December 14, 2009

VIA MAIL and E-MAIL

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge St.
Toronto, ON
M4P 1E4

Dear Ms. Walli

Re: Ontario Energy Board File no: EB-2009-0143
Essex Powerlines Corporation
Electricity Distribution Rate Application
Responses to Interrogatories from the Vulnerable Energy Consumers Coalition (VECC)

Please find enclosed the Essex Powerlines Corporations' responses to the interrogatories of the Vulnerable Energy Consumers Coalition (VECC) in the above noted proceeding

Respectively submitted,

Richard Dimmel
General Manager
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ESSEX POWERLINES CORPORATION
RESPONSES TO INTERROGATORIES OF
The VULNERABLE ENERGY CONSUMERS COALITION (VECC)
FILED DECEMBER 14, 2009

<u>GENERAL</u>

<u>Question #1</u>

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

a) Please confirm that all of EPL's delivery points are via Hydro One Networks distribution facilities (i.e., it pays HON Sub-Transmission Rates and Retail Transmission Charges for all power received).

Response:

All Essex's delivery points are via HONI distribution facilities. As per EB-2008-0187, Essex pays HON Sub Transmission (ST) Rates for:

1) Service Charge
2) Meter Charge
3) Common ST Lines Charge
4) Rider #5A for Incremental Capital = $0.021 per kW
5) Specific ST Lines Charge
6) Low Voltage Distribution Station
7) Transmission Connection and Transformer Charge and
8) Transmission Network Charge.

Essex is a Wholesale Market Participant and pays commodity charges via the IESO.

Question #2

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

a) Please confirm that Essex Power Services Corporation (EPS) currently does not provide any services to EPL? If it does, please describe what they are and the basis for the charges.

Response:

We confirm that Essex Power Services Corporation (EPS) does not currently provide any services to EPL.

b) Please confirm that the Application does not include any charges from EPS for services for 2010? If it does, please describe fully what the services are, the amounts charged and the basis for the charges.

Response:

We confirm that the application does not include any charges from EPS for services in 2010.

c) This section does not identify any affiliate transactions between EPL and Essex Power Corporation (EPC).
   - Please confirm that there are such transactions for 2009 and forecast for 2010.

Response:

We confirm that there are transactions between EPC and EPL for shared corporate services as outlined in Exhibit 4, Tab 5, Schedule 1 and Attachment 1, Charts 1 to 5.

   - Please provide a copy of the services agreement between EPL and EPC.

Response:

See response to Board Staff IR# 15a).

Question #3

Reference: Exhibit 1/Tab 4/Schedule 8, page 1

a) Please reconcile the 2010 OM&A value reported here ($6,387,118) with the value reported at Exhibit 4/Tab 1/Schedule 1 ($6,440,941).

Response:

The difference between these two amounts is $53,823, the amount of the capital tax projected in 2010. On Exhibit 4, Tab 1 Schedule 1 the capital tax is included in the total OM&A while in Exhibit 1, Tab 4, Schedule 3, it is split out separately

RATE BASE

Question #4

Reference: i) Exhibit 2/Tab 3/Schedule 3, Attachment 1, pages 13-16
ii) Exhibit 4/Tab 7/Schedule 1, Attachment 1, page 5

a) Please explain why the 2009 Gross Asset balance values reported in Reference (i) and not the same as the 2010 Opening Balances reported in Reference (ii) for certain accounts (e.g., #1835 and #1845) such that the total Gross Asset balance for year end 2009 differs in the two References by roughly $6 M.

Response:

The Fixed Asset Continuity Schedule (Exhibit 2, Tab 3, Schedule 3, Attachment 1) shows the actual additions and accumulated amortization for the individual accounts, while the Depreciation schedule (Exhibit 4, Tab 7, Schedule 1, Attachment 1) shows the balances used to calculate the depreciation expense. The remaining depreciation life was used as representing the remaining useful life of the assets transferred into Essex. In order to make the schedule work, the "grossed up" asset value was used to carry on the proper yearly depreciation values.

An example of this would be the building. The actual net book value was 1,588,454 (this is what is recorded as a capital addition in the continuity schedule) and the building has an annual depreciation of $77,786. The depreciation worksheet shows the value of the building as 1,944,654 which when divided over 25 years equals the annual depreciation of $77,786 shown in the worksheet. (without the 2008 additions)

Question #5

Reference: Exhibit 2/Tab 4/Schedule 1

a) Please provide a summary table of EPL's capital additions for the years 2005-2010, where for each year spending is broken down by the same major categories used in the Exhibit to describe historical spending (e.g., Residential Expansions, Residential Services, … etc.).
(Note: This is similar to Board Staff IR #2 but with a break down of "Capital Additions")

Response:

Year	2005	2006	2007	2008	2009 Bridge	2010 Test
Residential Expansion	$169,795	$108,856	$165,592	$17,359	$60,600	$60,000
Residential Secondary Services	$61,484	$213,634	$168,218	$52,833	$86,025	$86,025
Commercial Expansion	$34,308	$418,912	$427,020	$194,616	$161,440	$312,500
Commercial Secondary Services	$4,405	$34,249	$12,473	$31,161	$10,000	$10,000
Municipal Relocations	$25,015	$145,025	$393,482	$92,817	$134,500	$80,000
Capital Additions	$1,333,658	$2,672,803	$2,224,602	$2,869,046	$2,126,494	$2,401,091
General Capital	$71,781	$29,172	$185,937	$2,817,757	$504,886	$1,207,428
Total	**$1,700,446**	**$3,622,651**	**$3,577,324**	**$6,075,589**	**$3,083,945**	**$4,157,044**

b) Please provide a summary table of EPL's capital additions for the years 2005-2010 by USOA.

Response:

Total By GL	**GL #**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
Land	**1805**	$ -	$ -	$ -	$ -	$ -	$ -
Land Rights	**1806**	$ 737	$ 4,140	$ 31,080	$ 10,229	$ 26,258	$ 25,601
Dist Stn Eq	**1820**	$ -	$ -	$ -	$ 37,676	$ 37,294	$ 1,027
Poles	**1830**	$ 268,877	$ 339,555	$ 445,028	$ 326,533	$ 404,294	$ 534,752
OH Conductor	**1835**	$ 268,597	$ 733,570	$ 537,438	$ 372,372	$ 924,909	$ 513,478
UG Conduit	**1840**	$ 915,653	$ 725,361	$ 429,114	$ 256,022	$ 366,891	$ 451,628

UG Conductor	**1845**	$ 511,000	$ 799,374	$ 899,163	$ 367,004	$ 530,283	$ 585,359
Transformer	**1850**	$ 433,987	$ 828,246	$1,071,097	$ 1,561,967	$ 1,100,203	$1,090,194
Services	**1855**	$ 452,687	$ 396,742	$ 698,396	$ 673,224	$ 620,177	$ 644,645
Meters	**1860**	$ 14,699	$ 194,114	$ 150,959	$ 666,903	$ 77,051	$ 52,784
Land	**1905**				$ 191,700		
Building&Fixtures	**1908**				$ 1,604,560	$ 4,500	$ 40,000
Office Furniture	**1915**		$ 8,808		$ 118,693	$ 15,000	
Compter Hardware	**1920**				$ 44,556		
Computer Software	**1925**		$ 3,664		$ 85,346	$ 10,164	
Transportation Eq	**1930**	$ 71,781	$ 16,700	$ 185,937	$ 489,902	$ 105,273	$ 795,144
Stores Eq	**1935**				$ 24,040	$ 285,000	$ 323,000
Tools, Garage Eq	**1940**				$ 159,335	$ 13,600	$ 27,816
Meaurement Eq	**1945**				$ 20,403	$ 15,000	
Communication Eq	**1955**				$ 79,222	$ 56,349	$ 21,468
Contrib.Refunded	**1995**	$(1,237,572)	$ (427,624)	$ (870,889)	$(1,014,098)	$(1,508,300)	$ (949,850)
Totals		**$ 1,700,446**	**$3,622,651**	**$3,577,324**	**$ 6,075,590**	**$ 3,083,945**	**$4,157,044**

c) Please confirm whether for 2008, 2009 and 2010 all capital spending is assumed to be in-service the year it is spent (i.e., there is no construction in progress at year end). If not, please provide a schedule that sets out the total capital spending by USOA and the outstanding construction in progress as of year for 2008, 2009 and 2010.

Response:

Essex tries to ensure before work is scheduled it can be substantially completed or done in phases. The phases completed at the year end are capitalized as they are in service and substantially complete. This ensures the system is sustainable through the Christmas Holidays (approximately 1-1.5 weeks) when the offices are closed and planned work is not scheduled. Upon return to work in January certain types of work are difficult to do because of ground conditions and weather so every effort is made to complete this work before the end of December.

That does not mean there is no construction in progress, just that the amounts would be below the materiality threshold.

	USOA	2008	2009	2010
Construction In Progress	2055	$ 5,932	Less than $20,000	Less than $20,000

d) On page 5, reference is made to the AIS containing the capital projects for 2009 and 2010 (lines 3-4). Some of the projects listed on pages 26 and 27 are designated as OM&A while others are deemed to be capital. For each of these years, please provide a listing of the projects in the AIS that are capital and reconcile the total with the capital additions reported in Exhibit 2/Tab 3/Schedule 3/Attachment 1.

Response:

As described in VECC question 7a) not all items in the continuity schedule are in the AIS Plan.

The 2009 AIS Plan Capital only totals $ 2,642,000 while the continuity schedule for 2009 in the accounts # 18XX (page 10 only) totals $ 4,207,853. The difference between these two amounts can be explained by the following items in the table which were: from previous scenarios, modifications to older estimates not updated in both tables, new customer/developers/distributed generation added throughout the year and charges that are not included in the AIS plan:

a. Investment ID # 1033, 1165, and 1166 cost decreased by $ 40,000, $91,000, and $39,000 respectively as budget estimates were reviewed and modified
b. Investment ID # 1107, 1108, and 1109 cost decreased by $ 39,750, $26,000, and $5,000 as trends in reactive replacements were trending lower than projected in previous years
c. Investment ID # 1112, and 1114 cost increased by $ 894,000 and $282,400 as Customer/Developer and DG projects were added after the AIS Plan documentation was created
d. Investment ID # 1113 cost decreased by $ 18,625 as trends and economy changed amounts were trended lower
e. Investment ID # 1176 cost of $60,000 inadvertently not included in capital cost schedule
f. Section 2.8 Municipal requests inadvertently omitted from Page 26 table $ 491,000 and these items have a significant amount of contributed capital (account # 1995).
g. Section 3.9 Asset Management and Management Charges are not included in the AIS plan $ 180,244
h. Miscellaneous Capital Charges - finalizing easements, minor upgrades while doing other Capital work, insurance company not paying full amounts for Capital work - increased by $37,584

Investment ID	Name	Cost Category	Total Investment Cost from Page 26	Amounts included in Continuity Schedule Exhibit 2 Tab 3 Schedule 3 Page 10 only	Difference in 2 amounts	Total of Continuity Schedule Exhibit 2 Tab 3 Schedule 3 Page 10 only
1014	4kV conversion Howard Avenue LAS	Capital	$ 225,000	$ 225,000		
1021	LAS LTLT convert to inside WMP	Capital	$ 55,000	$ 55,000		
1022	LEA LTLT convert to inside WMP	Capital	$ 100,000	$ 100,000		
1033	LEA 4kV conversion Erie west (in parking lot and a	Capital	$ 110,000	$ 70,000	**$ (40,000)**	
1106	Pole Replacements - Planned/Reactive	Capital Blanket	$ 81,000	$ 81,000		
1107	Overhead Reactive Replacements	Capital Blanket	$ 75,000	$ 35,250	**$ (39,750)**	
1108	Underground Reactive Replacements	Capital Blanket	$ 80,000	$ 54,000	**$ (26,000)**	
1109	Insulator Replacement Program	Capital Blanket	$ 55,000	$ 50,000	**$ (5,000)**	
1112	Serve New Customer C and I	Capital	$ 220,000	$ 1,114,000	**$ 894,000**	
1113	Serve New Individual Residential	Capital Blanket	$ 162,000	$ 143,375	**$ (18,625)**	
1114	Serve New Subdivisionb Residential	Capital	$ 263,000	$ 545,400	**$ 282,400**	
1115	Live Front Replacements	Capital Blanket	$ 255,000	$ 255,000		
1121	Georgia F2 rear of Elizabeth	Capital	$ 59,000	$ 59,000		
1123	Georgia F2 rear of Lutsch (padmounts)	Capital	$ 70,000	$ 70,000		
1124	Georgia F2 3 phase padmount	Capital	$ 120,000	$ 120,000		
1126	Georgia F2 - Lutsch/Hyatt	Capital	$ 42,000	$ 42,000		
1165	4 LAS Malden F2 Malden to Bouffard - station to SW	Capital	$ 196,000	$ 105,000	**$ (91,000)**	
1166	5/6 Malden F3 on Matchette SW70240 to 7400 Match	Capital	$ 180,000	$ 141,000	**$ (39,000)**	
1167	7 LAS Malden F3 Stuart and Matchette	Capital	$ 63,000	$ 63,000		
1172	TEC Centennial/Woodbridge elbow replacement program	Capital	$ 69,000	$ 69,000		
1173	Add reclosers	Capital	$ 62,000	$ 62,000		
1174	Add/Replace Load Breaks	Capital	$ 40,000	$ 40,000		
1176	Capital/Maintenance - high risk PM	Capital Blanket	$ 60,000	$ -	**$ (60,000)**	
	Section 2.8 Municipal Requests - Inadvertently ommitted from Page 26 table			$ 491,000	**$ 491,000**	
	Section 3.9 Asset Mangement and Management Charges - Not included in AIS Plan			$ 180,244	**$ 180,244**	
	Miscellaneous Capital Charges - finalizing easements, minor upgrades while doing other C			$ 37,584	**$ 37,584**	
	Total		**$ 2,642,000**	**$ 4,207,853**	**$ 1,565,853**	**$ 4,207,853**

