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February 4, 2009

Delivered by E-mail and Courier

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, Suite 2700
Toronto, Ontario
M4P 1E4

Dear Ms. Walli:

Re: OEB File Nos. EB-2008-0241, EB-2008-0242 and EB-2008-0243
Peterborough Distribution Inc. 2009 Electricity Distribution Rate Application

We are counsel to Peterborough Distribution Inc. ("PDI") in the above-captioned matter. Please find accompanying this letter two hard copies of PDI's responses to the interrogatories of Board Staff in this proceeding, together with a disk containing the responses and an electronic copy of Attachment F, the model requested in Board Staff question 41(c). The responses are being sent to intervenors of record by e-mail; due to the size of Attachment F, we will deliver to each of the intervenors a copy of the disk that accompanies these hard copies of the responses.

Should you have any questions or require further information, please do not hesitate to contact me.

Yours very truly,

BORDEN LADNER GERVAIS LLP

Original Signed James C. Sidlofsky

James C. Sidlofsky
JCS/dp

cc: Larry Doran, PDI
Rob Kent, PDI
Carol Anne Little, PDI
John Stephenson, PDI
Intervenors of Record

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EB-2008-0241
EB-2008-0242
EB-2008-0243

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

AND IN THE MATTER OF an Application by Peterborough Distribution Inc. for an Order or Orders approving and fixing just and reasonable distribution rates and other charges, effective May 1, 2009.

PETERBOROUGH DISTRIBUTION INC.

2009 ELECTRICITY DISTRIBUTION RATE APPLICATION

RESPONSES TO BOARD STAFF INTERROGATORIES

FILED: FEBRUARY 4, 2009

Applicant:
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EB-2008-0241
EB-2008-0242
EB-2008-0243

Peterborough Distribution Inc. ("PDI")
2009 Electricity Distribution Rate Application

PDI Responses to Board Staff Interrogatories

Filed: February 4, 2009

INDEX

EB-2008-0241
EB-2008-0242
EB-2008-0243

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

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

Peterborough Distribution Inc. ("PDI") Responses to OEB Staff Interrogatories

Filed : February 4, 2009

General – Economic Assumptions

1. Updates to evidence

a) Since the filing of the application, given the current economic situation, has Peterborough Distribution (PDI) assessed the situation and identified any specific issues that would have a material impact on its load and revenue forecasts and bad debt expense forecast?

Response:

While the general economic climate is deteriorating and the overall threat of commercial business closures is increasing, particularly in relation to the auto industry, PDI is not aware of any material specific issues affecting the Application at this time. In general terms, it is quite possible and expected that bad debts will increase in this climate. PDI can not provide any specific evidence at this time in response to this question.

b) If so, can PDI provide the necessary evidence and an estimate of the timing of any update including supporting facts and calculations?

Response:

PDI has no specific evidence at this time.

Exhibit 2 - Rate Base

2. Rate Base and Capital Expenditures – Ref: Exhibit 2

Please provide information for the period 2006 to 2009 in the following table format with respect to PDI's distribution operations:

Response:

The table has been completed as requested.

	2006 Actual	2007 Actual	2008 Bridge	2009 Test
Allowed Return on Equity (%) on the regulated rate base *	4.5%	4.5%	4.2%	3.7%
Actual Return on Equity (%) on the regulated rate base	4.1%	2.7%	2.5%	2.9%
Retained Earnings	5,065,006	4,908,754	4,545,929	4,252,537
Dividends paid to shareholders	2,376,023	1,576,088	1,702,788	1,856,729
Sustaining capital expenditures (excluding smart meters)	898,649	3,280,483	2,244,500	3,018,000
Development capital expenditures (excluding smart meters)	3,077,892	2,649,965	3,075,500	2,463,000
Operations capital expenditures	641,761	178,193	50,000	25,000
Smart Meters capital expenditures	256,537	411,821	361,879	5,000,000
Other capital expenditures (please specify)	0	0	0	0
Total capital expenditures (including smart meters)	4,874,839	6,520,462	5,731,879	10,506,000
Total capital expenditures (excluding smart meters)	4,618,302	6,108,641	5,370,000	5,506,000
Depreciation expense	2,900,527	3,149,121	3,199,320	3,540,000
Construction Work in Progress	2,818,766	2,098,787	2,400,000	2,400,000
Rate Base	51,792,292	53,291,656	53,571,505	54,126,094
Taxes/PILs paid/forecasted,	1,817,789	1,382,742	1,107,207	1,228,827
Number of Customer Additions (total)	335	451	367	373
- Residential	329	412	370	375
- General Service < 50 kW	8	37	7	(4)
- General Service > 50 kW, Intermediate and Large Use	(2)	2	(10)	2
Number of Customers (total, December 31)	33,700	34,151	34,518	34,891
- Residential	29,726	30,138	30,508	30,883
- General Service < 50 kW	3,598	3,635	3,642	3,638
- General Service > 50 kW, Intermediate and Large Use	376	378	368	370

** Allowable return on Equity (%) calculated as maximum allowable return on equity X deemed equity on regulated rate base %.*

3. Continuity Schedule – Ref: Exhibit 2 / Tab 2 / Schedule 1

In the tables for continuity of gross fixed assets, depreciation and net fixed assets in the referenced evidence, PDI shows no accumulated depreciation (credit) related to account 1995 – Contributions & Grants. Please explain in detail, with reasons, PDI's accounting treatment related to this account.

Response:

The accumulated depreciation (credit) relating to account 1995 has been included as a reduction in the accumulated amortization accounts associated with the OEB asset accounts, and not reported separately

Contributed capital has not been included in the rate base and therefore there is no return earned on contributed capital.

Management will be changing the process of recording the accumulated amortization going forward and will record the amounts in account 1955.

4. Continuity Schedule – Ref: Exhibit 2 / Tab 2 / Schedule 1

In the referenced evidence, PDI shows no disposals or adjustments to gross fixed assets in any of 2006 and 2007 actual, 2008 bridge and 2009 test years.

a) Please confirm that PDI had no, or does not plan to have in 2009, disposal or other adjustments to assets.

Response:

PDI has not had any disposals and does not plan to have any disposals or other adjustments to the assets in 2009.

PDI does not record the disposal of grouped assets as asset disposal within the various groups until the asset has been fully depreciated.

Assets that remain in service after reaching the end of their average useful life are not regarded as fully depreciated until actual retirement.

b) PDI experienced significant damage to its Peterborough service area distribution system due to storms in 2006, such that it applied for and was approved Z-factor treatment in its 2007 IRM distribution rate application. Please explain PDI's accounting treatment for distribution assets not fully depreciated but written off or disposed of as a result of the 2006 storms and subsequent storm recovery.

Response:

PDI did not record the disposal of the 2006 storm damaged assets as they were not fully depreciated and the associated replacement costs were expensed.

PDI utilizes a single asset or grouped asset approach. Under this methodology functionally interdependent assets or assets that by their nature make identification of individual components impractical are acquired or disposed of at the same time and are accounted for as one asset. As components are replaced they are expensed as repair and maintenance and the original capital investment remains unchanged.

5. Miscellaneous Equipment – Ref: Exhibit 2 / Tab 2 / Schedule 1

In the referenced evidence, PDI shows an opening balance in 2006 of $NIL, an addition to gross fixed assets of $82,385 and a depreciation expense of $16,477 in 2006. The continuity schedules show similar depreciation expenses in 2007 actual, 2008 bridge and 2009 test years, with no additions or disposals to gross fixed assets to this account. Board staff interpret this to mean that a full year's depreciation expense was applied for the $82,385 of assets added in 2006. The usual treatment is to apply the ½-year rule when assets are added to rate base.

a) Please confirm whether PDI applied a full-year depreciation expense related to this account in 2006. If so, please explain the reasons for so doing.

Response:

Yes, PDI applied a full year of depreciation expense to this account in 2006. PDI's accounting policy is to apply a full year of depreciation.

b) Please confirm whether PDI applies the ½-year rule for calculating the depreciation expense related to capital assets in the year of addition.

Response:

PDI does not use the ½ yr rule for accounting purposes.

c) If PDI does not apply the ½-year rule as described in b) above, please explain.

Response:

Although the ½ yr rule has not been applied for accounting purposes, it has been employed in determining rate base.

6. Work in Progress – Ref: Exhibit 2 / Tab 2 / Schedule 1

In the referenced evidence, for Work in Progress, PDI shows a 2006 opening balance of $1,684,823 and an addition of $1,133,943, with no disposals. For 2007, there is an opening balance of $2,816,766 with a “negative addition” of ($719,979) that year, leaving a 2007 year-end balance of $2,098,787. The balance is unchanged for the 2008 bridge and 2009 test years.

Board staff understand Work in Progress as relating to capital expenditures where the assets are not in-service (i.e. not “used and useful”) at the end of the calendar/fiscal year. It would be usual to expect additions and disposals to work in progress annually as assets are completed and put in progress while new projects carry over to the following year. Major projects, such as a major station build or rebuild, may carry-over more than one year, but most Work in Progress would be completed the following year.

a) Please provide a detailed explanation of the accounting treatment for Work in Progress, for all years, as shown in the continuity schedule.

Response:

Work in progress consists of the unfinished construction projects that are in the production process.

Additions to and transfers from the work in progress account have been netted off in the additions column.

The 2008 and 2009 estimated values are based upon the assumption that the dollar value of the 2008 and 2009 capital program will be placed into service through a combination of WIP transfers and completed capital activities within the year.

b) Please provide a description of all major projects covered by Work in Progress for each year’s balance and additions. Please indicate which projects are multi-year (more than one year in duration).

Response:

Detailed WIP summaries of major projects for 2006 and 2007 have been provided below. The 2008 and 2009 WIP forecast assumes no material change in the WIP balance. This assumes that the dollar value of the 2008 and 2009 capital program will be placed into service through a combination of WIP transfers and completed capital activities within the year.

