to provide that service, product, resource or use of asset. The fully-allocated cost may include a return on the affiliate's invested capital. The return on invested capital shall be no higher than the utility's approved weighted average cost of capital."

Most of the services provided by Solutions to Collus PowerStream and Collingwood Water are 'shared corporate services' as defined by the ARC. In addition, Collus PowerStream and Collingwood Water are affiliated with each other by virtue of the ownership interest of the Town of Collingwood in both utilities.

Customer billing, accounting and collections and Call center are most efficiently provided to Collus PowerStream and Collingwood Water by a single entity (i.e., Solutions), because of the degree of customer overlap. A reasonably competitive market does not exist for these services to be provided to these two utilities.

The services that Collus PowerStream acquires from Solutions are charged at Solutions' fully-allocated cost to provide the services.

Therefore the provision of services to Collus PowerStream by Solutions, and the charges for those services, comply with the ARC.

B. Three-Prong Test

In Docket RP-2002-0133 (*In The Matter Of The Ontario Energy Board Act, 1998)*, the OEB established a "Three-prong test" to determine the appropriateness for inclusion in rates of affiliate costs allocated to a utility:

<u>Cost incurrence</u>: *Were the charges prudently incurred by, or on behalf of, the utility for the provision of services required by Ontario ratepayers?*

The services performed by Solutions on behalf of Collus PowerStream are necessary for the utility in the conduct of its business. The services performed by Solutions are not performed by the utility or another entity.

<u>Cost allocation</u>: *Were the charges allocated appropriately to the recipient companies based on the application of cost drivers/allocation factors supported by principles of cost causality?*

The allocation of costs incurred by Solutions and charged to Collus PowerStream is based on direct assignment and cost drivers, and is therefore supported by the principles of cost causality.

Cost/Benefit: *Did the benefits to the utility's Ontario ratepayers equal or exceed the costs?*

The services provided by Solutions benefit the ratepayers because they are necessary for Collus PowerStream in the conduct of its business. The costs incurred by Solutions in providing the services are reasonable based on comparisons obtained from Statistics Canada.

VII. ASSET USE FEES

Collingwood Water charges Collus Power an Asset Use Fee for the use of certain assets owned by Collingwood Water. These assets are a portion of an office building where Collus Power employees work, and computer assets used by those employees. The Asset Use Fee for each asset type includes the following components:

Depreciation expense for each asset is computed using the same basis as for financial accounting purposes

The return component is computed by applying a weighted average cost of capital of 5.94% to the undepreciated cost (i.e., net book value) of the assets. The rate of return is based on Collus Power's upcoming rate case. The return component is grossed-up to provide for income taxes at statutory Federal and Provincial rates on the return-to-equity portion of the return.

Annual costs include operating costs, property tax and insurance expense, as applicable.

For each asset type, the Asset Use Fee charged by Collingwood Water to Collus Power equals the total cost based on the items above, times the portion allocated to Collus Power. For the building asset, the portion allocated to Collus Power is based on square feet of usable space occupied; and for the computer asset, that portion is based on workstations.

Therefore, the methodology to compute Asset Use Fees is cost-based and the allocation of those costs reflects cost causation. The annual Asset Use Fee to be charged by Collingwood Water to Collus Power is approximately $200,000 for the building, and approximately $22,000 for the computer. The computations are presented in Exhibit 4.

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VIII. Summary of Results and Conclusion

The methodology developed for Collus PowerStream Solutions Corp. to distribute its costs among the businesses it serves is cost-based, consistent with OEB precedent and regulatory practice, and is transparent and efficient.

The cost allocation model developed for Collus PowerStream Solutions Corp. implements this methodology.

The results of the cost allocation methodology are summarized in Table 4- Summary of Cost Allocation Results.

Table 4- Summary of Cost Allocation Results

$000s except per customer	Collus Power	Collingwood Water	Town	Total
Salaries & benefits	$1,293	$710	$174	$2,177
Other costs and revenues, net	32	18	2	52
Total costs, net	$1,325	$ 728	$ 176	$2,229
Overall Shares	**59.4%**	**32.7%**	**7.9%**	**100.0%**
Customers	9,647	6,438		
Monthly cost per Customer	**$11.45**	**$ 9.42**		

In addition, the methodology to compute Asset Use Fees is cost-based and the allocation of those costs reflects cost causation, and is therefore reasonable and appropriate.

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