The 2010 AIS Plan Capital only totals $ 3,237,000 while the continuity schedule for 2010 in the accounts # 18XX (page 13 only) totals $ 3,878,466. The difference between these two amounts can be explained by the following items in the table which were: from previous scenarios, modifications to older estimates not updated in both tables, new customer/developers/distributed generation added throughout the year and charges that are not included in the AIS plan:

i. Investment ID # 1018 cost decreased by $ 33,000 as one part of this project cannot be done until future conversions are completed
j. Investment ID # 1106 cost increased by $ 81,000 as pole inspections in PM have shown a higher number than originally forecasted
k. Investment ID # 1112 cost increased by $ 10,000 as budget estimates were reviewed and modified
l. Investment ID # 1113 cost increased by $ 375 as amount was rounded down
m. Section 2.8 Municipal requests inadvertently omitted from Page 26 table $ 362,000 and these items have a significant amount of contributed capital (account # 1995).

n. Section 3.9 Asset Management and Management Charges are not included in the AIS plan $ 143,091
o. Same as 1174 but older estimate decrease by $80,000 – both values inadvertently left in the table

Investment ID	Name	Cost Category	Total Investment Cost from Page 27	Amounts included in Continuity Schedule Exhibit 2 Tab 3 Schedule 3 Page 13 only	Difference in 2 amounts	total of Continuity Schedule Exhibit 2 Tab 3 Schedule 3 Page 13 only
1018	Sunnyside F3 4kV rear yard removals	Capital	$ 164,000	**$ 131,000**	**$ (33,000)**	
1019	General Amherst no spare SD	Capital	$ 80,000	$ 80,000		
1031	LEA - 4kV conversion Fox Alley	Capital	$ 79,000	$ 79,000		
1051	AMH 1/0	Capital	$ 125,000	$ 125,000		
1106	Pole Replacements - Planned/Reactive	Capital Blanket	$ 81,000	**$ 162,000**	**$ 81,000**	
1107	Overhead Reactive Replacements	Capital Blanket	$ 33,000	$ 33,000		
1108	Underground Reactive Replacements	Capital Blanket	$ 108,000	$ 108,000		
1109	Insulator Replacement Program	Capital Blanket	$ 75,000	$ 75,000		
1112	Serve New Customer C and I	Capital	$ 670,000	**$ 680,000**	**$ 10,000**	
1113	Serve New Individual Residential	Capital Blanket	$ 143,000	**$ 143,375**	**$ 375**	
1114	Serve New Subdivisionb Residential	Capital	$ 480,000	$ 480,000		
1115	Live Front Replacements	Capital Blanket	$ 160,000	$ 160,000		
1116	AMH sec pedestal upgrade Cherrylawn/Hawthorne	Capital Blanket	$ 48,000	$ 48,000		
1117	AMH 4kV conversion Gore to Dalhousie	Capital	$ 160,000	$ 160,000		
1122	Georgia F1 Oak to Marlborough	Capital	$ 39,000	$ 39,000		
1125	Georgia F2 3 phase west of Lutsch	Capital	$ 59,000	$ 59,000		
1127	Georgia F2 - Lutsch - Mill to Whitwam	Capital	$ 70,000	$ 70,000		
1133	Georgia F2 - Garrison/Danforth	Capital	$ 116,000	$ 116,000		
1154	Sunnyside F2 Divine from FS70719	Capital	$ 41,000	$ 41,000		
1155	Sunnyside F2 Divine from Boismier to Maple	Capital	$ 77,000	$ 77,000		
1156	Sunnyside F2 Divine to Front in alley	Capital	$ 42,000	$ 42,000		
1171	Lesperance U/g replacements upgrades Phase 2	Capital	$ 175,000	$ 175,000		
1173	Add reclosers	Capital	$ 50,000	$ 50,000		
1174	Add/Replace Load Breaks	Capital	$ 102,000	$ 102,000		
1176	Capital/Maintenance - high risk PM	Capital/O&M Blanket	$ 60,000	$ 60,000		
	Section 2.8 Municipal Requests - Inadvertently ommitted from Page 26 table			$ 360,000	**$ 360,000**	
	Section 3.9 Asset Mangement and Management Charges - Not included in AIS Plan			$ 143,091	**$ 143,091**	
1174	Same as 1174 but older estimate -Inadvertently left both in the table			$ 80,000	**$ 80,000**	
	Total		**$ 3,237,000**	**$ 3,878,466**	**$ 641,466**	**$ 3,878,466**

Page 14 and 15 of the Continuity Statement which are accounts # 19XX are not included in the AIS Plan as described in VECC question 7a. Assets included in the AIS Plan are mainly Distribution System Assets.

Question #6

Reference: Exhibit 2/Tab 4/Schedule 1, pages 5-12

a) Please provide an update as to the status of the 2009 developer projects (page 5, lines 16-19). Is there a need to revise the 2009 capital spending/capital contribution forecast? If so, please provide the new values and indicate the impact on the 2010 rate base.

Response:

The 2009 forecasted “Residential Expansion (Subdivision and Multi-Unit Buildings)” category to date in 2009 has shown no construction progress. The 2009 Capital Spending and Capital Contribution forecast will end up being zero. These 2 developers have completed their subdivision electrical distribution designs and have informed Essex they would like to go ahead in 2010 when all their approvals are received. Essex feels that the economy and residential sales will determine if these subdivisions go ahead.

The amounts removed are capital additions of $545,400 and capital contribution of $480,800 for a net capital addition of $64,600. If these 2 projects are deferred to 2010 the Capital Amounts and Contribution would move to 2010 having little impact on the rate base. (they are below the materiality threshold)

b) Please provide a table setting out the total number of new Residential connections and Commercial/Industrial connections underlying the capital additions forecast for 2009 and 2010.

Response:

The Table below shows the estimate numbers for 2009 and 2010 and year to date numbers for 2009. The estimates are multiplied by the average cost per service to get the capital additions in the any year. Additional meters requested by customers/developers are listed in the commercial expansion category because they are adding to buildings and/or units and/or meters to expansions that have occurred in the past.

Year	Residential Expansion (lots serviced)	Residential Expansion $ (dollars)	Capital Contribution $ (dollars)	Residential Secondary Services	Residential Secondary Services $ (dollars)
2009 Estimated	202	$ 545,400	$ 484,400	185	$ 143,375
2009 Year to Date (as of approx. Nov 27)	0	$ 0	$ 0	140	$ 141,045
2010	150	$ 480,000		185	$ 143,375

Year	Commercial Industrial DG Expansion	Commercial Industrial DG Expansion $(dollars)	Commercial Secondary Services	Commercial Secondary Services	C M
2009 Estimated	5	$ 956,090	25	$ 75,000	2
2009 Year to Date	5	$ 242,624	11	$16,383	7
2010	6	$ 605,000	25	$ 65,000	2

c) In the case of the distributed generation expansion (page 9), do the capital contributions cover the entire cost of the project? If not, why not?

Response:

The Capital Contributions cover the entire cost of the project. The amounts forecasted in the 2009 forecast were based on the DSC in affect at the time of rate rebasing preparation and are: $560,000 gross capital additions, $560,000 contributed capital for a net addition of $0.

The recent changes to the Distribution System Code (October 21, 2009), based on Essex's best interpretation will remove almost all of this Capital Contribution except approximately $40,000 which are considered connection assets.

See response also for Energy Probe 11b)

d) What assumptions has EPL made regarding other distributed generation connections in 2009 and 2010 (apart from the one large project discussed); what are the capital costs included for each year and how much of the these costs are covered by capital contributions. If all of the cost is not assumed to be covered by capital contributions please explain why.

Response:

Essex has made the following assumptions in Distributed Generation connections apart from the one large project discussed. Capital costs for renewable distributed generation in 2009 and 2010 were not included in the Application because the Codes, Programs and Guidelines were not completely understood at the time the Application was prepared. Essex will create a plan in

2010 once all details are confirmed. Essex will record/recover all capital in the deferral Account 1531: Renewable Connection Capital Deferral Account or other deferral accounts as described by the Board.

The expected recoverable costs for FIT and MICROFIT based on the DSC, some initial applications and information available would be modeling, impact assessments, metering, low voltage connections and commissioning. These costs are relatively small per application.

Essex has not developed an overall plan based on the OEB's Guidelines: Deemed Conditions of Licence on Distribution System Planning (G-2009-0087) and the recent amendments to the Distribution System Code effective October 21, 2009. An excerpt from page 5 of the Deemed conditions:

"To allow distributors to begin recording expenditures for certain activities relating to the accommodation of renewable energy or the development of a smart grid, the Board is creating four new deferral accounts in the Uniform System of Accounts. These deferral accounts are authorized to be used to record the qualifying incremental investments or expenses, respectively that are described in sections 1 and 2 below. In this context, incremental means that an investment was not included in previous capital plans approved by the Board and/or is not funded through current rates."

The changes to the DSC code describe how Capital Contributions will be treated for generation expansion. Please refer to the DSC on the OEB's web site under Distributed Generation Connection Cost Responsibility. Essex will follow the DSC therefore not all capital costs would be recovered from the generator. The costs not recovered from the generators will be placed in variance and reviewed and approved by the Board for recovery by some other means.

Question #7

Reference: Exhibit 2/Tab 4/Schedule 1, pages 15-41

a) With respect to the table on page 16, please address the following:
- How does the spending shown in the table relate to that shown on pages 26 and 27 of the AIS (e.g., do they both cover the same programs areas and reconcile or do they cover different program areas and if so what are the differences)?
- Does the table cover all of the spending areas subsequently described on pages 16-51 and, if not, what spending areas discussed in this Schedule are summarized in the table?

Response:

Essex has described the reconciliation of the table on page 16 of Exhibit 2 Tab 4 schedule 1 and on page 26 and 27 of the AIS in VECC's question 5d.

The description below applies for 2009 through 2012.

> The table on page 16 of Exhibit 2 Tab 4 Schedule 1 covers most assets related directly to the Electrical Distribution System (the assets that physically deliver electricity to customers) and the Capital Contribution from customers/developers associated with customer requests. The table is inconsistent in the metering USOA 1860 showing smart meters in 2008 but not in 2009 to 2012.
>
> The tables on page 26 and 27 of the AIS are similar except for Software that is directly related modeling and getting feedback from the Electrical Distribution System as summarized below. The AIS plan does not include Economic Evaluation Rebates, Capital Contributions and metering such as smart metering but it does include new meters for new/modified customers.
>
> Sections 3.9, 3.10, and most of 3.11 (except Economic Evaluations) are not re-occurring items but related to organization changes or general accounting practices. These items are not part of the AIS plan.

Sections of spending	Table on Page 16 Exhibit 2 Tab 4 Schedule 1	Table on Page 26 and 27 of the AIS
3.2 Planned and Reactive Replacement 3.3 Planned Conversion of Low Voltage System 3.4 Planned End of Life Replacements 3.5 Planned Overhead and Underground Sustainment 3.6 Planned Operational improvement 3.7 Planned Wholesale Meter Points	included	included
3.8 Planned Asset Management and Management Charges	Included	Not included
3.9 Purchase and Sale to/from Affiliate, Affiliate under Recovery Allocation, Spare Parts Reclassification and Inventory Adjustments	No planned spending in 2009 and 2010	No planned spending in 2009 and 2010

3.10 Planned Interval and GPRS Meter lower threshold to 200 kW	No planned spending in 2009 and 2010	No planned spending in 2009 and 2010
3.11 Economic Evaluation Rebates, Timing of Contributions and Work in Progress, and Obsolete Accounting System	Include only the Economic Rebates. No planned spending in the other areas in 2009 and 2010.	Not Included - Economic Rebates. No planned spending in the other areas in 2009 and 2010.
Section 4	Not included	See table below for included amounts in USOA 1925 and 1955

The items in section 4 are not part of the section 3 table on page 16. The table on page 42 of 51 only applies to the items described in section 4 pages 42 through 51.