	B	D	F	H	K
4	31-Dec-06	Balance	Adds	Balance	Description
5	Projects	Forward	2006	in	
6				WIP	
7					
10	**Subtransmission O/H:**				
11	4153-1-1119	50,855.39	70,625.92	121,481.31	Neal Drive, Pido Road etc
12	**Distribution U/G Lines:**				
13	4156-1-1123	392,599.08	53,033.56	445,632.64	Bramble, Eashill, Foxmeadow, Maria, Marsdale, Meadowview and Walker - civil portion
14	4156-1-1172		57,109.88	57,109.88	Middlefield Subdivision - conversion from 4kV to 27kV
15	4156-1-1234	6,052.27	503,134.27	509,186.54	Cumberland from Hilliard to Ungava 27.6kV extension from Hilliard to Ungava
16	4156-1-1237	0.00	32,899.64	32,899.64	Heritage Park Phase 2 - transformers and system connection
17	4156-1-1314		47,936.00	47,936.00	Hunter Street
18	4156-1-1315		30,830.21	30,830.21	Waverly Heights Phase 1 - transformer & system connection costs
19	4156-1-1336		100,014.46	100,014.46	Cherryhill, Applewood, Bankside, Moncrief, Redwood - U/G conversion 4.16kV to 27.6kV electric works
20	4156-1-1337		27,052.36	27,052.36	Cumberland U/G conversion 4.16kV to 27.6KV electric works
21	**Distribution O/H Lines:**				
22	4157-1-1125	81,659.39	13,597.72	95,257.11	Maria Street - electrical portion
23	4157-1-1151	87,786.16	302,897.88	390,684.04	Neal and Ashburnham Drive
24	4157-1-1168	319.33	154,864.67	155,184.00	Springbrook Dr, Daleview Ave O/H upgrade
25	4157-1-1227	4,131.68	194,692.66	198,824.34	Park Street new YMCA
26	4157-1-1367		38,218.92	38,218.92	Juliet
27	4157-3-1343		64,090.50	64,090.50	Monaghan and McDonnel St - relocate existing poles between McDonnel and Walnut
28	4157-3-1357		50,807.42	50,807.42	Ocarrol and Benson
29	**U/G Services:**				
30	4158-1-1124	61,224.37	85,083.91	146,308.28	Maria, Marsdale and Walker - electrical portion
31	4158-1-1300		43,551.65	43,551.65	1091 Chemong Road U/G primary service for renovated plaza
32	4158-1-1355		24,377.31	24,377.31	526 McDonnel St
33	4158-1-1369		56,051.21	56,051.21	Portage Place - chemong Road
35		**684,627.67**	**1,950,870.15**	**2,635,497.82**	

	B	D	F	H	J	K
4	31-Dec-07	Balance	Adds	Balance	Description	Multi Year
5	Projects	Forward	2007	in		
6				WIP		
7						
10	**Subtransmission O/H:**					
11	4153-1-1119	121,481.31	258,368.40	379,849.71	Neal Drive, Pido Road etc	Yes
12	**Substations:**					
13	4155-1-1470		63,084.70	63,084.70	SCADA ICCP implementation	
14	**Distribution U/G Lines:**					
15	4156-1-1315	30,830.21	3,048.35	33,878.56	Waverly Heights Phase 1 - transformer & system connection costs	Yes
16	4156-1-1372	4,784.32	658,094.32	662,878.64	Cherryhill Subdivision Phase 2 and various other locations to be named	Yes
17	4156-1-1401	0.00	47,596.62	47,596.62	Waverly Heights Phase 2 - transformer and system connection	
18	**Distribution O/H Lines:**					
19	4157-1-1396	431.13	94,877.23	95,308.36	Armour Road - Waverly Heights Subdivision	Yes
20	4157-1-1434		65,092.84	65,092.84	The Parkway and Harper Road - Visitor Center	
21	4157-1-1462		61,968.49	61,968.49	Romaine St - rebuilding O/H 4KV	
22	4157-1-1466		161,268.92	161,268.92	Brealey Drive and Kawartha Heights	
23	4157-1-1501		60,081.23	60,081.23	Erskine Ave/Roger Neilson School area	
24	4157-1-1539		30,744.29	30,744.29	Kingdon Blvd	
25	4157-3-1543		27,337.21	27,337.21	1251 Lansdowne St W	
26	**U/G Services:**					
27	4158-1-1492		42,611.15	42,611.15	Lansdowne St - u/g primary service to sewage pumping station required for Westview Village Phase 2	
28	4158-2-1460		64,353.60	64,353.60	Romaine St rebuilding UG services	
29	4158-2-1506		30,812.18	30,812.18	167, 169, 171 Hazlitt St	
30	**O/H Services:**					
31	4159-1-1335	218.53	30,059.26	30,277.79	Lansdowne Street cost of building O/H line to service Westview Village	Yes
32	4159-2-1515		23,546.29	23,546.29	300 Charlotte St	
34		**157,745.50**	**1,722,945.08**	**1,880,690.58**		

7. Meters – Ref: Exhibit 2 / Tab 2 / Schedules 1 and 3

In the referenced evidence, PDI shows the following as annual capital additions for meters.

		2006 actual	2007 actual	2008 bridge	2009 test
Meters - Account 1860	Additions	$ 646,439	$ 163,463	$ 125,000	$ 225,000

Exhibit 2 / Tab 2 / Schedule 3 explains that $498,098 of the 2006 meter capex was for wholesale meter points, per regulatory requirements, with $115,267 for new electric meters for customer connections. PDI provides no description of meter capex for 2007 actual and 2008 bridge years. With respect to 2009 test year, PDI indicates, on page 6 of Exhibit 2 / Tab 2 / Schedule 3, that $100,000 is for new General Service customers and $25,000 for wholesale metering. This leaves $100,000 in proposed 2009 metering capex unexplained.

a) Please provide descriptions of meter capital expenditures in 2007, 2008 and 2009 not already provided in evidence.

Response:

2007 - New General Service Meters: approximate value $127,000
- Residential Meters: approximate value $36,000.

2008 - General Service Meters: $100,000, M8 Wholesale Meter: $25,000 (did not proceed in 2008).

2009 - Additional $100,000 is for replacement of Bulk Primary Metering Units that are found to be PCB contaminated.

b) In its application, PDI is seeking an increased smart meter funding adder of $1.00 and indicates that it is authorized for smart meter deployment. PDI states that it is intending to begin deploying smart meters in 2009. What, if any, efforts will PDI take in 2009 or has taken in recent years to minimize the costs for replacing conventional meters unless necessary? Has PDI investigated or requested extensions for meters whose seals are about to expire until the meters are replaced?

Response:

In an effort to minimize the cost of replacing conventional meters and the value of the stranded asset, PDI has been installing smart meters in place of conventional meters for new or replacement meters since 2007. PDI experienced a failed sample group of several hundred meters in 2007 and these meters were replaced with smart meters. The replacement meters have been part of PDI’s CDM pilot test of smart metering and will remain in service as smart meters. The meters that were installed during the pilot program are from the same supplier and have essentially the same functionality as the meters being installed in PDI's mass smart meter installation.

Meter seal extensions for 2008 and 2009 meters that are due to expire are to be requested from Measurement Canada. The meters will be replaced with smart meters in 2009.

8. Asset Management – Ref: Exhibit 2 / Tab 3 / Schedule 4, Exhibit 2 / Tab 3 / Schedule 4 / Appendix A, Exhibit 2 / Tab 3 / Schedule 2, Exhibit 4 / Tabs 1 and 2

Asset management consists of processes and systems that help evaluate, prioritize, and select the distributor's maintenance and capital plans to maximize the benefits to its customers and shareholder.

For the purpose of providing the information regarding its maintenance and capital plans, PDI should use its identified materiality threshold items.

a) In regards to PDI's 2009 capital plans:
   i) Please provide a list of criteria and rationale that PDI has utilized in prioritization and selection of its 2009 capital projects.
   ii) Please complete the following table and provide ranking and the description of the identified material capital projects. Please note that the rating "1" is the highest priority, rating "2" is the second highest priority, rating "3" is the third highest priority etc. Please use additional rows, if necessary.
   iii) Please explain and file with the Board necessary evidence, if any, how the priorities of these capital projects are determined by PDI's management using the criteria identified in part "a(i)", e.g. asset condition study, system planning, regulatory compliance, etc.

Response:

i) The following criteria have been utilized by PDI in prioritization and selection of its 2009 capital projects (not in order of priority):

- Age and condition of asset.

Rationale: Older assets take priority for replacement to maintain system reliability, safety and efficiency.

- New Connection.

Rationale: New connections must be completed as a condition of service and a requirement of the distributor's licence.

- Public and Worker Safety.

Rationale: Among other regulatory requirements, licensed distributors are required to follow good utility practices in operating and maintaining their distribution system. The maintenance of public and worker safety are high priorities for PDI.

- System Reinforcement.

Rationale: New assets are added to address growth, improve operational efficiencies and maintain system performance expectations.

- Regulatory Requirement.

Rationale: New requirements must be met by law or condition of distributor's licence.

2009 Capital Projects

Priority Ranking	Project Name	Description of Project	Type of Program	Capital Investment ($)	Discretionary or Non-discretionary	Start Date of Project	Date in Service	Rationale for Priority Selection
1	TRPC Extension	44 kV Sub-transmission extension	New Asset	$350,000	Non-discretionary	January 2009	July 2009	Required to connect new RESOP Generator.
1	Cumberland Ave Rebuild	New U/G Feeder and Rebuild O/H Line	New Asset	$600,000	Non-discretionary	April 2009	July 2009	Extend 27.6 kV network to supply new subdivision and load relief for a 4.16 kV substation.
1	Subdivisions	New Subdivisions	New Asset	$300,000	Non-discretionary	2009	2009	Connections of new subdivisions.
1	Customer Service Connections	New or Upgraded Customer Connections	New Asset	$913,000	Non-discretionary	2009	2009	New Customer Connections.
2	Underground Line Rebuild	U/G Replacement Program	Replacement	$500,000	Discretionary	April 2009	November 2009	Selected projects by age and condition assessment.
2	Overhead Line Rebuild	O/H Replacement Program	Replacement	$1,075,000	Discretionary	May 2009	December 2009	Selected projects by age and condition assessment.
2	Market Plaza	Rebuild Customer Transformer Installation	Replacement	$100,000	Non-discretionary	June 2009	June 2009	Condition Assessment, Public Safety.
3	General Projects – Meters	General Service Customers	New Asset	$125,000	Non-discretionary	2009	2009	New customer connections.
3	General Projects – Meters	Replace Primary Metering Units	Replacement	$100,000	Non-discretionary	2009	2009	PCB Testing to identify contaminated units – Federal Regulation

Priority Ranking	Project Name	Description of Project	Type of Program	Capital Investment ($)	Discretionary or Non-discretionary	Start Date of Project	Date in Service	Rationale for Priority Selection
3	General Projects – Transformers	Replace defective and PCB Contaminated Transformers	Replacement	$330,500	Non-discretionary	2009	2009	Reactive replacements and proactive replacements for PCB's.
3	General Projects – Customer Demand Extensions	Line Extensions required for new customers.	New Asset	$125,000	Non-discretionary	2009	2009	Capital line extension work required to connect new customers.
3	General Projects – Customer Connections	Line Work for new customer connections	New Asset	$100,000	Non-discretionary	2009	2009	Specific line work to connect new customers.
4	Lansdowne W. Relocation	Relocation Existing Lines	Replacement	$300,000	Discretionary	N/A	N/A	Project Delayed by Municipality.
Total $ for Prioritized Programs				$3,350,880				
Total $ Prioritized Programs as a % of Overall Total 2009 CAPEX				61%				
Discretionary Programs as % of Total Prioritized Programs				56%				
Non-discretionary Programs as % of Total Prioritized Programs				44%				

Priority Ranking	Project Name	Description of Project	Type of Program	Capital Investment ($)	Discretionary or Non-discretionary	Start Date of Project	Date in Service	Rationale for Priority Selection
Replacement Programs as % of Total Prioritized Programs				83%				
Rehabilitation Programs as % of Total Prioritized Programs				0%				
Upgrade Programs as % of Total Prioritized Programs				0%				
New Additions as % of Total Prioritized Programs				64%				

Notes:

1. Type of program can be replacement, rehabilitation, or upgrade of an existing asset, or an addition of a new asset.
2. Non-discretionary – a “must do” project or related directly to the core infrastructure (e.g. Stations, feeders, etc.), or the need for which is determined beyond the control of the Applicant, e.g. regulatory or Government initiatives.
3. Discretionary – the need is determined at the discretion of the Applicant and the program can be deferred.
4. Some programs may have the same priority ranking

b) In regard to PDI's 2009 maintenance plans:
  i) Please provide a list of criteria and rationale that PDI has utilized in prioritization and selection of its 2009 maintenance projects.
  ii) Please complete the following table and provide ranking and the description of the identified material maintenance projects. Please note that the rating "1" is the highest priority, rating "2" is the second highest priority, rating "3" is the third highest priority etc. Please use additional rows, if necessary.
  iii) Please explain and file with the Board necessary evidence, if any, how the priorities of these maintenance projects are determined and their expenditures are justified by PDI's management using the criteria identified in part "b(i)", e.g. reliability statistics, customer complaints, cost information, etc.