Included in the table on page 26 of the AIS and also included in the table in section 4 page 42 of 51 are assets directly related to providing feedback from the electrical distribution system and are Project Investment ID's 1088 FCI Remote Notification, 1090 Display Operations/Storm (Scada), and 1147 AUD on page 26 of the AIS.

Computer Software	Communication Equipment
1925	1955
$52,500	$54,500

Second bullet - The table on page 16 only covers items in Section 3 and the table on page 42 only covers items in section 4.

b) Year to year capital additions shown on page 16 are reasonably consistent. However, in Exhibit 2/Tab 3/Schedule 3, Attachment 1, total capital additions in 2010 are almost $4.2 M relative to 2008 and 2009 values of $2.9 M and $3.8 M. Please identify the major drivers leading to increased overall capital additions for 2010 relative to previous years?

Response:
The major drivers to capital additions in 2010 relative to 2008 and 2009 are described below.

In Computer Software, Account Number 1925, the increase over 2009 is $689,871 and over 2008 is $709,798 respectively. This increase is due to the implementation of the Cayenta Financial (IFRS compliant) and Northstar Billing System as described in Exhibit 2 Tab 4 Schedule 1 page 43 lines 8 and 9 and page 50 starting at line 4 and continuing on page 51.

In Capital Contributions, Account Number 1995, the amounts shown and the change is shown in the table below. The major change from 2009 to 2010 is the capital contribution from the large distributed generator of approximately $560,000 which is included in Exhibit 2 Tab 4 Schedule 1 page 9 starting at line 13 and additional description in response to your question 6c and 6d. The major change from 2008 to 2010 is the larger capital contribution from page 13 section 2.8 Municipal Relocations and Expansions.

Account	2008	2009	2010	Change from 2008	Change from 2009
1995	- $1,014,098	- $1,508,300	- $894,850	$ 119,248	$ 613,450

c) With respect to page 37, are there any charges from EPC in 2010 that will be allocated to capital accounts? If so, please indicate what the associated activities are and, for purposes of the Application, what level of costs was allocated to capital accounts and how.

Response:

Essex does not anticipate any of the charges from EPC in 2010 to be directly allocated to capital accounts.

Question #8

Reference: Exhibit 2/Tab 4/Schedule 1, pages 42-51

a) With respect to page 46, please provide a status update regarding the need for building changes due to MOT's road widening project.

Response:

The status has not changed. We are still in the process of determining the impact to our building from the MOT.

b) Please outline the computer software projects that accounted for the $85,000 in spending in 2008 and the forecast $105,000 spending for 2009 and briefly discuss why the spending was required.

Response:

The bulk of the $85,000 was the book value of software transferred from EPS as part of the corporate restructuring in the amount of $68,000 which includes the Harris billing and financial modules, $5,000 for additional Harris financial modules including payroll, work order, and inventory, $3,500 for Bell Telecost CMS software to meet new Service Quality requirements, and $8,800 for GIS software.

$60,000 of the $105,000 for 2009 was used for our Quadra software. Quadra is our work estimating, asset tracking and time estimating software. The customization was required to more closely match engineering work flows to the software. Time entry customization was required to streamline daily entry into the system. An attempt was also made to integrate asset tracking into GIS to enable better asset tracking and management. The balance of the money was spent on the licensing of scorecard (performance management), preventative maintenance, work management and outage management software.

Essex had a need for outage management software to improve communication during outages between the call centre and operations staff. The tool effectively puts information into the hands of front line staff to help respond to outages more effectively. The scorecard was required to provide a high level overview of key performance indicators and help management with decisions based on real-time statistics. Essex had the need to more efficiently run it's preventative maintenance program. The acquired software has allowed staff to spend less time to manage the program. The system is integrated to GIS, automates budgeting and reporting, allows for electronic field inspections and eliminated the need for paper reports.

c) With respect to pages 50-51, please describe more fully why how/why the current ERP system does not allow for IFRS compliance.

Response:

The current financial system does not have a fixed asset module that is required for IFRS compatibility. The system does not have an effective flexible report writing tool for multiple sets of books to meet regulatory (quasi-IFRS) and IFRS financial statement production capabilities.

It should be noted that the current system is not just required to meet the needs of IFRS. While this is a major financial change that is coming, there are other aspects of the current financial system that will not be able to meet our needs for the next rebasing period. The current system is not flexible and is no longer being supported for enhancements or improvements. The current system may not meet the future needs required by the new HST legislation either.

d) What is involved with the Harris upgrade as opposed to the financial system upgrade and why are both required?

Response:

NorthStar version 6.3 is the most recent release of the CIS delivering a highly functional and user-friendly utility billing solution, adding to the core functionality and usability of the software as well as introducing overall process improvements. NorthStar 6.3 will include a new Graphical User Interface to improve operational customization per user to facilitate workflow. The change to Java 2 Enterprise Edition provides a fully functional client that remains super thin to ensure optimum performance and minimum client hardware requirements.

For the Customer Service Representative, the new software allows access to multiple customers simultaneously without having to launch a second or third session of the software. Once located in the system, navigating to all other customer information has been optimized. A customizable summary of critical and common account information provides for quick customer responses. Each Customer screen is opened in a separate window that can be maximized, minimized or custom sized allowing multiple detail screens to be open for each customer.

The advancements incorporated in NorthStar 6.3 will improve customer call centre response time minimizing time on the phone with the customer and ultimately resulting in higher SQI results. The old version of the software will no longer be supported.

Both are required to migrate to new versions of the software as the old versions are no longer supported and will be obsolete.

e) What is the status of this project and what is the basis for the estimated $795,144 cost?

Response:

At present, we are completing the process of our research of the solutions from MS Dynamics (Great Plains), SAP, Cayenta and Harris (Northstar). We are investigating all options to ensure that we are getting the best value for these future expenditures. It has become apparent recently that we will not change to the new financial system at the beginning of or in early 2010 as originally expected due to the inability for the software vendors to meet the current need for these systems. The target is now mid year 2010 for the financial system.

The Harris Northstar billing system will still proceed in the first quarter of 2010.

We expect that approximately $314,000 of the estimated $795,000 will be customization, training and overtime costs incurred during the implementation. This also includes costs for downtime and lost productivity during system conversion.

We expect that approximately $419,105 of the cost will come from the ERP solution software cost, licensing fees, data migration from existing ERP to new solution, project management, hosting cost, and 3rd party integration and consulting. We have other hosted ASP applications that will be effected with the change in ERP system and development and integration costs will be a part of that cost.

f) What other alternatives are being considered and is the approach EPL is currently reviewing preferable?

Response:

There are no alternatives as the current financial and billing systems are obsolete and must be replaced.

Question #9

Reference: Exhibit 2/Tab 4/Schedule 5 (AIS)

a) With respect to the 2010 projects listed on page 27, please identify the two capital projects with the lowest Strategic Objective Score and, in each case, discuss the implications of either not proceeding with the project or deferring ti for one year.

Response:

The two lowest Strategic Objective Score are from projects are:

1) **1031** Leamington 4kV conversion of the Fox Alley – Score **1.04** and
2) **1117** Amherstburg 4kV conversion Gore to Dalhousie – Score **1.21.**

For project 1031, the implication of not proceeding would be the following:

1) A Field Risk Assessment done in 2008 (by Lines and Operation Manager Staff) had identified the asset is need of work within 2-3 years. The poles and hardware are approximately 50 years old. The clearances are less than current standards and the secondary is open wire increasing the risk to the public, workers, and any joint use workers. Since the clearances are poor and the secondary is open, the line section is difficult to operate as well.
2) This project must be completed before projects upstream such as 1122 and 1136 that also have Risks and Strategic Objectives. The optimizer optimizes all these factors to give the best mix of dependent projects as well. The Georgia Station was built in 1959 and tests have shown deterioration in insulation and windings providing objective and risk to the station removal which all projects downstream are dependent on.
3) Project 1122 cannot be completed until this project 1031 is complete. Project 1122 has rear yard enclosed high voltage overhead wire which requires higher levels of vegetation management and has significant risk to the public and our workers to work on these poles. The task of climbing poles in a rear yard is the highest risk to Essex workers as assessed by Essex RRAM (Regulation and Risk Assessment Management). Essex designs to remove enclosed difficult to access rear yard high voltage overhead wires.

Additionally, for project 1031, the implication of deferring one year would be the following:

1) Delayed the 4kV Conversion Plan as described in Exhibit 2 Tab 4 Schedule 1 Section 3.3 starting on page 26.
2) Based on the resource plan there may not be enough resources (linepersons) to complete the work in that year and still meet the schedule around other dependent projects. The work in Section 3.3 is labour intensive and only a certain amount can be scheduled in each year.
3) There is a higher risk that a failure may require maintenance because of the age of the assets and these costs will be avoided.

For project 1117, the implication of not proceeding would be the following:

1) A Field Risk Assessment done in 2008 (by Lines and Operation Manager Staff) had identified the asset is need of work within 2-3 years. The poles are in need of replacement. The primary and secondary wire is in a difficult to access enclosed backyard. Operating this line would mean increasing the risk to the public, workers, and any joint use workers. This line section is difficult to operate as well.
2) This project has rear yard enclosed high voltage overhead wire which requires higher levels of vegetation management and has significant risk to the public and our workers to work on these poles. The task of climbing poles in a rear yard is the highest risk to Essex workers as assessed by Essex RRAM (Regulation and Risk Assessment Management). Essex designs to remove enclosed difficult to access rear yard high voltage overhead wires to remove this risk.

Additionally, for project 1117, the implication of deferring one year would be the following:

1) The rabbit or transformer installed in this section has no backup and the risk of failure is simlar to the 4kV Conversion Plan as described in Exhibit 2 Tab 4 Schedule 1 Section 3.3 starting on page 26.
2) Based on the resource plan there may not be enough resources (linepersons) to complete the work in that year and still meet the schedule around other dependent projects. The work in Section 3.3 is labour intensive and only a certain amount can be scheduled in each year.
3) There is a higher risk that a failure may require maintenance because of the age of the assets and these costs will be avoided.

b) For 10 highest cost capital projects in the Preventative or Enhancement categories (page 27), please provide a more detailed description of the project and basis for the projected level of spending.

Response:

The 10 highest cost capital projects are listed in the table at the end of this response. Referring to the categories and descriptions in Exhibit 2 Tab 4 Schedule 1 these 10 projects fall into the section 3 categories. Project 1117 and 1031 are also described in VECC question 9a. The basis for the project costs in these 10 projects is based on the following table.

Project Investment ID #	**Basis**	**Reference to the category of program as described in Exhibit 2 Tab 4 Schedule 1 page 15 to 35**
1171 Lesperance Replacements Phase 2	Conceptual design and budget estimate	Section 3.2 Planned and Reactive Replacement, 3.4 Planned End of Life Replacement, and 3.6 Planned Operational Improvement
1031 Fox Alley conversion 1019 General Amherst conversion 1133 Georgia F2 – Garrison/Danforth conversion 1117 Gore to Dalhousie conversion 1018 Sunnyside F3 conversion	Conceptual design and budget estimate	Section 3.3 Planned Conversion of Low Voltage System
1115 Live Front Replacement, 1174 Load Break Switch, 1106 Pole Replacement	Average historical unit cost replacement times the number of assets requiring replacement	Section 3.4 and 3.6 Planned End of Life Replacements and Operational Improvements
1051 Amhersburg 1/0 replacement	Conceptual design and budget estimate	Section 3.5 Planned Overhead and Underground Sustainment

Investment ID #1171 Lesperance Underground replacements and upgrades phase 2 This project includes the replacement of 0.95 km underground high voltage cable, 2 transformers and 1 switching unit with new conduit, cable, switching units and transformers. This equipment was installed in the 1970's and requires replacement because the cable is failing, the switching unit is severely rusted and the pole mounted switches have flashed over a number of times because of poor design and low clearances making it unsafe to operate.

Investment ID's # 1031 Fox Alley conversion, 1019 General Amherst conversion, 1133 Georgia F2 – Garrison/Danforth conversion, 1117 Gore to Dalhousie, and 1018 Sunnyside F3 are conversions from lower voltages to higher voltages.

These projects are a continuation of Essex conversion plan to remove substations and step-down transformers that tests have shown are deteriorated and working on these assets increases the risk to Essex workers. Risk assessments have identified the major issues of concern.

Investment ID # 1031 Fox Alley Conversion

Rebuild and convert approximately 140m of overhead poles, lines, three transformers banks, and secondary services from 4 kV to 27.6 kV primary voltages.

Investment ID #1019 General Amherst Conversion

Rebuild and convert approximately 250 m of underground, lines, two transformers banks, and secondary services from 4 kV to 27.6 kV primary voltages. This asset is currently an underground in a backyard and front yard and will remain in a similar location underground accessible through driveways, parking lots and open park. Land and land rights for this project are required as well.

Investment ID #1133 Georgia F2 – Garrison/Danforth conversion,

Rebuild and convert approximately 420 m of overhead poles, lines, two transformers banks, and secondary services from 4 kV to 16 kV primary voltages. This asset is currently overhead in a backyard and will be moved to the front yard and placed underground.

Investment ID #1117 Gore to Dalhousie

Rebuild and convert approximately 1,100 m of overhead poles, lines, eleven transformers banks, and secondary services from 4 kV to 27.6 kV primary voltages. This asset is currently a combination of underground and overhead in a backyard and front yards and will be moved to the front yard and placed underground with some accessible alleys still maintained as overhead. Land and land rights for this project are required as well.

Investment ID #1018 Sunnyside F3

Rebuild and convert approximately 2,080 m of overhead poles, lines, nine transformers banks, and secondary services from 4 kV to 27.6 kV primary voltages. This asset is currently an overhead line in both backyard and front yards and will be moved to the front yard and placed underground with some accessible alleys still maintained as overhead. Land rights for this project are required as well.

Investment ID #1115 Live Front Replacements

Live Front Pad mount transformers were designed and installed with live high voltage parts open to the environment inside the transformer. These transformers fail or cause outages at significantly higher rates than the newer modern dead front design. The transformers are also located in rear yards and are sometimes difficult to find and access because buildings and other landscaping shelter and hide them. The open interior design allows vegetation to grow, dust and dirt to build up, and water to flood the inside. These items increase the amount of power outages and require significantly more inspection, cleaning, spraying and maintenance. This is a replacement program geared at replacing approximately 12 of the worst performing and highest O and M cost transformers per year. The list of remaining live front transformers has been prioritized for replacement by condition assessment and inspections. There are approximately 92 transformers remaining. As many of these transformers are underutilized because they were installed when electric heat was prevalent, they typically can be replaced at a 2 to 1 ratio reducing the number of assets.

Investment ID #1174 Load Break Switches

Load Break Switches were designed and installed with live high voltage parts open to the environment. Older Load Break Switches fail or cause outages to be longer at significantly higher rates than the newer modern design. This is a replacement program is geared at replacing approximately 4 of the worst performing and highest O and M cost Load Break Switches per year. Replacement is prioritized for replacement by condition assessment and inspections (PM). Operationally as the system expands and is modified, Load Break Switches need to be added to ensure the same level of reliability is maintained. This program also adds switches where needed based on operational assessments.

Investment ID #1106 Pole Replacement Program

Essex pole replacement program is designed to replace the poles with less than 60% of the remaining strength. 60% strength is the Canadian Standards Association (CSA) minimum requirement for pole strength. Poles with less than 60% strength are identified by the Preventative Maintenance (Investment Id # 1149) and inspection program. These poles are prioritized for replacement by condition assessment and inspections. Please also reference Exhibit 2 Tab 4 Schedule 1 Page 17 starting at line 3 through page 19.

Investment ID #1051 Amherstburg 1/0 Sandwich Street Replacement

This one time project is designed to replace approximately 0.7 km of undersized overhead conductor, overhead high voltage lines over buildings, and either get easements or move this line to the road or an area with easements.

This line was previously owned by Ontario Hydro and the size of conductor limits the amount of load that Essex can place on this line. During times of high load in the summer, Essex typically has to operationally adjust the system to maintain adequate voltage to our customers.

The high voltage line also runs over a building which does not comply with CSA 22.3 and Essex's current standards. This line over buildings increases the risk to the public should the line fail and fall.

This line location also has no Land Rights associated with it. Essex has been able to obtain some land rights from developers as expansions were done in the past but this remaining section has no land rights.

Investment ID	Name	Project Type	Cost Category	Description	Total Investment Cost	Units	Units - 2010 Select...	Dependency ID	Strategic Object... Score	Highest Risk Deferral	Consequence Highest Risk	Probability of High Risk
1171	Lesperance U/g replacements upgrades Phase 2	Preventative	Capital	Lesperance U/g replacements upgrades Phase 2	$ 175,000	1	1	0	1.235	6	3	2
1018	Sunnyside F3 4kV rear yard removals	Enhancements	Capital	Sunnyside F3 - removal of backyard primary leaving secondary poles	$ 164,000	6	5	0	1.69	3	3	1
1117	AMH 4kV conversion Gore to Dalhousie	Preventative	Capital	AMH Gore to Dalhousie - eliminate rabbits	$ 160,000	2	2	0	1.21	5	5	1
1115	Live Front Replacements	Preventative	Capital Blanket	Live Front Replacements	$ 160,000	92	12	0	1.485	9	3	3
1051	AMH 1/0	Enhancements	Capital	replace OH conductor over building and undersized	$ 125,000	3	3	0	1.43	9	3	3
1133	Georgia F2 - Garrison/Danforth	Enhancements	Capital	Georgia F2 - Garrison/Danforth	$ 116,000	3	3	1134	1.495	6	3	2
1174	Add/Replace Load Breaks	Preventative	Capital	Add/Replace Load Breaks	$ 102,000	4	1	0	1.35	12	3	4
1106	Pole Replacements - Planned/Reactive	Preventative	Capital Blanket	Planned and Reactive pole replacements based on scheduled and u	$ 81,000	15	15	0	2.09	8	4	2
1019	General Amherst no spare SD	Enhancements	Capital	no spare SD for General Amherst	$ 80,000	1	1	0	1.23	5	5	1
1031	LEA - 4kV conversion Fox Alley	Enhancements	Capital	convert 3ph and 1 ph banks work part done	$ 79,000	1	1	1122	1.04	6	3	2

c) How was the 2010 level of spending established for the various capital projects in the Reactive category?

Response:

The level of spending established for the various capital projects in the two Capital Reactive Categories (Projects 1107 and 1108) are based on previous years trends multiplied by an average cost per occurrence.

Project 1107 Overhead Reactive Replacements are typically transformers that are replaced because they fail due to age, weather, lighting, etc. These items could also reflect any of the categories described in Exhibit 2 Tab 4 Schedule 4 Section 3. For example the Table below depicts some Budget vs. Actual amounts.

	2008	2009	2010
Estimated # of occurrences	5	5	5
Estimated Cost per occurrence	$6,600	$7,050	$6,600
Budget	$33,000	$ 35,250	$ 33,000
Actual # of occurrences	9	6	--
Actual Cost per occurrence	$ 6,838	$6,242	--
Actual	$61,549	$37,453	--

Project 1108 Underground Reactive Replacements are typically transformers that are replaced because they fail due to age, weather, lighting, etc. These items could also reflect any of the categories described in Exhibit 2 Tab 4 Schedule 4 Section 3. For example the Table below depicts some Budget vs. Actual amounts. Underground Assets are typically more expensive and therefore the budget and cost is higher.

	2008	2009	2010
Estimated # of occurrences	10	5	5
Estimated Cost per occurrence	$10,800	$10,800	$10,800
Budget	$108,000	$ 54,000	$ 33,000
Actual # of occurrences	5	6	--
Actual Cost per occurrence	$ 14,952	$13,893	--
Actual	$ 74,762	$ 83,355	--

Question #10

Reference: i) Exhibit 2/Tab 5/Schedule 1, Attachment 1
II) Exhibit 3/Tab 1/Schedule 3, Attachment 1

a) Please confirm that the price used to determine commodity costs was the RPP price from the Board's April 2009 RPP Report.

Response:

Essex confirms the use of the determined commodity costs from the April 2009 RPP Price Report from the Board

b) Based on the most recent 12 month data, what proportion of EPL's sales (i.e., kWh) are to RPP customers?

Response:

Based on the most recent 12 month of data Essex estimates its RPP customers to make up approximately 54% of total kwhr sales.

c) Are any of EPL's retail customers registered as Market Participants and billed directly for commodity costs by the IESO?

Response:

No, Essex does not have any retail customers registered as Market Participants and billed directly for commodity costs by the IESO.

d) If the response to part (c) is yes, what is their forecast use for 2009 and 2010 and has it been excluded from the calculation of the commodity cost used to determine the working capital allowance?

Response:

N/A

e) If the $0.0607 value used for the commodity cost is based on the RPP price, please undertake the following:
- Using the same source, estimate the commodity cost for non-RPP customers
  Response:
  The commodity cost for non-RPP customers would be approximately $0.05914

- Estimate an average commodity cost for all sales based on the weighted average of the RPP and non-RPP forecast costs.

  Response:

  The average commodity cost for all sales based on the weighted average of the RPP and non-RPP forecast costs would be $0.05999.

- Re-estimate the Total Commodity cost for 2010.
  Response:
  If Essex changes the commodity cost to the weighted average price listed above it would reduce our working capital allowance by $67,877. However, since the April 2009 report cover the period of May 1, 2009 to April 30, 2010, Essex feels if an update were to be done it should be done using the commodity costs as reported in the latest Board Report for the period of November 1, 2009 – October 31, 2010 as this report covers a period closer to that of the rate filing. This report yields a weighted average cost of power of $.06033 which would decrease the working capital allowance by $36,263 bringing it to $8,138,352. Also see response to Energy Probe Interrogatory Questions #12 (d-f).

LOAD FORECAST & OPERATING REVENUE

Question #11

Reference: Exhibit 3/Tab 1/Schedule 2, Attachment 1 (ERA Report)

a) With respect to pages 2-3, please explain why the "three other points" do not receive volumetric charges for distribution.

Response:

See response to Board Staff IR# 5d).

The assets that get the energy to these ED points are all owned and operated by Hydro One. Essex and Hydro One agreed it was therefore fair to only charge the fixed cost for settlement because Essex did not operate or maintain the assets but had to settle the energy as a retail embedded distributor.

b) With respect to page 14, please indicate the kW volumes for 2010 associated with the Embedded Distribution points that are currently not subject to volumetric charges – reporting the GS>50 and Intermediate volumes separately.

Response:

Essex's load forecast was done for kW that attracted volumetric charges. The 3 Embedded Distribution points which are currently not subject to volumetric charges were not included in the load forecast.

c) Based on the most recent 12 months of available data please indicate the total kW delivered (i.e. monthly values summed for 12 months) to HON through each of these three delivery points.

Response:
Based on November 1, 2008 – October 31, 2009 the following kWs have been delivered:

Howard (Intermediate) - 67,939
Western-Texas (GS>50) - 6,314
Canard-Detroit (GS>50) - 17,608

d) With respect to pages 3-4, did ERA consider using an approach similar to that employed by the Consultant for Cooperative Hydro Embrun's 2010 Rate Application (EB-2009-0132)? If not, why not? If yes, why was the approach rejected?

Response:

Cooperative Hydro Embrun used a load forecast approach based on monthly wholesale deliveries for their 2010 Rate Application (EB-2009-0132). As indicated on page 3 of the Essex Load Forecast Report prepared by ERA, this approach was also investigated for Essex Powerlines' load forecast. However, as the report goes on to state:

> *While this approach assumes that the classes generally have a similar degree of weather and economic sensitivity, and this may be true in varying degrees in some LDCs, it is apparent that this is not the case for Essex Powerlines. The table below (Table 1) illustrates the significantly different load profiles for the different classes and total purchased kWh… Due to the differences in the class and purchase profiles and the*

additional issues with respect to embedded generation and distribution, it was decided to adopt a normalized average use per customer ("NAC") approach to forecast weather normal class throughput for Essex Powerlines. While this may not be a preferred approach, the Board has seen and approved of this approach for LDC rebasing applications in the past. (Exhibit 3/Tab 1/Schedule 2, Attachment 1 (ERA Report), pp.3-4).

Of particular concern are the quantum and directional differences in trend of purchased wholesale kWh and class kWh in residential, GS<50 kW and GS>50 kW reported in Table 1 of the Load Forecast Report. As stated above, this may be due to differences in economic and weather sensitivity, but is undoubted exacerbated by the presence of embedded generation and embedded distribution. For these reasons, the wholesale purchases approach was rejected in favour of the "NAC" approach.

e) While EPL's service area is adjacent to EnWin's and may have similar "weather", the use of electricity for space conditioning (i.e. penetration rates) may differ between the two utilities. Did ERA review the appliance saturation surveys undertaken by the two utilities as part of HON's weather normalization analysis in order to determine if usage characteristics were similar between the two utilities? If yes, please provide the results. If no, what is the basis for ERA's assumption that the weather normalization factors should be similar?