Response:

i) The following criteria have been utilized by PDI in prioritization and selection of its 2009 maintenance projects (not in order of priority):

- Service Level to Customer.

Rationale: Meet the expectations of the Customer to maintain supply of electricity.

- Regulatory Requirement.

Rationale: Meet the expectations of governing agencies to address regulatory requirements.

- System Reliability.

Rationale: Meet the service expectations of the customer and service quality requirements.

- Public and Worker Safety.

Rationale: Among other regulatory requirements, licensed distributors are required to follow good utility practices in operating and maintaining their distribution system. The maintenance of public and worker safety are high priorities for PDI.

2009 Maintenance Programs or Projects

Priority Ranking	Name of Program or Project	Ongoing or One-time	Type of Program	Description of Project	Maintenance Expenditure ($)	Rationale for Priority Selection
1	Overhead Distribution Breakdown Maintenance	Ongoing	Reactive	Repairs to Overhead Distribution System	$262,209	Required to maintain service to Customers.
1	Underground Distribution Maintenance	Ongoing	Reactive	Repairs to Underground Distribution System	$101,564	Required to maintain service to Customers.
1	Overhead Residential Services	Ongoing	Reactive	Repairs to Overhead Residential Services	$85,317	Required to maintain service to Customers.
1	Underground Residential Services	Ongoing	Reactive	Repairs to Underground Residential Services	$81,271	Required to maintain service to Customers.
2	Tree trimming	Ongoing	Preventive	This project is to perform tree trimming based on a three-year cycle.	$198,736	To maintain system reliability at current levels. Reduce outages to customers and reduce maintenance costs.
3	Substation Equipment Maintenance	Ongoing	Preventive	Regular substation maintenance on five-year cycle.	$81,346	Maintain safety and reliability of substations
3	Substation Grounds and Building Maintenance	Ongoing	Preventive	Regular monthly and annual maintenance of grounds and buildings.	$86,595	Maintain security and safety of substation sites.
3	Meter Maintenance and Test	Ongoing	Predictive	To maintain and repair revenue and wholesale meters.	$110,727	To meet regulatory obligations.
3	Meter Changeouts	Ongoing	Predictive	To change and replace meter sample groups.	$75,308	To meet Measurement Canada regulatory obligations.

Priority Ranking	Name of Program or Project	Ongoing or One-time	Type of Program	Description of Project	Maintenance Expenditure ($)	Rationale for Priority Selection
3	Meter Records	Ongoing	Predictive	To maintain appropriate records for business and regulatory purposes.	$80,535	To meet regulatory obligations and business objectives.
3	PCB Testing of Distribution Transformers	Three-year program	Predictive	To identify PCB contaminated transformers for replacement.	$75,433	To meet new Federal PCB regulations. Mitigate environmental risks.
3	Asset Management	Ongoing	Predictive	To develop tools and gather asset and condition data.	$76,220	To develop asset management strategies to optimize capital and operating expenditures.
Total Prioritized Programs					$1,315,261	
Total Prioritized Programs % of Overall 2009 Maintenance Programs					56%	

Notes:

1. Type of program can be Reactive, Preventive, or Predictive.
2. The need for implementing reactive programs may not occur, but be budgeted based on utility's business practice and based on past experience related to equipment failure or defects.
3. Some programs may have the same priority ranking

9. Asset Management Report – Ref: Exhibit 2 / Tab 3 / Schedule 4 / Appendix A

In Table 3 on page 5 of the referenced evidence, PDI indicates a total replacement cost of $30,720,000 for 384 km of overhead distribution. In Table 8 on page 11, PDI documents total expenditures of $90,464,500 over a 50-year plan for 384.4 km of overhead. Differences for other asset categories are apparent comparing Table 3 to other tables within the Asset Management Plan.

Please explain the differences between the replacement costs shown in Table 3 and those shown elsewhere under the discussion for each major asset category.

Response:

The replacement cost figures in Table 3 and other tables in section 2.0 of the Asset Management Report are first cut, high-level estimates that were initially used for illustrative purposes and to provide an understanding of order of magnitude. Table 8 for overhead included poles, conductor and other pole line hardware.

Further investigation, study and data gathering were performed and used to refine the replacement cost estimates for the larger grouped assets and summarized in Table 13.

10. Asset Management Report – Ref: Exhibit 2 / Tab 3 / Schedule 4 / Appendix A

Table 13 on page 19 of the Asset Management Report appears to differ with tables elsewhere in the report. Board staff has prepared the following table based on selected information in tables of the Asset Management Report.

Annual Replacement Costs

Year	Poles		Stations / Breaker Stations		
	Table 4	Table 13	Table 6		Table 13
			Total cost over 5 years	Average annual cost	Annual Replacement Cost
2008	$ 151,200	$ 117,000	$ 5,049,048	$ 1,009,810	$ -
2013	$ 184,500	$ 156,600	$ 4,558,998	$ 911,800	$ 1,009,810
2018	$ 612,000	$ 254,700	$ 6,078,664	$ 1,215,733	$ 911,800
2023	$ 402,300	$ 357,300	$ 1,519,666	$ 303,933	$ 1,215,733
2028	$ 650,700	$ 603,000	$ 1,683,016	$ 336,603	$ 303,933
2033	$ 755,100	$ 620,100	$ 3,202,682	$ 640,536	$ 32,670
2038	$ 701,100	$ 569,700	$ 6,242,014	$ 1,248,403	$ 640,536
2043	$ 1,190,700	$ 991,800	$ -	$ -	$ 1,248,403
2048	$ 1,420,200	$ 1,309,500	$ -	$ -	$ -
2053	$ 1,373,400	$ 1,236,600	$ -	$ -	$ -
2058	$ 1,102,500	$ 1,046,700			$ -

a) Please describe which numbers and tables are a better indication of PDI's current expected capital plans to maintain and replace its existing distribution infrastructure (i.e. absent customer and load growth) under its Asset Management Plan.

Response:

Table 13 is the best indication as it is contains the most current data available and summarizes costs in the larger asset groups. The replacement cost estimates average the suggested expenditures in five-year increments based on the asset age data. The five-year averages are target values to be achieved over the next five-year planning period.

b) Please provide further discussion on how the Asset Management Report links to and supports the capital programs and proposed capital expenditures for which PDI is seeking approval for setting 2009 distribution rates.

Response:

As noted at Exhibit 2, Tab 3, Schedule 4, pages 2 & 3, the underground line rebuild projects cost of $500,000 in the 2009 Capital Budget approximates the suggested spending levels in the Asset Management Report. The overhead line rebuild projects of $1,075,000 and the overhead line relocation Lansdowne West project of $300,000 approximate the suggested spending levels in the Asset Management Report. Further work is required on the Asset Management data and expenditure estimates in other asset categories that will guide future capital forecasts for replacement of the existing assets.

11. Asset Management Report – Ref: Exhibit 2 / Tab 3 / Schedule 4 / Appendix A – Poles

On page 7 of the referenced evidence, PDI states:

> "In any event anticipating a maximum pole replacement scenario of 2% per year it is clear that our present rate of replacement (0.4%) as a response to accidents or condition assessment, is unsustainable and a ramping up of expenditures on pole replacements will be necessary over the medium term. Specifics of the replacement rate and associated annual costs will be established once the pole testing program is underway and assumptions can be confirmed or clarified by the data obtained."

a) Please provide the basis for PDI's current pole replacement rate of 0.4% per annum.

Response:

The 0.4% rate noted in the report was calculated based on dedicated pole replacement due to reactive or condition assessed pole replacement. It does not take into account the pole replacement that occurs as a result of overhead line rebuilds, relocations or expansions.

b) Please provide further information on the current status of the pole testing program, and on what PDI intends to do in 2009. Please indicate the forecasted 2009 costs for the pole testing program.

Response:

Pole testing was performed on approximately 850 poles in 2008. It is the intention of PDI to test approximately 1,000 poles per year at an estimated cost of $20,000.

12. Asset Management Report – Ref: Exhibit 2 / Tab 3 / Schedule 4 / Appendix A – Overhead Wires

In Table 3 on page 5 of the referenced evidence, PDI indicates a total replacement cost of $30,720,000 for 384 km of overhead distribution. In Table 8 on page 11, PDI documents total expenditures of $90,464,500 over a 50-year plan for 384.4 km of overhead. Differences for other asset categories are apparent comparing Table 3 to other tables within the Asset Management Report.

a) Please explain the differences between the replacement costs shown in Table 3 and those shown elsewhere under the discussion for each major asset category.

Response:

This question appears to be identical to Staff Question 9. Please see PDI's response to that question.

b) Please describe which numbers are a better indication of PDI's current expected capital plans to maintain and replace its existing distribution infrastructure (i.e. absent customer growth) under its Asset Management Plan.

Response:

This question appears to be almost identical to Staff Question 10(a). Please see PDI's response to that question.

13. Asset Management Report – Ref: Exhibit 2 / Tab 3 / Schedule 4 / Appendix A – Operations and Maintenance

On page 16 of the referenced evidence, PDI states:

> "In addition to the end of life replacement of the infrastructure that has been discussed thus far, maintenance and refurbishment play an important role in ensuring a safe and reliable electrical delivery system. A well planned and specific maintenance program can extend the usable life of some components of the system. Expenditures on maintenance can be viewed several ways, first are the proposed maintenance activities devised and organized in a fashion which allows management to measure their effectiveness and report on their impact on reliability and safety? Second, is the utility spending optimized in terms of the life of the asset, would spending more money on items extend their life, or would less money spent have the same impact? At this point in time the utility has no reliable measurement tools that can answer these two questions effectively. Part of the ongoing asset management strategy will attempt to better address these issues."

a) Please indicate PDI's efforts to date, and its plans for 2009, to address how it can better understand when, how and how much should be spent on maintenance to extend the life of assets as opposed to when it becomes more cost effective and enhances reliability performance by replacing assets?

Response:

PDI is currently reviewing its current preventative maintenance programs to determine their effectiveness and efficiency. Part of the process is to determine the unit costs and study the expected results. Further study and review of the root causes of outages and reliability performance is expected to guide future strategies for the Asset Management Plan.

b) Please indicate the 2009 and ongoing operating expenditures PDI expects to spend to address the above issue.

Response:

PDI has identified internal staff resources in its Operations group to review the current programs, and to recommend and cost new ones. The budgeted amount is $73,000 per annum.

14. Working Capital Allowance – Ref: Exhibit 2 / Tab 1 / Schedule 1 and Exhibit 2 / Tab 4 / Schedule 1

For the 2009 test year, PDI shows an Administration & General Expenses forecast of $1,378,334 in Table 2 of Exhibit 2 / Tab 1 / Schedule 1 of the referenced evidence and $1,328,334 in the detailed calculation of the working capital allowance in Table 1 of Exhibit 2 / Tab 4 / Schedule 1. The difference seems to relate to the estimate for Account 5630 – Outside Services Employed, which is estimated as $210,021 for 2009 test year in the latter table, but is shown as $260,021 in the pro forma 2009 financial statements in Exhibit 1 / Tab 2 / Schedule 3 / Appendix B.

Please confirm the forecasted 2009 expenses for account 5630 and the working capital base and working capital allowance for which PDI is seeking approval in this application.

Response:

The amount for account 5630 – Outside Services Employed – should be $260,021, resulting in Administration and General Expenses of $1,378,334. PDI confirms that the working capital base for 2009 is $62,938,264 and the working capital allowance is $9,440,740

15. Depreciation Expense – Ref: Exhibit 4 / Tab 2 / Schedule 7 and Exhibit 2 / Tab 2 / Schedule 1

PDI provides only a summary description of depreciation expense treatment in Exhibit 4 / Tab 2 / Schedule 7, and refers to the spreadsheets in the Continuity Schedules of Exhibit 2 / Tab 2 / Schedule 1. The Continuity Schedule provides depreciation expense numbers by account, but does not provide information on the derivation of annual depreciation expense.

a) For each account listed in Exhibit 2 / Tab 2 / Schedule 1, please indicate the amortization/depreciation rate and the expected useful life for amortization/ depreciation purposes.

Response:

OEB Acct-#	Description	Depreciation Rate	Useful Life
1805	Land-Substations	0%	
1808	Buildings-Substations	Declining years	40 years
1820	Substations Equipment	Declining years	35 years
1830	Poles, Towers & Fixtures	4% Straight Line	25 years
1835	OH Conductor & Devices	4% Straight Line	25 years
1840	UG Conduit	4% Straight Line	25 years
1845	UG Conductors & Devices	4% Straight Line	25 years
1850	Line Transformers	4% Straight Line	25 years
1855	Services (OH & UG)	4% Straight Line	25 years
1860	Meters	4% Straight Line	25 years
1925	Computer-Software	20% Straight Line	5 years
1970	Load Management Controls	10% Straight Line	10 years

b) Please confirm that PDI complies with the Board's guideline amortization rates as documented in Appendix B of the *2006 Electricity Distribution Rate Handbook*. Where PDI deviates from the amortization rate documented therein, please provide an explanation for PDI's adopted amortization rate for each such account.

Response:

PDI is in compliance with the rates as documented in the 2006 Electricity Distribution Rate Handbook.

16. Smart Meters – Ref: Exhibit 9 / Tab 1 / Schedule 1

On pages 8-9 of Exhibit 9 / Tab 1 / Schedule 1, PDI states that it is requesting an increased smart meter rate adder of $1.00. It states that it is authorized to deploy smart meters pursuant to O.Reg. 427/06 and that it intends to do so in mid- to late-2009 assuming completion of contract negotiations with the selected vendor. PDI states that it expects to incur capital expenses around $5.6 million.

On October 22, 2008, the Board issued Guideline G-2008-0002 on "Smart Meter Funding and Cost Recovery". Section1.4 of the Guideline specifies filing requirements for distributors when seeking a smart meter funding adder greater than $0.30 per month per residential customer. Any such distributor must be authorized in accordance with the applicable regulations, and must have a clear intention on installing smart meters in the rate test year.

a) Please provide documentation supporting that PDI is becoming authorized to deploy smart meters pursuant to O.Reg. 427/06 as amended on June 25, 2008 by O.Reg. 235/08.

Response:

O.Reg. 235/08 Section 2, Paragraph (4) amended O.Reg. 427/06 by authorizing as discretionary metering activities for the purposes of section 53.18 of the *Electricity Act, 1998*, as amended, "Metering activities conducted by a distributor that has procured its smart meters pursuant to and in compliance with the parameters and process established by the Request for Proposal for Advanced Metering Infrastructure (AMI) – Phase 1 Smartmeter Deployment dated August 14, 2007, together with any amendments to it, issued by London Hydro Inc. (see paragraph 1(1)8 of O.Reg. 427/06, as amended). Accompanying this response are copies of O. Reg.235/08 and a letter from the Fairness Commissioner confirming the two highest ranked proponents for PDI's requirements from the London Hydro RFP.

ONTARIO REGULATION 235/08

made under the

ELECTRICITY ACT, 1998

Made: June 17, 2008
Filed: June 25, 2008
Published on e-Laws: June 26, 2008
Printed in *The Ontario Gazette*: July 12, 2008

Amending O. Reg. 427/06

(Smart Meters: Discretionary Metering Activity and Procurement Principles)

Note: Ontario Regulation 427/06 has previously been amended. Those amendments are listed in the Table of Current Consolidated Regulations – Legislative History Overview which can be found at www.e-Laws.gov.on.ca.

1. Ontario Regulation 427/06 is amended by adding the following section:

Definition

0.1 In this Regulation,

"smart meters" includes smart meters, metering equipment, systems and technology and any associated equipment, systems and technologies.

2. (1) Subsection 1 (1) of the Regulation is amended by adding the following paragraph:

3.1 Metering activities conducted by a distributor listed in paragraph 3, if the smart meters were procured subsequent to the process referred to in paragraph 3.

(2) Paragraph 4 of subsection 1 (1) of the Regulation is amended by striking out "meters, metering equipment, systems and technology and any associated equipment, systems and technologies" and substituting "smart meters".

(3) Paragraph 6 of subsection 1 (1) of the Regulation is amended by striking out "meters, metering equipment, systems and technology and any associated equipment, systems and technologies" and substituting "smart meters".

(4) Subsection 1 (1) of the Regulation is amended by adding the following paragraph:

8. Metering activities conducted by a distributor that has procured its smart meters pursuant to and in compliance with the parameters and process established by the Request for Proposal for Advanced Metering Infrastructure (AMI) – Phase 1 Smartmeter Deployment dated August 14, 2007, together with any amendments to it, issued by London Hydro Inc.

(5) Subsection 1 (2) of the Regulation is amended by striking out "meters, metering equipment, systems and technology and any associated equipment, systems and technologies" and substituting "smart meters".

(6) Subsection 1 (2.1) of the Regulation is amended by striking out "meters, metering equipment, systems and technology and any associated equipment, systems and technologies" and substituting "smart meters".

3. (1) Clause 2 (1) (b) of the Regulation is revoked and the following substituted:

(b) that any agreement entered into as a result of the procurement is economically prudent and cost effective, taking into consideration, but not limited to,

(i) all costs associated with the agreement, and

(ii) the costs of the agreement relative to any prior agreement entered into by the distributor for comparable acquisitions.

(2) Subsection 2 (3) of the Regulation is amended by striking out "metering equipment, systems and technology and any associated equipment, systems and technologies".

(3) Clause 2 (4) (a) of the Regulation is amended by striking out "metering equipment, systems and technology and any associated equipment, systems and technologies".

4. This Regulation comes into force on the day it is filed.

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PRP International, Inc.

Fairness Advisory Services

May 30, 2008

Mr. Larry Doran
President and CEO
Peterborough Distribution Inc.
1867 Ashburnham Drive, P.O. Box 4125 Station Main
Peterborough, ON K9J 6Z5

Dear Mr. Doran:

Subject: Attestation of the Fairness Commissioner
Advanced Metering Infrastructure RFP, August 2007
London Hydro & Consortium of LDCs Smartmetering Project

PRP International, Inc. is pleased to submit its letter report of the Fairness Commissioner for the noted Request for Proposal (RFP) evaluation and selection phase. This judgment is being provided for the information and use of each Consortium LDC Sponsor, in their consideration of the report from the Evaluation Phase, for this competitive transaction.

"It is the judgment of PRP International, Inc., as the Fairness Commissioner, that the determinations of the two (2) highest ranked Proponents for the Peterborough Distribution Inc. requirements are:

- *Elster Metering, as the recommended Preferred Proponent, based on its highest ranking, and*
- *KTI/ Sensus Limited being the second ranked Proponent.*

These determinations were made in a fair (objective and competent) manner and consistent with the evaluation and selection processes set out in the RFP, issued August 14, 2007."

A detailed report for your records will be submitted to you, by August 31, 2008. Should you have any questions or require clarification of any matter contained in this letter report, please contact the undersigned.

Yours truly,

Peter Sorensen
President
cc: Mr. Gary Rains, RFP Project Director

203 - 8 QUEEN STREET, SUMMERSIDE, PEI C1N 0A6
TELEPHONE: 902.436.3930 FAX: 604-677-5409
EMAIL: fairness@telus.net

b) Please provide the following information in accordance with section 4 of the Guideline:

i) the estimated number of smart meters to be installed in the rate test year;

Response:

30,000

ii) the estimated costs per installed meter, and in total;

Response:

$172 per meter, $5,787,868 in total.

iii) a statement as to whether PDI has purchased or expects to purchase smart meters or advanced metering infrastructure whose functionality exceeds the minimum functionality adopted in O.Reg. 425/06, and an estimate of the costs for "beyond minimum functionality" equipment and capabilities; and,

Response:

Remote controlled disconnects are being considered at an estimated cost of $100,000. This cost has not been included in the total estimated smart costs or the 2009 capital budget.

iv) a statement as to whether PDI has incurred, or expects to incur, costs associated with functions for which the Smart Metering Entity has the exclusive authority to carry out pursuant to O.Reg. 393/07, and an estimate of those costs.

Response:

PDI has not incurred, and does not expect to incur, costs associated with functions for which the Smart Metering Entity has the exclusive authority to carry out pursuant to O.Reg. 393/07.

Exhibit 3 - Operating Revenue

17. Distribution Revenue – Ref: Exhibit 3 / Tab 1 / Schedule 2; Exhibit 3 / Tab 2 / Schedule 8; Exhibit 9 / Tab 1 / Schedule 8

In Exhibit 3 / Tab 1 / Schedule 2 / page 1, PDI shows the 2009 "Distribution Revenues – Sub-Total" to be $13,627,922. In Exhibit 3 / Tab 2 / Schedule 8 / page 2, PDI shows the 2009 "Distribution Revenues $" to be $13,650,410. In Exhibit 9 / Tab 1 / Schedule 8 / page 1, it shows the 2009 "Total Distribution Revenue" to be $14,627,850.

a) Using the Exhibit 9 / Tab 1 / Schedule 8 / page 1, value of $14,627,850 as the reference point, please explain what each of the other values represent and reconcile the differences among the various values, and

Response:

The 2009 Distribution Revenue amounts, $13,627,922 and $13,650,410, are based upon the 2009 fiscal year. The $13,627,922 is the correct amount. The $13,650,410 was entered in error.

The $14,627,850 amount includes Low Voltage charges and is based upon the 2009 rate year.

b) Please show the calculations that arrive at the $13,627,922 and the $13,650,410 values.

Response:

The correct amount is the $13,627,922. This represents the 2009 fiscal year revenue budget and as such revenues are prorated between 2008 and 2009 rate years, 1/3 for 2008 and 2/3 for 2009.

		Revenue 2008 rate application		**Revenue 2009 rate application**	**SSS**	**Total**
2009 Fiscal Year		12,350,793		14,134,398	**Admin Fee**	2009
Distribution Revenues		33.33%		66.67%		Revenue
Residential	61.10%	2,515,050	58.39%	5,502,514	88,000	8,105,564
GS<50	16.77%	690,333	16.85%	1,587,466	0	2,277,799
GS>50	20.21%	831,902	19.69%	1,855,298	0	2,687,200
Large User	0.78%	31,971	1.07%	100,614	0	132,585
Unmetered Scattered Load	0.00%	0	1.26%	118,980	0	118,980
Street Light	1.00%	41,167	2.49%	234,596	0	275,763
Sentinel Lighting	0.15%	6,096	0.25%	23,935	0	30,031
	100.00%	**4,116,519**	**100.00%**	**9,423,403**	**88,000**	**13,627,922**

18. Weather Normalization and Modelling – Ref: Exhibit 3 / Tab 2 / Schedule 2

On page 1 of the referenced evidence, PDI indicates that the weather normalization that was generated was performed by Hydro One.