Response:

ERA did not review any appliance saturation surveys. As explained in the Load Forecast Report, the main reasons for using the EnWin normalization factors were geographic proximity and similar weather, more recent analysis than 2004 (which is the year for HON's weather normalization analysis) and more than a single year, which has been suggested as a shortcoming of relying on HON's weather normalization analysis by some in the past.

f) With respect to page 11, please contrast the assumed growth in residential customer for 2009 and 2010 with the number of new Residential connections assumed for 2009 and 2010 in Exhibit 2.

Response:

See response to Energy Probe IR#13.

g) Similarly, please contrast the assumed growth in GS and Intermediate class customers for 2009 and 2010 with the number of new Commercial/Industrial connections assumed for 2009 and 2010 in Exhibit 2.

Response:

See response to Energy Probe IR#13. The same situation exists with GS customers. Intermediate however, we are not predicting in the capital budget that there will be any additional intermediate class of customers.

Question #12

Reference: Exhibit 3/Tab 2/Schedule 1, Attachment 1

a) Please provide a breakdown of the $78,810 in transformer allowance by customer class.

Response:

The transformer allowance is for the GS>50 to 2,999 kW customer class.

b) Please provide a revised version of the Schedule on page 1 showing 2010 Projected Revenues at Existing rates where the volume for the GS>50 and Intermediate classes include the volumes associated with the Embedded Distribution delivery points that are currently not subject to volumetric charges.

Response:
EPL did not prepare a 2010 forecast of kW volumes for these Embedded Distribution volumes and thus cannot produce a projection of 2010 revenue at existing rates on this basis.

c) With respect to the Table on page 2, please provide a schedule setting out the derivation of the revenue by class for 2010 used to determine the Total % of Revenue by Class shown in the last column. Please provide the results in sufficient detail to support the reported Fixed-Variable splits by class.

Response:
Please refer to the second table on page 1 ("2010 Projected Revenues at Existing Rates")

The revenues used to determine the Fixed/Variable split by class appear under the columns labeled "Fixed Charge Revenue" and "Variable Charge Revenue".

The revenues used to determine the Total % of Revenue by Class appear under the last column. Revenue for each class is divided by the "Gross Revenue (before Transformer Allowances)" of $10,623,723.

d) Please confirm whether the rates used in response to part (c):
- Excluded the Smart Meter adder
- Exclude the LV adder
- Included the discount for Transformer Allowance where appropriate.

If not, please provide a revised response to part (c) using the rates as specified above.

Response:
The rates by class used in response to part [c] did not include the Smart Meter adder, but did include the LV adder and recovery of Transformer Allowances as suggested in the presentation of the second table on page 1.

The following table restates the response to part [c] excluding the LV adder and Transformer Allowance recoveries, based on the data presented in Exhibit 7 / Tab 2 / Schedule 2 / Attachment 3:

2010 Projected Revenue at Existing Rates	Net Distribution Revenue *(A)*	Fixed Charge Revenue *(B)*	Fixed % *(C)*	Variable % *(D)*	Total % *(E)*
Residential	6,997,759	3,391,090	48.46%	51.54%	71.98%
General Service Less Than 50 kW	530,001	278,911	52.62%	47.38%	5.45%
General Service 50 to 2,999 kW	1,856,278	911,434	49.10%	50.90%	19.09%
General Service 3,000 to 4,999 kW	178,584	97,432	54.56%	45.44%	1.84%
Unmetered Scattered Load	63,107	16,091	25.50%	74.50%	0.65%
Sentinel Lighting	7,207	2,808	38.96%	61.04%	0.07%
Street Lighting	88,353	35,025	39.64%	60.36%	0.91%
TOTAL	**9,721,289**	**4,732,791**	**48.68%**	**51.32%**	**100.00%**

(A) Exhibit 7 / Tab 2 / Schedule 2 / Attachment 3
(B) Exhibit 3 / Tab 2 / Schedule 1 / Attachment 1, page 1
(C) = (B) / (A)
(D) = 1 - (C)
(E) Class Revenue from column (A) divided by Total from column (A)

Question #13

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

a) Please reconcile the $779,844 in Other Revenue reported here (page 1) with the $779,884 value reported in the accompanying Attachment 1 (page 1) and the $679,883 value reported in Exhibit 1/Tab 4/Schedule 9, page 4.

Response:

Exhibit 3, Tab 3, Schedule 1, page 1 sets out the total Other Revenue Essex is forecasting, including non-distribution revenues. Exhibit 1, Tab 4, Schedule 9, page 4 only sets out other distribution revenue to be deducted to determine the Revenue Requirement. In other words, the amounts included in accounts 4375 and 4380 (revenues and expenses from non-regulated, non-distribution activities) were excluded from Exhibit 1, Tab 4, Schedule 9, page 4. The exclusion of 4375-4380 is consistent with the OEB's 2006 EDR model, where those accounts were not included in the revenue offsets calculated on sheet 5-5, and there has been no change or guidance to the contrary from the OEB since that model was issued.

b) With respect to Attachment 2 (page 1), please explain the inclusion of $78,810 in Transformer Allowance under Revenues from Services.

Response:

The inclusion of $78,810 for Transformer Allowance under Revenues from Services was an error and will be removed from the filing.

c) With respect to Attachment 2 (page 1), please explain why there is roughly a $200,000 difference between Revenue and Expenses for Non-Utility Operations in 2008 but a difference of only $100,000 forecast for 2009 and 2010.

Response:

Essex has reduced the revenues and corresponding expenses from the towns for billing services by a net affect of $100,000 in anticipation that at least one of the towns will not be contracting from Essex for this service. Essex felt that since this situation (see response to 13 a)) has no affect on the revenue requirement, it did not require explanation.

OPERATING COSTS

Question #14

Reference: Exhibit 4/Tab 1/Schedule 1, pages 5-6

a) The Application states that the forecasted 2010 OM&A is 3% lower than the 2006 Board approved level. However, the Application goes on to state that $901,414 in LV costs should be removed from the 2006 approved OM&A for comparative purposes. Please confirm that based on this adjustment the 2010 forecast OM&A is 12% above the comparable 2006 EDR approved value.

Response:

Essex agrees that with the removal of the $901,414 in LV costs from the 2006 approved OM&A amounts, the 2010 forecast OM&A costs are 12% higher. However, taking into consideration the fact that the 2006 EDR approved values were based on an average of 2003 & 2004 costs this 12% increase represents a 2% increase per year for the past 6 years which is below the posted CPI rates.

b) With respect to page 6, the referenced Appendix 2-H lists a number of cost drivers for 2009 (i.e., Regulatory Expenses through Community Relations). For each item please explain what it represents and why it is considered an ongoing cost for 2010.

Response:

Regulatory Expense – this represents 25% of the total cost to complete the rate filing and will continue until 2012.
IFRS – this represents 25% of the total cost to complete the requirements to become IFRS compatible and will continue until 2012
UG Services/UG Cond &Devices/UG Distn Transfrmr/Pole Maintnce /Resource Planning – Due to a number of municipal infrastructure projects and the impending Detroit River International Crossing project, which are expected to span 3 to 4 years, these costs are expected to increase significantly and stay at that level for 3 to 4 years.
Health & Safety - EPL's top priority for the health and safety of its workers and to pursue the Electrical & Utilities Safety Association (EUSA) pursuit of ZeroQuest which represents zero injuries and illness, these are the costs associated with obtaining and maintaining these initiatives.
Community Relations - this includes CD&M expenses and Essex is forecasting that the $20,000 increase seen in 2009 will be maintained through out the next 3 years.

c) With respect to page 6 and Appendix 2-H, where in the cost driver table are the annual inflation of 3% for wages and 2% for other expenses (per Exhibit 4/Tab 1/Schedule 3, page 1) captured?

Response:

The 3% inflation for wages would be in the Labour & Benefits line in Appendix 2-h, while the 2% inflation for other expenses would be included in each individual line (i.e. tree trimming, customer locates, etc.)

d) Why isn't EPL recording its 2010 IFRS cost in a deferral account as provided by the Board in EB-2008-0408, page 43?

Response:

See response to Energy Probe IR# 11L.

Question #15

Reference: Exhibit 4/Tab 2/Schedule 2

a) What is the basis for the $200,000 estimate for IFRS conversion costs? Is this over and above the software capital spending to enable implementation of IFRS?

Response:

See also response to Board Staff IR# 10. This amount is over and above the software capital requirements.

Question #16

Reference: Exhibit 4/Tab 2/Schedule 4

a) Given the Board's September 28, 2009 update regarding the Low Income Energy Assistance Program initiative:
   - Is the budgeted LEAP amount required for 2010? If yes, why?
   - Is the proposed CIS department funding required for 2010? If yes, why?

Response:

Due to the Board's September 28, 2009 update, the $18,002.80 for the Low Income Energy Assistance Program is not required. The proposed CIS department funding of approximately $7,000 was non incremental cost and therefore was not included as an additional cost in the rate filing.

Question #17

Reference: Exhibit 4/Tab 2/Schedule 5

a) Please confirm that EPL has included the cost of the two new positions in the 2010 proposed revenue requirement as opposed to posting them to the requested deferral accounts.

Response:

Essex is not posting the cost of the 2 new positions to the requested deferral accounts as these costs are known. The deferral accounts requested were for unknown and yet to be determined system costs.

Question #18

Reference: Exhibit 4/Tab 4/Schedule 1

a) The Application states (page 6) that, in the past, the accounting department of EPC assisted with required regulatory activities as did other positions within EPL. Please explain why, with the hiring of the Manager-Regulatory Affairs, the charges from EPC for Finance & Regulatory & Management (per Appendix 2-M) are virtually the same in 2010 as in 2008 and 2009.

Response:

See also response to Energy Probe IR# 32 c). The charges will not change as the transition to and the ongoing requirement of IFRS will replace the regulatory charges.

b) The Application states (page 9) generator requests for studies and associated models have previously been completed by consultants and will now be done in-house. Please indicate where in the Application the reduction in external consultants' costs for 2010 has been reflected.

Response:

Essex had been requested to complete 3 CIA studies for generators in 2008. A consultant was hired to complete these CIA's and the generator was charged to recover these consultant fees. The costs were placed under a recoverable account which is a "pass through" to Essex. Therefore this amount would not show up in Essex's application. These potential revenue offsets have not been included in the applications as it could not be estimated.

Essex requested a consultant complete some studies of its system in 2006 to model Essex's distribution system. These charges went to Account 5085 Miscellaneous Distribution Expense and a reduction from 2006 to 2007 can be seen in Exhibit 4 Tab 2 Schedule 1 Attachment 2 Page 1 of 3.

c) To what extent will the costs of the new Distribution Engineer and Special Customer Accounts Manager position be recovered from generators through charges for connections studies, etc.? Where is this revenue offset reflected in the Application?

Response:

Essex expects to recover approximately 38% of the Distribution Engineers cost from generators. Essex expects approximately 17% of The Special Customer Accounts Manager cost is recoverable from generators. The remainder may be recovered through Smart Grid activities as described below. No revenue offset was included in the application.

Response below is also in your question 6d).

Essex has not developed an overall plan based on the OEB's Guidelines: Deemed Conditions of Licence on Distribution System Planning (G-2009-0087) and the recent amendments to the Distribution System Code effective October 21, 2009. An excerpt from page 5 of the Deemed conditions:

"To allow distributors to begin recording expenditures for certain activities relating to the accommodation of renewable energy or the development of a smart grid, the Board is creating four new deferral accounts in the Uniform System of Accounts. These deferral accounts are authorized to be used to record the qualifying incremental investments or expenses, respectively that are described in sections 1 and 2 below. In this context, incremental means that an investment was not included in previous capital plans approved by the Board and/or is not funded through current rates."

The changes to the DSC code describe how Capital Contributions will be treated for generation expansion. Please refer to the DSC on the OEB's web site under Distributed Generation Connection Cost Responsibility. Essex will follow the DSC therefore not all capital costs would be recovered from the generator. The costs not recovered from the generators will be placed in variance and reviewed and approved by the Board for recovery by some other means.

Question #19

Reference: Exhibit 4/Tab 5/Schedule 1

a) Please describe the Finance, Regulatory and Management services that EPC will provide to EPL in 2010.

Response:

The primary services provided are listed below are not intended to be all encompassing as the requirement for services can change with industry influences.