Please provide the Hydro One report and any spreadsheets received from Hydro One containing data supporting the calculation of the normalized historical load. (Any *summary reports* that PDI received from Hydro One that show the weather correction factors by class (as distinct from raw unprocessed data) are particularly requested.)

Response:

A copy of the Hydro One report accompanies these responses as Attachment “A”.

19. Weather Normalization and Modelling – Ref: Exhibit 3 / Tab 2 / Schedule 2

In pages 1 to 3 of the referenced evidence, PDI explains how it developed its 2009 load forecast for the weather-sensitive classes. While some details are missing, the essential approach used appears to be that PDI:

- o determined the 2009 forecasted customer count for each customer class,
- o determined the weather-normalized retail energy for each customer class for 2004,
- o determined the 2004 retail normalized average use per customer ("retail NAC") for each class by dividing each of the weather-normalized retail energy values by the corresponding number of customers/connections in each class existing in 2004,
- o applied the 2004 retail NAC for each class to the 2009 Test Year *without modification*, and
- o determined the 2009 Test Year energy forecast for each customer class by multiplying the applicable 2004 retail NAC value for each class by the 2009 forecasted customer count in that class.

a) Please confirm that the above is the essence of PDI's load forecasting methodology,

Response:

Confirmed

b) Please differentiate the approach used for weather sensitive loads from that used for non-weather sensitive loads, and

Response:

For the non-weather sensitive loads the approach used was that PDI:

- o determined the 2009 forecasted customer/connection count for each customer class,
- o determined the historical average retail energy use per customer/connection for each rate class from 2002 to 2007, and
- o applied the historical average use per customer/connection by the 2009 forecasted customer/connection count to determine the 2009 Test Year energy for each rate class.

c) Please fully correct any errors in the above explanation.

Response:

There are no errors to correct.

20. Expected Future Changes – Ref: Exhibit 3 / Tab 2 / Schedule 2 and Exhibit 3 / Tab 2 / Schedule 4

In Exhibit 3 / Tab 2 / Schedule 2 / page 1, PDI states: “The 2008 and 2009 customer numbers are forecast based on the average compounding growth rate for the period from 2002 to 2007.” and, on pages 1 and 2, PDI appears to have assumed that the consumption per customer by customer class remains constant from 2004 to 2009. In Exhibit 3 / Tab 2 / Schedule 4 / page 2, PDI notes the expected reclassification of eleven GS>50kW class customers to the GS<50kW class.

a) Please explain how PDI’s forecasting methodology is differentiated from an approach that would rely solely (or substantially when considering the inclusion of the expected reclassification) on the simple extrapolation of the past and which would ignore both broader economic effects that would impact the Province as a whole and energy consumption changes as a result of CDM, and

Response:

PDI understands that the load forecasting method used in the application is simplified and does not necessarily take into consideration factors that are included in more sophisticated methods. However, PDI also understands that the load forecasting methodology was used in many 2008 rate applications and was accepted by the Board. In particular in the Brantford Power Inc. Decision (EB-2007-0698) the Board Findings with regards to load forecasting stated:

> *"The Board accepts the Company’s customer forecast. The Board also accepts the Company’s use of 2004 weather normalized data. The Board has noted Board staff’s concerns, but the process to obtain this data was an intensive effort for all parties involved and the proposal is leveraging the value of this work. The Company has not expressed concern that its load may be overestimated."*

In order to prepare the load forecast PDI decided to use a method already approved by the Board to leverage on work completed for the cost allocation study and reduce the time needed to explain the forecast methodology. As a result, the PDI load forecast does not take into consideration the broader economic effects that would affect the Province as a whole and energy consumption changes as a result of CDM. In any event, it is unclear to PDI how to account for the economic conditions of the Province for energy consumption in the PDI service area. It is also PDI's understanding that the method to account for CDM was debated in the Toronto Hydro 2008, 2009 and 2010 rate applications (EB-2007-0680) and continues to be debated in other 2009 rate applications. It is PDI’s understanding that parties do not agree on how CDM adjustments should be made.

b) Please compare the economic assumptions made in the application with economic forecasts prepared by national economic forecasting institutions (e.g. Canadian chartered banks) and regional forecasters (e.g. Boards of Trade or regional councils).

Response:

Please see PDI's response to Question 20(a), above.

21. kW and Revenue Forecast – Ref: Exhibit 3 / Tab 2 / Schedule 2

On page 2 of the referenced evidence, PDI provides a table titled "…Wholesale kWh … and Retail NAC".

a) Please explain the process PDI used to convert from wholesale kWh to retail kWh,

Response:

The chart heading should read Retail kWh and not Wholesale – this was a typographical error. During the preparation of the cost allocation study, PDI provided rate class information to Hydro One at the wholesale level in order for Hydro One to prepare wholesale 2004 weather normalized data needed in the cost allocation study. The wholesale level rate class data was determined by applying an adjustment factor to the actual 2004 billed retail rate class data. Hydro One also required that the total of wholesale level rate class information was equal to total energy purchased by PDI in 2004. As a result, the adjustment factor reflected losses, adjustments for unbilled revenue and other adjustments to ensure the rate class wholesale amounts totalled the wholesale purchases.

The adjustment factor used to convert rate class billing data to wholesale amounts was used in this Application to convert from wholesale kWh to retail kWh.

b) Please describe any loss factor assumptions made, and

Response:

The approved loss factor at the time the cost allocation model was completed was used in determining the adjustment factor.

c) Please document the establishment of the loss factor value(s) used.

Response:

The establishment of the loss factor is outlined in the response to (b), above. However, to assist the Board, the following outlines the adjustment factor referenced in (a) and used to convert wholesale kWh to retail kWh for those classes that are weather sensitive.

Class	Wholesale kWh (2004)	Retail kWh (2004)	Adjustment Factor
Residential	303,198,498	285,057,855	1.064
GS <50 kW	130,264,748	121,526,407	1.072
GS >50 kW	329,469,749	309,414,899	1.065

22. kW and Revenue Forecast – Ref: Exhibit 3 / Tab 2 / Schedule 2 / page 2

On page 2 of the referenced evidence, PDI notes: "Specific classes are billed on demand charges…and require an estimate of billed kW. Billed kW is estimated based on using a ratio of historical billed kW to historical kWh, by class."

Please provide:

a) a detailed description of the process used to develop the class kWh to kW conversion factors, and

Response:

As shown in response to (b), below, the conversion factor used to convert kWh to kW is the weighted average ratio of kW to kWh from 2002 to 2007 by rate class for those rate classes that charge volumetric distribution charges on a kW basis.

b) the supporting values and the calculations to determine the class kWh to kW conversion factors.

Response:

The following table provides the supporting values and the calculations used to determine the class kWh to kW conversion factors.

Class	2002	2003	2004	2005	2006	2007	Total
GS >50 kW							
- kWh	313,285,232	321,263,084	309,414,899	323,322,965	321,823,307	334,460,762	1,923,570,249
- kW	769,795	772,437	786,950	764,986	805,377	830,730	4,730,275
2002 to 2007 Weighted Average kW/kWh factor							**0.002459**
Large Use							
- kWh	58,804,718	65,357,746	64,756,589	66,651,689	63,402,525	63,221,100	382,194,367
- kW	104,791	134,739	133,227	136,079	133,042	128,682	770,560
2002 to 2007 Weighted Average kW/kWh factor							**0.002016**
Sentinel Lighting							
- kWh	693,470	1,025,125	1,010,677	966,991	1,091,658	1,308,319	6,096,240
- kW	3,168	2,848	2,629	2,721	2,662	2,574	16,602
2002 to 2007 Weighted Average kW/kWh factor							**0.002723**
Street Lighting							
- kWh	4,679,216	6,292,294	5,980,324	5,985,582	6,283,519	6,588,942	35,809,877
- kW	16,434	17,707	16,548	16,365	16,568	16,613	100,235
2002 to 2007 Weighted Average kW/kWh factor							**0.002799**

23. Customer Count, kWh load, kW load and Revenue – Ref: Exhibit 3 / Tab 2 / Schedule 2

On page 1 of the referenced evidence, PDI provides the 2002 to 2007 historical customer and connections data by class. On page 2, it provides the 2004 weather normalized load for three specific classes. On page 3, it provides historical data for 2006 and 2007. With this minimal amount of basic data for the 2002 to 2007 period, an independent assessment of PDI's calculations is not possible.

On pages 1 and 2, PDI explains how it determined the 2004 retail normalized average use per customer ("retail NAC") for certain classes and apparently used this particular value for other years also. This does not appear to adequately weather-normalize the energy usage in historical years and does not allow for the possible change in energy usage per customer over the 2002 – 2009 period due, for example, to Conservation and Demand Management. The minimal amount of weather normalization and the constant retail energy assumption could potentially lead to forecasting errors.

a) Please file a data table for the historical years 2002 to 2007 that shows:
   i. the actual retail energy (kWh) for each customer class in each year,

Response:

Actual Retail Energy

The actual retail energy (kWh) for each rate class from 2002 to 2007 is provided in the following table

Class	2002	2003	2004	2005	2006	2007
Residential	301,118,299	287,513,562	285,057,855	297,081,386	290,645,501	286,683,602
GS <50 kW	123,019,891	122,055,150	121,526,407	126,518,339	124,767,156	125,727,009
GS >50 kW	313,285,232	321,263,084	309,414,899	323,322,965	321,823,307	334,460,762
Large Use	58,804,718	65,357,746	64,756,589	66,651,689	63,402,525	63,221,100
Sentinel Lights	693,470	1,025,125	1,010,677	966,991	1,091,658	1,308,319
Street Lighting	4,679,216	6,292,294	5,980,324	5,985,582	6,283,519	6,588,942
USL	1,310,816	2,489,202	2,444,704	2,325,282	2,174,601	2,211,753
Total	802,911,642	805,996,163	790,191,455	822,852,234	810,188,267	820,201,487

   ii. the *weather normalized* retail energy (kWh) for each customer class in each year (where, for the customer classes that PDI has identified as weather sensitive, the weather normalization process should, as a minimum, involve the direct conversion of the actual load to the weather normalized load using a multiplier factor for that year *and not rely on results for any other year*),

Response:

The following table outlines the weather normalized retail energy (kWh) for 2002 to 2007 for those classes that have been classified as weather sensitive (i.e. Residential, GS < 50 kW and GS > 50 kW).