Finance – cash management, financing (loan and banking) arrangements, financial reporting including budgeting, monthly statements and associated reporting, preparation for board meetings, tax advice and management, financial management of processes and procedures, year end closing processes including completing the year end audit, review and documentation of internal processes, systems and procedures, provide services for conversion to IFRS, management of accounting staff, provide accounting support to engineering dept. provide support for negotiations,

Regulatory – This function will be performed by the Manager, Regulatory Affairs within EPL. Until the position is filled or if it is not approved, the regulatory services to be provided are:

1) Collection and review of statistical information including billing and consumption including unbilled revenue
2) Load forecasting
3) Retailers - agreements, statistics, prudential reviews
4) RRR filings
5) Regulatory assets and liabilities accounting
6) Respond to OEB requests for information
7) Smart meter regulation, implementation and associated OEB filings
8) ESQR collection of data, analysis and reporting

9) Review and advise on OEB initiatives, consultations
10) Participate in OEB consultations
11) Annual IRM rate filings
12) Cost of service applications
13) GEGEA requirements
14) Participate in EDA councils
15) IESO regulatory requirements and filings
16) OPA programs
17) CDM programs
18) OEFC audit requirements

Management services – strategic planning management, policy development and support, legal, information management services, information technology services, corporate administration, new business development, advice and guidance on GEGEA initiatives and legislation, Human Resources services, Benefits administration, and communication services.

b) Please describe the Engineering & CDM/OPA services that EPC will provide to EPL in 2010. Are any of these costs recoverable through OPA program funding and, if not, why not?

Response:

The engineering services to be provided are for advice and guidance with respect to system planning and capital projects. The CDM/OPA services provided will be for administration of OPA projects and CDM activities required by the OEB. The specific CDM activity has not been determined yet since targets have not been released by the OEB. The OPA programs are cost recoverable and these amounts were recorded as revenues in account 4375. See Exhibit 3, Tab 3, Schedule 1, Attachment 2.

c) Please indicate where (i.e., which USOA) the external costs for managing CDM/OPA activities were recorded prior to 2010.

Response:

They were recorded in account 4380 Expenses of Non-Utility Operations.

d) In which USOA are the charges from EPC recorded for 2010?

Response:

EPC charges are included in accounts 4380 Expenses of Non-Utility Operations for CDM/OPA activity, 5610 Management Salaries and Expenses, and Engineering charges related to capital are included in the appropriate capital 1800's accounts.

e) With respect to page 1, please confirm that the 6% is a mark-up on the allocated OM&A expense. If this is the case, why is it reasonable to a compare the value to EPL's regulated rate of return which is applicable to the value of assets employed?

Response:

The 6% return on invested capital was applied to the expenses incurred. The affiliate code section 2.3.4.1 states: "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 average cost of capital." The 2008 weighted average cost of capital for EPL was 7.64%. The 6% has always been lower than EPL's weighted average cost of capital and we feel is reasonable.

Question #20

Reference: Exhibit 4/Tab 8/Schedule 3, page 2

a) Please provide the basis for EPL's combined 2010 tax rate of 33.73%.

Response:

The effective rate should have been 31%. See response to Board Staff IR#18 a).

b) Does EPL's 2010 tax rate reflect the May 2009 provincial budget changes that, effective July 1, 2010, will reduce the small business tax to 4.5% and eliminate the small business deduction surtax and reduce the corporate tax rate to 12%? If not, please provide an updated tax calculation. (Note: This is similar to Board Staff IR #18 but also includes reference to the corporate tax reduction)

Response:

See response to Board Staff IR#18a and b.

REVENUE DEFICIENCY

Question #21

Reference: i) Exhibit 6/Tab 1/Schedule 2

a) Based on the responses to the first round of interrogatories from all parties please prepare a schedule that sets out all the adjustments/revisions that EPL has acknowledged as being required to the currently requested 2010 revenue requirement and the impact of each. In each case, please provide a cross reference to the relevant IR response.

Response:

A revised rate model based on the responses to the first round of interrogatories from all parties will be filed by December 23 and a summary of impacts to the revenue requirement will be submitted at that time.

COST ALLOCATION

Question #22

Reference: Exhibit 7/Tab 1/Schedule 1, Attachment 1 (ERA Report),

a) With respect to page 7 (lines 10-12), please confirm that the reference to GS<50 should read "GS>50". If not, please explain.

   Response:

   Yes, the reference to GS<50 should read GS>50.

b) With respect to Table 7, please recalculate the revenue to cost ratios for EPL-2010 assuming the distribution revenues for each class are increased by the same percentage such that total service revenues (i.e., including miscellaneous revenues) equals the 2010 proposed revenue requirement ($12,192,424).

   Response:

Customer Class	EPL-2006	EPL-2006C1	EPL-2006C2	EPL-2010	EPL-2010 assuming uniform	Board Target

					increase	Range
Residential	115.53	116.72	104.24	85.36	100.40	85-115
GS < 50 kW	47.76	48.2	46.36	41.45	49.16	80-120
GS > 50 kW	155.58	150.26	146.05	136.30	159.37	80-180
USL	129.66	129.38	143.6	114.39	137.28	80-120
Street Lighting	11.84	11.92	32.2	26.45	30.92	70-120
Sentinel	29.9	30.38	40.16	31.39	36.70	70-120
Intermediate	173.49	163.17	163.42	288.78	337.06	80-120
Total	100.00	100.00	100.00	85.08	100.00	

c) With respect to page 7 and the load profile for the one Intermediate customer, it was acknowledged in Exhibit 3 that the load for this customer varies significantly. Why wouldn't an average profile based on few years of data be a better basis for forecasting 2010. Please provide a table that contrasts the load profile (e.g., kWh, CP and NCP values) based on: i) 2008 data and ii) based on an average 2006-2008 data).

Response:

In Exhibit 3/Tab 1/Schedule 2, Attachment 1, p.9, it was acknowledged that consumption for this customer is irregular on a month-to-month basis. However, Table 8 of E3/T1/S2, Attachment 1 clearly shows declining annual consumption since 2005. Consumption peaked in 2005 and has been steadily declining since. Comparing 2008 to 2005, kWh consumption has declined by 31% (3,087,555 vs. 4,511,151) and kW consumption has declined by 41% (19,537 vs. 33,136). Using an average over this period would likely significantly overstate 2010 consumption. In fact, there is significant risk in using 2008 data, which is an optimistic assumption. Examining year-to-date kWh consumption, consumption in the 12-month period November 2008 to October 2009 is 31% lower than consumption in the November 2007 to October 2008 period (2,120,460 vs. 3,087,555). In fact, it has come to our attention that the customer has cut production by 30% and moved this production to a US facility. This is consistent with the decline we see in 2009 compared to 2008. This also illustrates how inappropriate using a 2006-2008 average is.

With respect to the last sentence of the question, significant effort would be required to reconstruct load profiles, just in order to provide a response to a premise which is not reasonable as noted in the above paragraph. Under these circumstances, EPL declines to produce the requested table at this time.

d) Please provide a schedule setting out the derivation of the Distribution Revenue by Customer Class as shown in Sheet O1 (Row 18) of the 2010 Cost Allocation run. (Note: The values used for each customer class do not match those reported in Exhibit 7/Tab 2/Scheduele 2/Attachement 3, page 1)
Response:

The total forecast 2010 Distribution Revenue at existing rates in Sheet O1 (row 18) of the 2010 Cost Allocation run matches the total reported in Exhibit 7 / Tab 2 / Attachment 3. EPL agrees that the revenues for each customer class should also match. The difference arose from different assumptions used to deduct Transformer Allowances recoveries and Low Voltage Charges (that are embedded in distribution rates) from each class' distribution revenue, since the RateMaker model did not include a breakdown of these amounts at existing rates by customer class (see Exhibit 3 / Tab 2 / Schedule 1 / Attachment 1).

However, EPL notes that this inconsistency does not impact the revenue responsibility percentages by rate class obtained from the Cost Allocation model. The revenue-to-cost ratios shown for EPL-2010 would be slightly impacted, but these ratios were provided for informational purposes only. The Revenue-to-Cost ratios used as the starting point to determine 2010 ratios were those generated from the EPL-2006C2 Cost Allocation model, which reflects the latest Board-approved figures (with appropriate corrections).

e) With respect to Table 8, the revenue requirement dollar values shown for the Residential class do not match the value in the Cost Allocation models filed with the application. Also, the total costs reported for the 2006 model runs do not match those in the actual Cost Allocation models filed. Please reconcile and revise Table 8 as required.

Response:

Table 8 in the ERA Report does not align as intended with the Cost Allocation models filed with the application. The following table, which properly reflects the filed models, should be used instead:

Customer Class	EPL-2006		EPL-2006C1		EPL-2006C2		EPL-2010	
	$	%	$	%	$	%	$	%
Residential	6,437,830	61.57	6,372,347	61.57	7,191,729	69.48	8,589,516	70.45
GS< 50 kW	1,416,539	13.55	1,403,645	13.56	1,429,751	13.81	1,614,377	13.24
GS > 50 kW	1,272,170	12.17	1,252,517	12.10	1,290,781	12.47	1,487,916	12.20
USL	53,713	0.51	53,828	0.52	46,659	0.45	59,655	0.49
Street Lighting	1,162,213	11.12	1,154,907	11.16	286,042	2.76	357,021	2.93
Sentinel	28,942	0.28	28,484	0.28	20,899	0.20	23,822	0.20
Intermediate	84,157	0.80	84,621	0.82	84,490	0.82	60,117	0.49
Total	10,455,564	100.00	10,350,350	100.00	10,350,350	100.00	12,192,424	100.00

Question #23

Reference: Exhibit 7/Tab 2/Schedule 2, Attachment 1

a) Please provide a schedule that sets out the derivation of the values in the column “Cost Allocation %” (i.e., the first column with numerical values).

Response:

The derivation is shown on sheet F3 of the RateMaker model filed with the application.

b) Please reconcile the 69.98% value for the Residential class’ share of Base Revenues at existing rates with the 70.50% value implicit in Sheet O1 of the 2010 Cost Allocation run (i.e. 6,853,984/9721,288).

Response:

See response to Question #22 (d)

c) The Table indicates that for 2010 the Cost Allocation of Base Requirement to the Residential class is $8,086,704 but that the Existing Rate portion of the Base Revenue Requirement is only $8,056,690.

- Please confirm that this suggests a revenue to cost ratio for the class of less than 100% at existing rates.

- Please reconcile this with the results presented in Exhibit 7/Tab 1/Schedule 1/Attachment 1, page 14 where at existing rates the revenue to cost ratio for Residential (85.65%) exceeds the overall ratio (85.31%) suggesting that at current rates the revenue to cost ratio for Residential exceeds 1.0.

Response:

The revenue to cost ratio for the Residential class would be less 100% if the 2010 Base Revenue Requirement were to be allocated in the same proportions that would be expected for 2010 at existing rates.

The results presented in Exhibit 7 / Tab 1 / Schedule 1 / Attachment 1 page 14 present the ratios on the basis of the Service Revenue Requirement (including Miscellaneous Revenue), rather than the Base Revenue Requirement. The impact of Miscellaneous Revenue on revenue to cost ratios is typically negligible; it is mere coincidence in this instance that the difference straddles unity (0.9963 vs 1.0040)

EPL submits the difference remains immaterial to its proposed revenue allocation, having used the results of the EPL-2006C2 file as the proposed starting point for determining its proposed revenue-to-cost ratios for 2010. The ratios from that file were based on Board-approved rates, loads and cost allocation methodology, with appropriate corrections. The ratio for Residential from that Cost Allocation file was clearly above 1.0 (104.24%).

d) The Table indicates that for 2010 the Cost Allocation of Base Requirement to the Residential class is $8,086,704 but that the Existing Rate portion of the Base Revenue Requirement is only $8,056,690. If this is the case, why is EPL proposing to increase the revenue allocation to $8,295,250 – which exceeds the "Cost Allocation" value?

Response:

As noted in the response to part [c] above, EPL considers the revenue-to-cost ratio from the EPL-2006C2 file to be the appropriate starting point, and on this basis is proposing a decrease in the Residential revenue to cost ratio from 1.04 to 1.00 by 2012 (see Exhibit 7 / Tab 2 / Schedule 2).

e) Please confirm that the proposed Revenue to Cost ratios are calculated based on the ratio of the "Base Distribution Revenue by Class" to the "Allocated Base Distribution Revenue Requirement by Class" – where both total $11,512,541 when summed over all classes.

Response:

Correct.

f) Please confirm that in the Board's Cost Allocation Model Revenue to Cost Ratios are determined base on the ratio of "Total Revenues by Class (including allocated Miscellaneous Revenues)" to the "Allocated Service Revenue Requirement by Class" – where both total $12,192,424 when summed over all classes.

Response:

Correct. As noted in the second paragraph of the response to part [c] above, EPL submits that the impact of Miscellaneous Revenue, being the difference between the Service Revenue Requirement and the Base Revenue Requirement, is negligible and immaterial to the application.

g) Please calculate the revenue to cost ratios for each class based on EPL's proposed allocation of costs consistent with the methodology used by the Board's cost allocation model.