Class	2002	2003	2004	2005	2006	2007
Residential	294,082,379	285,555,225	285,434,811	292,790,481	292,881,481	285,180,069
GS <50 kW	120,145,412	121,223,798	121,687,112	124,690,967	125,727,009	125,067,624
GS >50 kW	305,965,020	319,074,870	309,824,065	318,653,039	324,299,142	332,706,658

iii. the values of the weather correction factors used,

Response:

The values of the weather correction factors used are shown below:

2002	2003	2004	2005	2006	2007
97.66%	99.32%	100.13%	98.56%	100.77%	99.48%

iv. the customer count for each class in each year,

Response:

Customer Count:

Class / Year	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**
Residential – Weather sensitive	28,354	28,820	29,237	29,397	29,726	30,138
GS < 50 kW - Weather sensitive	3,656	3,637	3,649	3,590	3,598	3,635
GS > 50 kW – Weather sensitive	369	376	384	376	374	376
Large User	2	2	2	2	2	2
Sentinel Lighting - connections	667	702	660	689	682	464
Street Lighting - connections	7,808	8,046	8,078	8,275	8,238	8,324
Unmetered Scattered Load	12	12	10	10	10	10

v. the retail normalized average use per customer for each class in *each year* based on the *weather corrected* kWh data in item ii. above, and

Response:

The retail normalized average annual use per customer for the weather sensitive classes in provided in the following table:

Class	2002	2003	2004	2005	2006	2007
Residential	10,372	9,908	9,763	9,960	9,853	9,462
GS <50 kW	32,863	33,331	33,348	34,733	34,944	34,406
GS >50 kW	829,173	848,603	806,834	847,481	867,110	884,858

vi. as a footnote to the table, the source(s) of the weather correction factors.

Response:

The weather correction factors shown in iii above came from the IESO website, in the spreadsheet available at the following address:

http://www.ieso.ca/imoweb/pubs/marketReports/18Month_ODF_2008mar.xls.

The worksheet labelled Table 2.2 (Actual and Weather Corrected Weekly Energy Demand) from the IESO spreadsheet, a copy of which accompanies these responses as Attachment "B", was modified from the original format so that individual years' information could be added to determine the correction factor.

b) Please file a data table for the 2002 to 2009 period:

i. utilizing the retail normalized average use per customer values for each class in each year obtained in a) v. above for the historical years 2002 to 2007,

ii. including 2008 and 2009 projections for the customer count and the retail normalized average use per customer values (where these future values are based on economic or other relevant trends or, as a minimum, trends in the data) for each class, and

iii. as a footnote to the table, for each of the classes describe in detail the projection logic employed in ii. above.

Response:

The requested information is provided in the table below:

	2002	2003	2004	2005	2006	2007	2008	2009
Retail normalized average use per customer								
Residential	10,372	9,908	9,763	9,960	9,853	9,462	9,886	9,886
GS <50 kW	32,863	33,331	33,348	34,733	34,944	34,406	33,937	33,937
GS >50 kW	829,173	848,603	806,834	847,481	867,110	884,858	847,343	847,343
Customer count								
Residential	28,354	28,820	29,237	29,397	29,726	30,138	30,508	30,883
GS <50 kW	3,656	3,637	3,649	3,590	3,598	3,635	3,642	3,638
GS >50 kW	369	376	384	376	374	376	366	368
kWh = retail normalized average use per customer X customer count								
Residential	294,082,379	285,555,225	285,434,811	292,790,481	292,881,481	285,180,069	301,612,208	305,315,557
GS <50 kW	120,145,412	121,223,798	121,687,112	124,690,967	125,727,009	125,067,624	123,593,627	123,451,316
GS >50 kW	305,965,020	319,074,870	309,824,065	318,653,039	324,299,142	332,706,658	310,480,032	311,649,167

The method used to determine the retail normalized average annual use per customer values for 2008 and 2009 reflects the average for the years 2002 to 2007. The average was chosen as there did not appear to be a good trend line in the numbers.

The customer count numbers for 2008 and 2009 are equivalent to the customer numbers used in the Application and reflect the compounding growth rate in customer numbers from 2002 to 2007

c) Please file an updated version of the historical/forecast table filed in Exhibit 3 / Tab 2 / Schedule 2 / page 3, utilizing the *weather corrected* data determined in b) above.

Response:

An updated version of the historical/forecast table filed in Exhibit 3 / Tab 2 / Schedule 2 / page 3, utilizing the weather corrected data determined in b) above is shown in the following table.

PDI		Historical Board Approved From 2006 EDR	Historical Actual	Historical Actual Normalized	Historical Actual	Historical Actual Normalized	Bridge Year - Est.	Bridge Year Estimate Normalized	Test Year Normalized Forecast
Year		**2006**	**2006**	**2006**	**2007**	**2007**	**2008**	**2008**	**2009**
Residential	#	29,237	29,726	29,726	30,138	30,138	30,508	30,508	30,883
	kWh	295,729,054	290,645,501	292,881,481	286,683,602	285,180,069	290,203,651	301,612,208	305,315,557
GS < 50 kW	#	3,655	3,598	3,598	3,635	3,635	3,642	3,642	3,638
	kWh	123,850,266	124,767,156	125,727,009	125,727,009	125,067,624	125,962,708	123,593,627	123,451,316
GS >50	#	388	374	374	376	376	366	366	368
	kWh	322,910,204	321,823,307	324,299,142	334,460,762	332,706,658	325,935,442	310,480,032	311,649,167
	kW	791,840	805,377	797,488	830,730	818,163	801,512	763,505	766,380
Large Use	#	2	2	2	2	2	2	2	2
	kWh	62,973,018	63,402,525	63,402,525	63,221,100	63,221,100	63,221,100	63,699,061	63,699,061
	kW	124,252	133,042	133,042	128,682	128,682	127,463	128,427	128,427
Sentinel Lights	#	660	682	682	464	464	432	432	401
	kWh	886,600	1,091,658	1,091,658	1,308,319	1,308,319	1,216,724	708,771	659,151
	kW	2,813	2,662	2,662	2,574	2,574	3,314	1,930	1,795
Street Lighting	#	8,078	8,238	8,238	8,324	8,324	8,431	8,431	8,540
	kWh	5,712,327	6,283,519	6,283,519	6,588,942	6,588,942	6,673,815	6,181,896	6,261,525
	kW	17,107	16,568	16,568	16,613	16,613	18,681	17,304	17,527
USL	#		10	10	10	10	10	10	9
	kWh		2,174,601	2,174,601	2,211,753	2,211,753	2,132,556	1,980,294	1,909,385
Total	#	42,020	42,630	42,630	42,949	42,949	43,391	43,391	43,840
	kWh	812,061,469	810,188,267	815,859,934	820,201,487	816,284,465	815,345,995	808,255,889	812,945,162
	kW	936,012	957,649	949,760	978,599	966,032	950,969	911,166	914,129

24. Customer Count, kWh load, kW load and Revenue – Ref: Exhibit 3 / Tab 2 / Schedule 2

In pages 1 to 3 of the referenced evidence, PDI has developed its load and revenue forecasts. While there is no precise method to measure the accuracy of an applicant's forecast until after the actual load has been met, the applicant's forecasting track record may provide some indication of its forecasting accuracy.

Please provide any data PDI has that illustrates the accuracy of its previous load forecasts.

Response:

The referenced evidence provides the method used by PDI to prepare the weather normalized load forecast as required by the Filing Requirements dated November 14, 2006. In this regard, PDI only prepared the weather normalized load forecast for the purposes of this Application and has previously not done such a forecast. As a result there are no previous weather normalized load forecasts available to judge the accuracy of the forecast.

25. Re-filing evidence – Ref: Exhibit 3

Some of PDI's evidence may require to be adjusted in light of responses to the preceding customer count, load and revenue forecasting interrogatories.

Please re-file any Exhibit 3 tables that require to be updated as a result of changes in the evidence.

Response:

PDI's evidence does not need to be adjusted in light of PDI's responses to the preceding customer count, load and revenue forecasting interrogatories.

26. Other Revenue – Ref: Exhibit 1 / Tab 2 / Schedule 4 and Exhibit 3 / Tab 3 / Schedule 1

In Exhibit 1 / Tab 2 / Schedule 4 / page 1, for 2009 PDI shows the "Other Operating Revenue (Net)" to be $1,618,851 and in Exhibit 3/ Tab 3 / Schedule 1 / page 1 it shows the "Other Distribution Revenue" to be $1,530,851.

Please reconcile these two values.

Response:

Other Distribution Revenue of $1,530,851 excludes $88,000 of SSS Admin Fees.

Exhibit 4 - Operating Costs

27. OM&A Expenses – Ref: Exhibit 4 / Tab 1 /Schedule 1

The figures in the following table are taken directly from the public information filing in the Reporting and Record-keeping Requirements ("RRR") initiative of the OEB. The figures are available on the OEB's public website.

		Col. 1 **2003**	*Col. 2* **2004**	*Col. 3* **2005**
1	**Operation**	$606,142	$554,522	$640,777
2	**Maintenance**	$1,572,206	$1,596,006	$1,790,016
3	**Billing and Collection**	$1,439,588	$2,062,759	$1,940,253
4	**Community Relations**	$68,803	$84,274	$609,056
5	**Administrative and General Expenses**	$1,199,462	$1,029,667	$989,413
6	**Total OM&A Expenses**	$4,886,201	$5,327,227	$5,969,514

a) Please confirm PDI's agreement with the numbers for Total OM&A Expenses that are summarized in the table.

Response:

PDI agrees with the numbers summarized in the above table.

Board staff prepared the following table to review Peterborough's OM&A expenses. Note that rounding differences may occur, but are immaterial to the questions below.

		Col. 1 **2006 Bd Appr.**	*Col. 2* **2006 Actual**	*Col. 3* **2007**	*Col. 4* **2008 Bridge**	*Col. 5* **2009 Test**
1	**Operation**	$554,522	$745,477	$910,111	$947,319	$956,517
2	**Maintenance**	$1,596,006	$2,395,581	$2,249,757	$2,175,251	$2,350,052
3	**Billing and Collection**	$2,098,572	$1,870,894	$1,915,268	$1,982,546	$2,026,703
4	**Community Relations**	$0	$485,827	$85,988	$0	$0
5	**Administrative and General Expenses**	$1,129,188	$1,151,315	$1,393,022	$1,346,618	$1,378,334
6	**Total**	$5,545,424	$6,786,819	$6,661,145	$6,575,734	$6,836,846

Board Staff prepared the following table 3 to review PDI's OM&A forecasted expenses from the evidence provided in Exhibit 4. Note rounding differences may occur, but are immaterial to the following questions.

Peterborough Distribution Incorporated

	2006		2006		2007		2008		2009	
	Board Approved	Variance 2006/2006	Actual	Variance 2007/2006	Actual	Variance 2008/2007	Bridge	Variance 2009/2008	Test	Variance 2009/2006
Operation	554,522	190,955	745,477	164,634	910,111	37,208	947,319	9,198	956,517	211,040
		34.4%		22.1%		4.1%		1.0%		28.3%
Maintenance	1,596,006	799,575	2,395,581	-145,824	2,249,757	-74,506	2,175,251	174,801	2,350,052	-45,529
		50.1%		-6.1%		-3.3%		8.0%		-1.9%
Billing & Collections	2,098,572	-227,678	1,870,894	44,374	1,915,268	67,278	1,982,546	44,157	2,026,703	155,809
		-10.8%		2.4%		3.5%		2.2%		8.3%
Community Relations	0	485,827	485,827	-399,839	85,988	-85,988	0	0	0	-485,827
		-		-82.3%		-100.0%		-		-100.0%
Administrative and General Expenses	1,129,188	22,127	1,151,315	241,707	1,393,022	-46,404	1,346,618	31,716	1,378,334	227,019
		2.0%		21.0%		-3.3%		2.4%		19.7%
Total OM&A Expenses	5,378,288	1,270,806	6,649,094	-94,948	6,554,146	-102,412	6,451,734	259,872	6,711,606	62,512
		23.63%		-1.43%		-1.56%		4.03%		0.94%

b) Please confirm that PDI agrees with the three tables prepared by Board staff presented above. If PDI does not agree with any table please advise why not and provide amended tables with full explanation of changes made. Please complete the tables for 2006 Board Approved and 2006 Actual.