Response:

The following table incorporates Miscellaneous Revenues in order to derive revenue to cost ratios on the basis of the Service Revenue Requirement, consistent with the methodology used by the Board's cost allocation model.

	REVENUE ALLOCATION		
	Base Revenue Allocation	Miscellaneous Revenue	Service Revenue Allocation
Residential	8,295,250	502,812	8,798,062
General Service Less Than 50 kW	976,875	88,009	1,064,885
General Service 50 to 2,999 kW	1,940,105	71,781	2,011,886
General Service 3,000 to 4,999 kW	84,607	1,968	86,574
Unmetered Scattered Load	60,253	9,444	69,698
Sentinel Lighting	11,023	381	11,404
Street Lighting	144,427	5,488	149,915
TOTAL	**11,512,541**	**679,883**	**12,192,424**

	COST ALLOCATION		
	Base Revenue Allocation	Miscellaneous Revenue	Service Revenue Allocation
Residential	8,086,704	502,812	8,589,516
General Service Less Than 50 kW	1,526,368	88,009	1,614,377
General Service 50 to 2,999 kW	1,416,135	71,781	1,487,916
General Service 3,000 to 4,999 kW	58,149	1,968	60,117
Unmetered Scattered Load	50,211	9,444	59,655
Sentinel Lighting	23,441	381	23,822
Street Lighting	351,533	5,488	357,021
TOTAL	**11,512,541**	**679,883**	**12,192,424**

	REVENUE TO COST RATIOS		
	Base Revenue Allocation	Miscellaneous Revenue	Service Revenue Allocation
Residential	1.03	1.00	1.02
General Service Less Than 50 kW	0.64	1.00	0.66
General Service 50 to 2,999 kW	1.37	1.00	1.35
General Service 3,000 to 4,999 kW	1.46	1.00	1.44
Unmetered Scattered Load	1.20	1.00	1.17
Sentinel Lighting	0.47	1.00	0.48
Street Lighting	0.41	1.00	0.42
TOTAL	**1.00**	**1.00**	**1.00**

Question #24

Reference: Exhibit 7/Tab 2/Schedule 2, Attachment 2

a) This schedule indicates that the revenue to cost ratio for Residential is being reduced in 2010. However, Attachment 1 shows that the revenues allocated to the Residential class under EPL's proposal are higher than what would be case if the existing rate proportions were maintained – suggesting the revenue to cost ratio is being increased. Please reconcile.

Response:

Please see response to #23 [d].

RATE DESIGN

Question #25

Reference: Exhibit 8/Tab 2/Schedule 1/Attachment 1, page 1

a) Please confirm that EPL's approach to rate design is as follows:
- Maintain the current fixed-variable split, except
- Where the current fixed charge exceeds the Board's upper bound, set the fixed charge at the value for the upper bound.

Response:

EPL's approach to rate design is as stated above.

b) Please confirm whether the total Revenue Requirement used to determine allocation of cost to customer classes and resulting the monthly service charges under the "Existing Fixed/Variable Split" column is:
- $12,575,503 (per Exhibit 8/Tab 1/Schedule 1, page 1), or
- $11,512,541 (per Exhibit 7/Tab 2/Schedule 2, Attachment 1

If the former, please explain why when the Cost Allocation model used to determine the range service charges excludes LV costs and the transformer allowance credit.

Response:

The total revenue amount allocated to customer classes for purposes of setting distribution rates is $12,575,503. The Cost Allocation model is used in the allocation of the Base Revenue Requirement (BRR). The 'Gross Base Revenue Requirement' of $12,575,503 includes the BRR, transformer allowance recoveries and LV charges. These are not considered in the Cost Allocation model, rather specific allocations of these amounts are made to each class as shown on sheet F4 of the RateMaker model: transformer allowance recoveries are allocated entirely to the GS 50-2,999 kW class (which receives all allowances), while LC charges are allocated in proportion to the Transmission-Connection revenue projected for each customer class.

c) If the response to part (b) indicates that the $11,512,541 value was not used, please re-calculate the service charge based on the existing fixed/variable split underlying Base Distribution Revenues (per response to Question 12, part (d)) and the proposed allocation of the Base Distribution Revenue Requirement to customer classes (per Exhibit 7/Tab 2/Schedule 2, Attachment 2, page 2).

Response:

Please see the following table:

	Base Revenue @ Existing Rates	Fixed Charge Rev. @ Existing Rates	% Base Revenue from MSC
Residential	6,997,759	3,391,090	48.46%
General Service Less Than 50 kW	530,001	278,911	52.62%
General Service 50 to 2,999 kW	1,856,278	911,434	49.10%
General Service 3,000 to 4,999 kW	178,584	97,432	54.56%
Unmetered Scattered Load	63,107	16,091	25.50%
Sentinel Lighting	7,207	2,808	38.96%
Street Lighting	88,353	35,025	39.64%
TOTAL	**9,721,289**	**4,732,791**	**48.68%**

	Base Revenue Requirement (BRR)	% Base Revenue from MSC	BRR from Fixed Charges
Residential	8,295,250	48.46%	4,019,849
General Service Less Than 50 kW	976,875	52.62%	514,078
General Service 50 to 2,999 kW	1,940,105	49.10%	952,593
General Service 3,000 to 4,999 kW	84,607	54.56%	46,160
Unmetered Scattered Load	60,253	25.50%	15,363
Sentinel Lighting	11,023	38.96%	4,295
Street Lighting	144,427	39.64%	57,254
TOTAL	**11,512,541**	**48.68%**	**5,604,859**

	BRR from Fixed Charges	Customers / Connections	Annual Fixed Charge Amount	Monthly Service Charge
Residential	4,019,849	25,902	$155.19	$12.93
General Service Less Than 50 kW	514,078	1,852	$277.58	$23.13
General Service 50 to 2,999 kW	952,593	222	$4,290.96	$357.58
General Service 3,000 to 4,999 kW	46,160	2	$23,079.78	$1,923.32
Unmetered Scattered Load	15,363	151	$101.74	$8.48
Sentinel Lighting	4,295	168	$25.56	$2.13
Street Lighting	57,254	2,643	$21.66	$1.81
TOTAL	**5,604,859**			

d) Please confirm that the Board's EB-2007-0667 Guideline (page 12) sets the upper limit for the MSC at 120% of avoided costs plus the allocated customer costs (i.e., Minimum System plus PLCC Adjustment).

Response:

EPL does not believe that the guideline sets the upper limit for the MSC as stipulated in the question. The Board noted in its report that such a limit had been proposed by Board staff, but added "The Board considers it to be inappropriate to make significant changes to the ceiling for the MSC at this time". Thus EPL has relied on the maximum value generated from the Board's approved Cost Allocation model as the ceiling for the MSC. Furthermore, the guideline also states that "Distributors that are currently above this value are not required to make changes to their current MSC to bring it to or below this level". Thus the existing MSC rate constitutes the effective ceiling, when it exceeds the maximum value from the Cost Allocation model.

e) Based on the responses to parts c) and d), please indicate any revisions that are required to EPL's proposed 2010 monthly service charges.

Response:

EPL does not believe that any revisions are requirement to its proposed 2010 monthly service charges. EPL submits that the proposed MSC are consistent with Board guideline EB-2007-0667, and that the inclusion of LV charges and transformer allowance recoveries determining fixed/variable splits for each customer class is appropriate and in any event immaterial to the resulting proposed MSCs.

Question #26

Reference: Exhibit 8/Tab 2/Schedule 1/Attachment 2

a) Please confirm that the rates set out in this attachment provide for the recovery of LV costs and the foregone revenues associated with the transformer ownership allowance.

Response:

Yes. The total proceeds from distribution charges in this table reflects the Gross Revenue from Distribution Charges, which includes the Base Revenue Requirement, LV charges and recoveries of transformer allowances.

b) Please provide a revised rate derivation where:
    - Fixed and variable charges are first established to recovery the Base Distribution Revenue Requirement (per Question #25),
    - LV adders (as calculated in Exhibit 8/Tab 3/Schedule 2) are incorporated into each class' variable rates.
    - The variable rates for each class where customers receive the transformer allowance are increased to recovery the allowance specifically provided to the class' customers.

Response:

The fixed charge levels under this scenario would be the same as those shown in the response to #25 part [c].

EPL's approach to revenue allocation and rate design assumed Gross Revenue from Distribution Charges that included transformer allowance recoveries allocated entirely to the GS 50-2,999 kW class (which receives all such credits), as well as LV charges. As such, variable charges under this scenario can be derived by taking the Gross Revenue from Distribution Charges, subtracting the Base Revenue Requirement from Fixed Charges calculated in the response to #25 part [c], and dividing the result by the applicable volume metric, as shown in the following table:

	Gross Revenue from Distribution Charges	BRR from Fixed Charges	Gross Revenue from Variable Charges
Residential	8,817,317	4,019,849	4,797,468
General Service Less Than 50 kW	1,107,098	514,078	593,021
General Service 50 to 2,999 kW	2,323,088	952,593	1,370,495
General Service 3,000 to 4,999 kW	99,462	46,160	53,303
Unmetered Scattered Load	63,157	15,363	47,793
Sentinel Lighting	11,586	4,295	7,291
Street Lighting	153,794	57,254	96,539
TOTAL	**12,575,503**	**5,609,592**	**6,965,910**

	Gross Revenue from Variable Charges	Volume (kWh's / kW's)	Distribution Volumetric Rate
Residential	4,797,468	271,379,498	$0.0177
General Service Less Than 50 kW	593,021	72,012,960	$0.0082
General Service 50 to 2,999 kW	1,370,495	467,092	$2.9341
General Service 3,000 to 4,999 kW	53,303	19,537	$2.7283
Unmetered Scattered Load	47,793	1,605,371	$0.0298
Sentinel Lighting	7,291	1,076	$6.7761
Street Lighting	96,539	18,024	$5.3562
TOTAL	**6,965,910**		

Question #27

Reference: Exhibit 8/Tab 3/Schedule 1

a) With respect to the discussion regarding the Network and Connections accounts' variances and balances, please confirm that part of the issue is that historically retail rates have not be readjusted at the same time as the rates charged by Hydro One Networks changed. To what extent did this account for the 13% under recovery experienced with the Network account and the 31% under recovery in the Connections account in the last 12 months?

Response:

Essex confirms the statement that part of the issue is the fact that historically the retail rates have not been readjusted at the same time as the rates charged by Hydro One. Essex feels this accounted for the majority of the under recovery in both Network and Connections in the last 12 months.

Question #28

Reference: Exhibit 8/Tab 3/Schedule 2

a) Given Hydro One Networks is proposing to increase is ST rates January 1, 2010, is EPL's proposal regarding LV charges still appropriate?

Response:

Essex feels that based on the actual information it had at the time of the filing the LV charges it is proposing are appropriate. Since Hydro One's rates have not yet been approved it would not be correct to include these proposed rates in our filing.

DEFERRAL/VARIANCE ACCOUNTS

Question #29

Reference: Exhibit 9/Tab 1/Schedule 2, Attachment 1

a) Please explain what the balance in Account #1572 - Extra-Ordinary Event costs represents (e.g., why/how were the costs incurred and why are they included in a deferral account?).

Response:
The balance in Account 1572 – Extra-Ordinary Events represents the costs incurred to restore power after a wind storm in September, 2005. These costs were included in this variance account because they met the accounts criteria of: unique in nature; out of management control; and over our materiality limit.

Question #30

Reference: Exhibit 9/Tab 2/Schedule 1

a) Why is EPL proposing to dispose of the balance the Deferred Payments in Lieu of PILs account (#1562) when the treatment of PILs is currently the subject of a separate proceeding (EB-2008-0381)?

Response:

Essex is not proposing to dispose of the balance in the Deferred Payments in Lieu of PILs account (#1562) as stated in Exhibit 9, Tab 2, Schedule 1.

b) Please demonstrate that EPL's Deferral and Variance account balances meet the criteria for disposition as set out in the Board's EB-2008-0046 Report.

Response:

Essex's Deferral and Variance account balances meet the criteria for disposition as the net balances of all account balances when unitized are higher than $0.0001/kWh or $0.0001/kW.

SMART METERS

Question #31

Reference: Exhibit 9/Tab 3/Schedule 2

a) Please reconcile the $5,297,682 cost reported on page 3 with the costs reported in Exhibit 9/Tab 3/Schedule 1, Attachment 1.

Response:

The Exhibit 9/Tab 3/Schedule 1/Attachment 1 Appendix 2-S Smart meter deferral account table has been revised as shown below. The previous version contained the stranded meter cost in the capital column and was removed.

Also included is a revised Exhibit 9/Tab 3/Schedule 2/Attachment 1 for smart meters. The Exhibit was revised to correct CCA misclassifications, correct the short term debt interest rate and some other minor errors in the worksheets. The variance between Appendix 2-S for capital of $4,477,186 and $5,294,105 on page 1 of the revised smart meter worksheets is the non incremental labour ($816,919) used to install the small meters. This labour amount has not been included elsewhere in the rate base so it has been included as part of the smart meter adder calculation to ensure this cost is included at least once in the rate application.

Essex Powerlines EB-2009-0143

Appendix 2-S
Smart Meters

Year	Smart meters Installed			% of customers converted	Account 1555			Account 1556
	Residential	GS<50	Other		Funding Adder Revenues Collected	Cap Exp	Stranded meter costs	Op Exp
2006	-	-	-	0.0%	44,860	-		-
2007	1,453	-	-	0.0%	82,769	248,654		
2008	-	-	-	0.0%	92,272	812	60,041	6,088
Est 2009*	15,465	430	-	53.4%	216,729	2,304,100	353,351	67,307
Est 2010*	10,215	1,420	-	95.0%	302,136	1,923,620	374,104	91,642
Total	27,133	1,850	-		738,766	4,477,186	787,496	165,037

* estimated amounts

Smart Meter Costs

2010 EDR Data Information		
Third-party long-term debt	56.0%	
Deemed long-term debt		
Short-term debt	4.0%	
Deemed Equity	40.0%	
Third-party long-term debt rate	5.56%	*see BS IR# 21a*
Deemed long-term debt rate	0.00%	
Short-term debt rate	1.33%	*see BS IR# 19*
Return on Equity	8.01%	
Weighted Average Cost of Capital	6.37%	

2010 Tax Rate	
Corporate Income Tax Rate	31.00%
Capital Tax Rate	0.075%

Capital Data:	1-Jan-07 to 31-Dec-08	1-Jan-09 to 31-Dec-09	1-Jan-10 to 31-Dec-10	Total
Smart meter including installation	$ 239,621	$ 2,647,950	$ 2,352,389	$ 5,239,960
Tools and Equipment (Work force management)		$ 9,300	$ -	$ 9,300
Computer Hardware Costs	$ 9,845		$ -	$ 9,845
Computer Software		$ 35,000	$ -	$ 35,000
Total Capital Costs	$ 249,466	$ 2,692,250	$ 2,352,389	$ 5,294,105

LDC Amortization Policy:		
Smart Meter Amortization Rate	$ 15	Years
Tools and Equipment (Work force management)	$ 10	Years
Computer Hardware Amortization Rate	$ 5	Years
Computer Software Amortization Rate	$ 5	Years

Operating Expense Data:	1-Jan-09 to 31-Dec-10
Incremental OM&A Expenses	$ 91,642
Total Incremental Operating Expense	$ 91,642

Smart Meter Revenue Requirement Calculation 2010

Average Asset Values	**31-Dec-10**			
Net Fixed Assets Smart Meters	$ 3,816,080			
Net Fixed Assets Tools and Equipment	$ 8,370			
Net Fixed Assets Computer Hardware	$ 5,907			
Net Fixed Assets Computer Software	$ 28,000			
Total Net Fixed Assets	$ 3,858,357	$ 3,858,357		
Working Capital				
Operation Expense	$ 91,642			
15 % Working Capital	$ 13,746	$ 13,746		
Smart Meters included in Rate Base		$ 3,872,103		
Return on Rate Base				
Third-party long-term debt	56.0%	$ 2,168,378		
Deemed long-term debt	0.0%	$ -		
Short-term debt	4.0%	$ 154,884		
Deemed Equity	40.0%	$ 1,548,841		
		$ 3,872,103		
Third-party long-term debt rate	5.56%	$ 120,562		
Deemed long-term debt rate	0.00%	$ -		
Short-term debt rate	1.33%	$ 2,060		
Return on Equity	8.01%	$ 124,062		
Return on Rate Base		$ 246,684	$	246,684
Operating Expenses				
Incremental Operating Expenses			$	91,642
Amortization Expenses				
Amortization Expenses - Smart Meters		$ 270,918		
Amortization Expenses - Tools and equirement		$ 930		
Amortization Expenses - Computer Hardware		$ 1,969		
Amortization Expenses - Computer Software		$ 7,000		
Total Amortization Expenses			$	280,817
Revenue Requirement Before PILs			$	619,143
Calculation of Taxable Income				
Incremental Operating Expenses			-$	91,642
Depreciation Expenses			-$	280,817
Interest Expense			-$	122,622
Taxable Income For PILs			$	124,062
Grossed up PILs			$	34,819
Revenue Requirement Before PILs			$	619,143
Grossed up PILs			$	34,819
Revenue Requirement for Smart Meters			**$**	**653,962**
Net Revenue Requirement for 2010			**$**	**653,962**
Average customer #				27,754
Rate Adder per month per metered customer				$1.96

PILs Calculation 2010

		31-Dec-10
INCOME TAX		
Net Income	$	124,062
Amortization	$	280,817
CCA - Class 47 (8%) Smart Meters	-$	314,389
CCA - Class 8 (20%) Tools and Equipment	-$	1,674
CCA - Class 50 (55%) Computers	-$	1,990
CCA - Class 12 (100%) Computers Software	-$	17,500
Change in taxable income	$	69,326
Tax Rate		31.00%
Income Taxes Payable	$	21,491
ONTARIO CAPITAL TAX		
Smart Meters	$	4,856,815
Tools and Equipment	$	8,835
Computer Hardware	$	6,892
Computer Software	$	24,500
Rate Base	$	4,897,042
Less: Exemption	$	-
Deemed Taxable Capital	$	4,897,042
Ontario Capital Tax Rate		0.075%
Net Amount (Taxable Capital x Rate)	$	3,673

Gross Up

	PILs Payable		Gross Up	Grossed Up PILs	
Change in Income Taxes Payable	$	21,491	31.00%	$	31,147
Change in OCT	$	3,673		$	3,673
PIL's	$	25,164		**$**	**34,819**

Smart Meter Average Net Fixed Assets 2010

Net Fixed Assets - Smart Meters	Prior to 31-Dec-08	31-Dec-09	31-Dec-10
Opening Capital Investment	$ -	$ 239,621	$ 2,887,571
Capital Investment Year 1	$ 239,621		
Capital Investment Year 2		$ 2,647,950	
Capital Investment Subsequent Years			$ 2,352,389
Closing Capital Investment	$ 239,621	$ 2,887,571	$ 5,239,960
Opening Accumulated Amortization	$ -	$ 7,987	$ 112,227
Amortization Year 1 (15 Years Straight Line)	$ 7,987	$ 15,975	$ 192,505
Amortization Subsequent Years		$ 88,265	$ 78,413
Closing Accumulated Amortization	$ 7,987	$ 112,227	$ 383,145
Opening Net Fixed Assets	$ -	$ 231,634	$ 2,775,344
Closing Net Fixed Assets	$ 231,634	$ 2,775,344	$ 4,856,815
Average Net Fixed Assets	$ 115,817	$ 1,503,489	$ 3,816,080

Net Fixed Assets - Tools and Equipment	Prior to 31-Dec-08	31-Dec-09	31-Dec-10
Opening Capital Investment	$ -	$ -	$ 9,300
Capital Investment Year 1	$ -		
Capital Investment Year 2		$ 9,300	$ -
Closing Capital Investment	$ -	$ 9,300	$ 9,300
Opening Accumulated Amortization	$ -	$ -	$ 465
Amortization Year 1 (10 Years Straight Line)	$ -	$ -	$ 930
Amortization Year 2 (10 Years Straight Line)		$ 465	$ -
Closing Accumulated Amortization	$ -	$ 465	$ 1,395
Opening Net Fixed Assets	$ -	$ -	$ 8,835
Closing Net Fixed Assets	$ -	$ 8,835	$ 7,905
Average Net Fixed Assets	$ -	$ 4,418	$ 8,370

Net Fixed Assets - Computer Hardware	Prior to 31-Dec-08	31-Dec-09	31-Dec-10
Opening Capital Investment	$ -	$ 9,845	$ 9,845
Capital Investment Year 1	$ 9,845		
Capital Investment Year 2		$ -	$ -
Closing Capital Investment	$ 9,845	$ 9,845	$ 9,845
Opening Accumulated Amortization	$ -	$ 985	$ 2,954
Amortization Year 1 (5 Years Straight Line)	$ 985	$ 1,969	$ 1,969
Amortization Year 2 (5 Years Straight Line)		$ -	$ -
Closing Accumulated Amortization	$ 985	$ 2,954	$ 4,923
Opening Net Fixed Assets	$ -	$ 8,861	$ 6,892
Closing Net Fixed Assets	$ 8,861	$ 6,892	$ 4,923
Average Net Fixed Assets	$ 4,430	$ 7,876	$ 5,907

Net Fixed Assets - Computer Software	Prior to 31-Dec-08	31-Dec-09	31-Dec-10
Opening Capital Investment	$ -	$ -	$ 35,000
Capital Investment Year 1	$ -		
Capital Investment Year 2		$ 35,000	$ -
Closing Capital Investment	$ -	$ 35,000	$ 35,000
Opening Accumulated Amortization	$ -	$ -	$ 3,500
Amortization Year 1 (5 Years Straight Line)	$ -	$ -	$ 7,000
Amortization Year 2 (5 Years Straight Line)		$ 3,500	$ -
Closing Accumulated Amortization	$ -	$ 3,500	$ 10,500
Opening Net Fixed Assets	$ -	$ -	$ 31,500
Closing Net Fixed Assets	$ -	$ 31,500	$ 24,500
Average Net Fixed Assets	$ -	$ 15,750	$ 28,000

Total Assets			
Total Fixed Assets	$ 249,466	$ 2,941,716	$ 5,294,105
Total Accumulated Amortization	$ 8,972	$ 119,146	$ 399,962
Closing Net Fixed Assets	$ 240,494	$ 2,822,570	$ 4,894,143

For PILs Calculation

UCC - Smart Meters
CCA Class 47 (8%)

	Prior to 31-Dec-08	31-Dec-09	31-Dec-10
Opening UCC	$ -	$ 230,036	$ 2,753,665
Capital Additions	$ 239,621	$ 2,647,950	$ 2,352,389
UCC Before Half Year Rule	$ 239,621	$ 2,877,986	$ 5,106,054
Half Year Rule (1/2 Additions - Disposals)	$ 119,811	$ 1,323,975	$ 1,176,195
Reduced UCC	$ 119,811	$ 1,554,011	$ 3,929,860
CCA Rate Class 47	8%	8%	8%
CCA	$ 9,585	$ 124,321	$ 314,389
Closing UCC	$ 230,036	$ 2,753,665	$ 4,791,665

UCC - Tools and Equipment
CCA Class 8 (20%)

	Prior to 31-Dec-08	31-Dec-09	31-Dec-10
Opening UCC	$ -	$ -	$ 8,370
Capital Additions	$ -	$ 9,300	$ -
UCC Before Half Year Rule	$ -	$ 9,300	$ 8,370
Half Year Rule (1/2 Additions - Disposals)	$ -	$ 4,650	$ -
Reduced UCC	$ -	$ 4,650	$ 8,370
CCA Rate Class 10	20%	20%	20%
CCA	$ -	$ 930	$ 1,674
Closing UCC	$ -	$ 8,370	$ 6,696

UCC - Computer Equipment
CCA Class 50 (55%)

	Prior to 31-Dec-08	31-Dec-09	31-Dec-10
Opening UCC	$ -	$ 8,040	$ 3,618
Capital Additions Hardware	$ 9,845	$ -	$ -
Capital Additions Software			
UCC Before Half Year Rule	$ 9,845	$ 8,040	$ 3,618
Half Year Rule (1/2 Additions - Disposals)	$ 4,923	$ -	$ -
Reduced UCC	$ 4,923	$ 8,040	$ 3,618
CCA Rate Class 50	55%	55%	55%
CCA	$ 1,805	$ 4,422	$ 1,990
Closing UCC	$ 8,040	$ 3,618	$ 1,628

UCC - Computer Software
CCA Class 12 (100%)

	Prior to 31-Dec-08	31-Dec-09	31-Dec-10
Opening UCC	$ -	$ -	$ 17,500
Capital Additions Hardware			
Capital Additions Software	$ -	$ 35,000	$ -
UCC Before Half Year Rule	$ -	$ 35,000	$ 17,500
Half Year Rule (1/2 Additions - Disposals)	$ -	$ 17,500	$ -
Reduced UCC	$ -	$ 17,500	$ 17,500
CCA Rate Class 12	100%	100%	100%
CCA	$ -	$ 17,500	$ 17,500
Closing UCC	$ -	$ 17,500	$ -

b) Please reconcile the annual capital spending profile for smart meters set out in Attachment 1, page 1 with that reported in Exhibit 9/Tab 3/Schedule 1, Attachment 1.

Response:

See response to a)