Response:

PDI agrees with table 1.

PDI does not agree with table 2 as the totals are incorrect. It appears that Board staff have included taxes other than income taxes in table 2. PDI has prepared and provided a revised table (please see below) with accurate calculations based on the OM&A expense categories shown by staff in table 2.

REVISED TABLE 2

		Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*
		2006 Bd Appr.	**2006 Actual**	**2007**	**2008 Bridge**	**2009 Test**
1	**Operation**	$554,522	$745,477	$910,111	$947,319	$956,517
2	**Maintenance**	$1,596,006	$2,395,581	$2,249,757	$2,175,251	$2,350,052
3	**Billing and Collection**	$2,098,572	$1,870,894	$1,915,268	$1,982,546	$2,026,703
4	**Community Relations**	$0	$485,827	$85,988	$0	$0
5	**Administrative and General Expenses**	$1,129,188	$1,151,315	$1,393,022	$1,346,618	$1,378,334
6	**Total**	$5,378,288	$6,649,095	$6,554,147	$6,451,734	$6,711,606

PDI agrees with table 3.

c) Please complete the following table by identifying the key cost drivers (increase or decrease) that are contributing to the overall increase of 2006 Historical relative to 2009 cost levels.

Response

PDI has completed the table as requested:

		Col. 1	*Col. 2*	*Col. 3*	*Col. 4*
		2006	**2007**	**2008**	**2009**
	Opening Balances	**$5,969,514**	**$6,649,095**	**$6,554,147**	**$6,451,734**
1.	Labour & benefits	**155,000**	**151,000**	**187,000**	**(23,000)**
2.	GIS Tech .5, 2008	**0**	**0**	**30,000**	**33,000**
3.	Storm Damage	**437,000**	**(427,000)**	**0**	**29,000**
4.	Software & Equipment Rent	**59,000**	**0**	**24,000**	**34,000**
5.	Environmental clean-up	**0**	**168,000**	**(53,000)**	**(115,000)**
6.	Inflation & other	**29,000**	**0**	**0**	**0**
7.	ESA	**20,000**	**0**	**0**	**0**
8.	Line Reframing	**0**	**25,000**	**(25,000)**	**0**
9.	Wholesale meter charges	**0**	**31,000**	**(31,000)**	**0**
10.	SCADA connections	**30,000**	**0**	**0**	**0**
11.	Bad debts	**0**	**101,000**	**(98,000)**	**55,000**
12.	Conservation and PR	**0**	**42,000**	**(50,000)**	**10,000**
13.	Failed meter sample group, purchases	**0**	**30,000**	**0**	**0**
14.	PCB Testing	**0**	**0**	**0**	**100,000**
15.	Tree Trimming	**15,000**	**0**	**0**	**15,000**
16.	Pole Inspections	**0**	**0**	**0**	**20,000**
17.	Rate Application	**0**	**0**	**0**	**100,000**
18.	CDM	**(66,000)**	**(400,000)**	**(86,000)**	**0**
	Closing Balances	**$6,649,095**	**$6,554,147**	**$6,451,734**	**$6,711,606**

28. OM&A Expenses – Ref: Exhibit 4 / Tab 2 /Schedule 3

This Schedule contains a variance analysis for OM&A. Board staff are interested in more detailed explanations for the following variances:

a) It appears that some of the variances are incorrect. Please review the table for accuracy of data and variance calculations and provide a corrected version.

Response:

The table has been revised and is provided below. The following are the changes from the original table:

Account 5065 Meter Expense:

- 2006 variance changed from $26,586 to $0
- 2008 variance changed from $31,125 to $0
- 2009 variance changed from $5,887 to $0

Account 5670 Rent

- 2008 variance changed from $0 to ($143,205)

Description	2006 Board approved EDR $	2006 Actual $	Variance from 2006 EDR	2007 Actual $	Variance From 06 actual	2008 Bridge $	Variance From 07 actual	2009 Test $	Variance From 08 Bridge
OPERATIONS									
5010 - Load Dispatching	197,110	275,603	**78,493**	348,101	**72,498**	330,976	**0**	329,164	**0**
5020 - Distribution Lines & Feeders - Operating Labour	57,885	107,755	**49,870**	107,900	**0**	105,539	**0**	105,683	**0**
5065 – Meter Expense	65,659	92,245	**0**	147,978	**55,733**	179,103	**0**	184,990	**0**
MAINTENANCE									
5110 – Maintenance of Buildings and Fixtures	116,869	99,477	**0**	153,949	**54,472**	104,572	**(49,377)**	113,627	**0**
5114 – Maintenance of Distribution Station Equipment	169,640	329,735	**160,095**	336,974	**0**	336,754	**0**	305,136	**0**
5125 – Maintenance of Overhead Conductors and Devices	516,760	639,835	**123,075**	544,406	**(95,430)**	546,388	**0**	629,448	**83,060**
5130 – Maintenance of Overhead Services	131,545	419,237	**287,692**	215,427	**(203,810)**	203,350	**0**	214,696	**0**
5135 – Overhead Distribution Lines and Feeders – Right of Way	144,188	196,180	**51,993**	344,878	**148,698**	352,500	**0**	344,009	**0**
5160 – Maintenance of Line Transformers	91,395	182,845	**91,450**	161,977	**0**	146,612	**0**	240,937	**94,325**
BILLING and COLLECTIONS									
5305 – Supervision	137,963	119,445	**0**	162,975	**0**	275,933	**112,958**	276,232	**0**
5310 – Meter Reading Expenses	114,051	78,992	**0**	82,228	**0**	0	**(82,228)**	0	**0**
5315 – Customer Billings	876,317	847,774	**0**	793,060	**(54,714)**	864,755	**71,695**	858,850	**0**
5320 – Collecting	745,374	751,800	**0**	703,280	**0**	766,858	**63,578**	761,621	**0**
5335 – Bad Debt Expense	223,867	73,100	**(150,767)**	174,143	**101,043**	75,000	**(99,145)**	130,000	**55,000**
COMMUNITY RELATIONS									
5415 – Energy Conservation	**0**	**485,826**	**485,826**	**85,988**	**(399,838)**	**0**	**(85,988)**	**0**	**0**

ADMINISTRATIVE and GENERAL EXPENSES									
5630 – Outside Services Employed	251,142	144,825	**(106,317)**	153,672	**0**	164,786	**0**	260,021	**95,235**
5655 – Regulatory Expenses	6,584	93,296	**86,712**	110,380	**0**	120,000	**0**	120,000	**0**
5660 – General Advertising Expenses	84,274	39,167	**0**	82,024	**0**	30,690	**(51,334)**	40,720	**0**
5670 – Rent	606,177	673,890	**67,713**	841,582	**167,692**	698,377	**(143,205)**	732,407	**0**
AMORTIZATION EXPENSES									
5705 – Amortization Expense – Property, Plant and Equipment	**2,678,878**	**2,900,527**	**221,649**	**3,149,121**	**248,594**	**3,224,320**	**75,199**	**3,540,000**	**315,680**

b) Account 5010, Load Dispatching, a seemingly fixed cost of distribution, has historical variances from a low $197K in 2004 to a peak of $348K in 2007, a variance of 75%. Other years also display large year to year swings. Please explain the basis for the swings.

Response:

The direct labour costs have not changed over this period, however, the administrative cost allocation within PDI to the various O&M activities was updated in 2007. The 2007 actual, the 2008 Bridge Year and the 2009 Test Year costs are consistent.

This allocation does not affect the total cost of PDI operations, as illustrated in the response to question 27(c), above.

c) Account 5065, Meter Expenses has increased 100% from $92K in 2006 to $185K for the 2009 test year.

i. Please explain the drivers for this increase.

Response:

The increase in the Meter Expense from 2006 to 2009 is primarily due to the commissioning of new wholesale meter points as required by the Market Rules.

Communication costs have increased by $28,000 and MSP costs of $17,000 have been transferred from account number 5630.

Labour has also increased by $47,000 in anticipation of costs associated with the smart meter activities.

ii) Please define the acronym “MSP” found at page 8 of 13.

Response:

“MSP” is the acronym for Meter Service Provider.

iii. Are any of these costs related to smart meters?

Response:

Labour costs of $47,000 in anticipation of smart meter activities have been included.

d) Account 5110, Maintenance of Buildings and Fixtures for 2007 has an explanation on page 8 of 13 stating that the variance from 2006 is due to Reframing to correct a clearance problem at MS 29 Feeder #2. Please define “reframing”. What was the cost of the reframing?

Response:

The overhead distribution pole line was “re-framed” (reconstructed) to increase line-to-line electrical clearance. The cost of the reframing was estimated to be $25,000**.**

e) Account 5125, Maintenance of Overhead Conductors and Devices is explained on page 12 as being based on the 2007 actuals. The increase from 2007 to 2009 is $85,000, a 15.6% increase. Please provide details for the increase.

Response:

As the Board noted in its Combined Proceeding for Storm Damage Cost Claims (Board file no. EB-2007-0571), “It is the Board’s expectation that Distributors will identify a forecast for storm damage costs within their greater O&M forecast.”

PDI has increased the forecasted 2009 storm costs by $30,000. The 2009 forecast also included increased cost related to switch maintenance. As part of its Asset Management review, it is PDI’s intention to re-start a formal switch maintenance program. The maintenance program has lagged due to the increased capital activity. The increase from 2006 Actual to the 2009 Test Year amount is $55,000.

f) Account 5130, Maintenance of Overhead Services decrease by $203,810 in 2007 compared to 2006. Please explain.

Response:

2006 expenses included costs of $257,000 related to significant windstorm damage. 2007 expenditures returned to normal expenditure levels.

g) Account 5135, Maintenance Overhead Distribution Lines and Feeders includes costs for tree trimming. On page 6, PDI states that tree trimming is on a three year basis. In its application before the Board, EB-2007-0681, Hydro One Networks Inc. stated that it was intending to reach an optimum cycle of eight years for their vegetation management programme.

i. Has PDI assessed its 3-year programme relative to other cycle periods?

ii If so, what were the results?

iii If not, would a longer cycle period not provide sufficient vegetation management to protect plant at a lower annual cost?

Response:

The three-year cycle is seen by PDI as the most optimum level for the Peterborough and area considering the reliability improvements from reduced tree contacts. Reduced overtime and reactive maintenance expenses from tree outages have been realized (e.g. one outage due to a tree limb from heavy wind storms on Dec 28th and 29th, 2008). Trimming clearances are closer for urban trimming as compared to rural right of ways for aesthetic reasons. Given the high density of trees, recent increased growth rates in Peterborough and the reliability experience from tree-related outages, PDI believes its three-year cycle is appropriate. The three-year cycle has evolved from a five-year cycle used more than a decade ago.

h) Account 5310, Meter Reading for 2008 and 2009 has no costs for billing. Where are these costs reported?

Response:

PDI's Customer Service Technical department was closed, and the costs associated with the activities formerly carried on by that department are included in account 5305 – Billing and Collecting Supervision – and account 5065 – Distribution Expenses, Meter Expenses.

i) Account 5315, Customer Billings increased by $71,695 or 8.3% in 2008 compared to 2007. The explanation provided states that:

> "Increased IT support to Customer Service as well as an increased allocation of the PUSI Customer Service department of $117K. The Peterborough Group of companies discontinued Collection Agency and Utility Billing Services activities. Both of these activities shared in Customer Service allocations from PUSI. The result is a smaller allocation base and increased cost to PDI and its affiliates."

i. Please show how a reduction from eliminating costs in one function, results in increased allocations of $117K.

Response:

Utility Billing Services was a product line of Peterborough Utilities Inc. Utility Billing Services provides sales, billing and collecting services to multi unit residential and commercial buildings. They were not the billings service provider for PDI. However, as part of the Peterborough Utilities Group they shared in the allocation of Corporate Administrative costs.

PUSI has been the billing service provider since 2000.

Corporate allocations are based upon the service level demands of the Peterborough Group of companies and as such the fixed customer service costs incurred by PUSI are allocated to the group of companies on a reduced number of activities thereby increasing cost drivers and the total allocated costs.

Prior to the elimination of the related business, PDI benefited from reduced billing and service costs. Through operating efficiencies and cost sharing PDI's Billing and Collection costs have decreased 3.4% from the 2006 Board Approved EDR to the 2009 Test Year.

ii. If the "Peterborough Group" no longer provided billing services, are the costs of the billing service provider included in Account 5315?

Response:

The billing service costs have been included in account 5315. Peterborough Utilities Services Inc., a member of the Peterborough group of companies, is still providing billing services.

iii. What are the net savings from changing to a billing service provider in 2008 and forecast 2009?

Response:

There is no change in the billing service provider.

iv. If the billing service provider also provides services to affiliates of PDI, are the bills separate?

Response:

No, the bills are not separate.

v. If the bills in iv. are not separate, how are the billed expenses allocated?

Response:

Direct allocations are made to an associated company on the following basis:

% of total customers for shared costs such as envelopes and postage;

Number of charge codes; and

Number of line items.

j) Account 5320, Collecting increased by $63,578 or 8.3% in 2008 compared to 2007. The explanation given is similar to that for Account 5315.

i. Please show how a reduction from eliminating costs in one function, results in increased allocations of $117K.

Response:

As discussed in the context of account 5315 in question (i)(i) above, Utility Billing Services was a product line of Peterborough Utilities Inc. Utility Billing Services provides sales, billing and collecting services to multi unit residential and commercial buildings. They were not the billings service provider for PDI. However, as part of the Peterborough Utilities Group they shared in the allocation of Corporate Administrative costs.

PUSI has been the billing service provider since 2000.

Corporate allocations are based upon the service level demands of the Peterborough group of companies, and as such the fixed customer service costs incurred by PUSI are allocated to the group of companies on a reduced number of activities thereby increasing cost drivers and the total allocated costs.

Prior to the elimination of the related business, PDI benefited from reduced billing and service costs. Through operating efficiencies and cost sharing PDI's Billing and Collection costs have decreased 3.4% from the 2006 Board Approved EDR.

ii. If the "Peterborough Group" no longer provided collection services, are the costs of the collection service provider included in Account 5320?

Response:

Collection service costs have been included in account 5320. Peterborough Utilities Services Inc., a member of the Peterborough group of companies, namely still provides collection services.

iii. What are the net savings from changing to a collections service provider in 2008 and forecast 2009?

Response:

There is no change in the collections service provider.

iv. If the collections service provider also provides services to affiliates of PDI, are the bills separate?

Response:

No, the bills are not separate.

v. If the bills in iv. are not separate, how are the billed expenses allocated?

Response:

As noted in response to (i) above, direct allocations are made to an associated company on the following basis:

% Of total customer for shared costs such as envelopes and postage;
Number of charge codes; and
Number of line items.

k) Account 5660, General Advertising Expenses decrease by $51,334 for 2008 compared to 2007. These costs then rise $10,000 for 2009.

i Please explain the variances.

Response:

The 2009 expenses include $35K for Peterborough Green Up. This was missed in the 2008 budget, the 2008 forecast and the 2009 budget. The increase of $10,000 from 2008 to 2009 is primarily for a customer relocation guide (an expenditure of approx. $4,000) and $6,000 in radio and newspaper advertisements primarily for smart meters.

ii What are the general advertising expenses for 2008 and 2009?

Response:

Please see the table on the following page.

General Advertising Expenses Account 5660	**2008 Bridge**	**2009 Test**
Billing Stuffers	11,200	11,200
Public advertisements	1,340	3,350
Radio Advertisements	1,500	5,500
Smart Meter Education	6,000	6,000
FUSE	6,300	6,300
Relocation Guide	0	4,020
Home Show	2,310	2,310
Miscellaneous	2,040	2,040
Total	**$30,690**	**$40,720**

l) Account 5670, Rent increases between 2006 and 2007 by $167,692. It appears that Rent decreases by $143,200 from 2007 to 2008, and then rises by $34,000 for 2009. Please explain these variations.

Response:

The building rent increase in 2007 is directly related to an environmental clean-up expense of $167,000. The cost incurred by PUSI related to a small transformer oil leak. The oil was traced to the staffing area at the rear of the garages where used transformers are handled and repaired. After site investigation and testing by an environmental consultant and in cooperation with the Ministry of the Environment it was determined that the soil was to be removed and replaced with new material. These costs were allocated to PDI with no mark-up from PUSI. The decrease from 2007 to 2008 is related to the removal of the one time clean-up costs. The increase from 2008 to 2009 of $34,000 is due to an increase in equipment and software rental charges. The rental charge is based upon amortization and the capital additions have been greater in the past couple of years compared to 5 years ago**.**

29. OM&A Expenses – Ref: Exhibit 4 / Tab 2 /Schedule 3

The summary table on page 1 of the referenced evidence indicates for Account 5655, Regulatory Expenses are $120,000 for 2008 and 2009.

a) Please provide the breakdown for actual and forecast, where applicable, for the "2006 Board approved", 2006 actual, 2007 actual, 2008 bridge year, and 2009 Test Year regarding the following regulatory costs and present it in the following table.

b) Under "Ongoing or One-time Cost", please identify and state if any of the regulatory costs are "One-time Cost" and not expected to be incurred by the applicant during the impending period when the applicant is subject to the 3rd Generation IRM process or it is "Ongoing Cost" and will continue throughout the 3rd Generation of IRM process.

c) Please state PDI's proposal on how it intends to recover the "One-time" costs as part of its 2009 rate application if it is not included in the 3rd Generation IRM process two year amortization.

Response:

One-time costs associated with this Application have been recorded in account 5630 – Outside Services Employed. The 2009 Test Year amount of $260,021 includes $100,000 for this Application, including, among other elements, assistance with the interrogatory and hearing processes. One time costs will have been fully recovered in the 2009 rate year, and management anticipates that there will be additional costs through the 3rd Generation IRM process related to ongoing and new OEB initiatives and other regulatory matters that have not been accounted for in other accounts. In other words, PDI anticipates that the costs related to regulatory matters included in this Application will continue through the 3rd Generation IRM period.

PDI has completed the table as requested in paragraph (a) above – please see the following page.

	Regulatory Cost Category	Ongoing or One-time Cost?	2006 Board Approved	2006 Actual	2007 Actual	% Change in 2007 vs. 2006	2008 (As of Sept 2008)	% Change in 2008 vs. 2007	2009 Test Year	% Change in 2009 vs. 2008
1.	OEB Annual Assessment		6,584	90,067	98,737	8,670	89,512	(9,225)	100,000	10,488
2.	OEB Hearing Assessments (applicant initiated)									
3.	OEB Section 30 Costs (OEB initiated)			882	9,786	8,904	6,009	(3,777)	18,000	11,991
4.	Expert Witness cost for regulatory matters									
5.	Legal costs for regulatory matters									
6.	Consultants costs for regulatory matters									
7.	Operating expenses associated with staff resources allocated to regulatory matters									
8.	Any other costs for regulatory matters (please define)									
9.	Operating expenses associated with other resources allocated to regulatory matters (please identify the resources)									
10.	Other regulatory agency fees or assessments									
11.	Other		0	2,347	1,860	(487)	2,060	200	2,000	(60)

30. OM&A Expenses – Ref: Exhibit 4 / Tab 2 / Schedule 1

On page 3 of the referenced evidence PDI itemizes the costs by account for the functional areas of the Company for OM&A expenses.

a) For the 2009 forecast test year, please identify and describe any one time costs other than those explained for regulatory costs in the previous question.

Response:

There are no additional one time costs.

b) Are there any one time costs that were inadvertently carried forward from previous years?

Response:

No, there are no one time costs that have been inadvertently carried forward from previous years.

c) Are there any expenses for charitable donations in the 2009 forecast? If there are please identify them.

Response:

There are no donations in the 2009 forecast.

d) Are there any costs in the forecast for conversion due to the adoption of International Financial Reporting Standards? If there are please itemize the costs and the rational of the drivers of the costs.

Response:

There are no additional IFRS costs within the 2009 rate application as PDI has not yet assessed or budgeted for the potential IFRS cost.

e) Does PDI partake in any Winter Warmth or other programs to assist low income customers? If so what are the programs and their costs for 2009?

Response:

PDI has contributed $30,000 towards Funds for Utility Service Emergencies, FUSE, in both 2006 and 2007. An additional $5,000.00 has been provided to the Housing Resource Centre for administration of the fund. The funding level for 2009 remains unchanged.

PDI has a close working relationship with the Housing Resource Centre. In addition to the 14,000+ pay arrangements PDI makes annually allowing customers to clear their arrears and avoid disconnection, PDI also pro-actively directs customers who are having difficulty paying their utility bills to the Housing Resource Centre to investigate whether they may qualify for FUSE funding.

f) Please identify any programs in the 2009 forecast that are specifically aimed at productivity and efficiency improvements.

Response:

The implementation of the work order system will help streamline Engineering and Operation processes and provide better costing and information for use in the Asset Management Plan and the budget process. PDI is also looking at the contracting out of some of the lower skill level service work (e.g. civil related work and low voltage residential service installations) and reviewing its work scheduling to better utilize its crew resources. PDI is also implementing an online electric service request for new and upgraded service connections to streamline data gathering from potential customers.

g) What inflation rate is used for 2009 and what is the source document for the inflation assumptions.

Response:

3% inflation was used as 80% of operating and maintenance expenses are labour related. The PUSI contract includes a 3% labour increase.

31. Corporate Cost Allocation used to allocate Shared Services – Ref: Exhibit 4 / Tab 2 / Schedule 4

a) The five principles listed below formed the basis of the Board's acceptance of Enbridge's corporate cost allocations:
   i) The service is specifically required by the utility;
   ii) The level of service provided is required by the utility;
   iii) The costs are allocated based on cost causality and cost drivers;
   iv) The cost to provide the service internally would be higher and the cost to acquire the service externally on a stand-alone bases would be higher; and
   iii) There are economies of scale.

Please comment in how PDI's corporate cost allocations policy meets each of these principles.

Response:

Cost allocations from PUSI to PDI meet the above principles in the following ways:
1. All direct costs specifically required by PDI are tracked via a unique job cost number.
2. The level of service provided is in compliance with the SLA between the two companies.
3. Costs are based upon a cost/causation relationship. All direct cost are allocated via item 1, and indirect costs are allocated on a number of department specific cost drivers. For example, with respect to Finance, the drivers include:
   i. Number of accounts payable invoices
   ii. Number of accounts receivable invoices
   iii. Number of general ledger adjustments
4. The cost to PDI for administrative support such as Human Resources, Finance, and Purchasing would be higher if provided internally by PDI or outsourced as they are being charged a percentage of a full department with minimal cost recovery included by PUSI.
5. PDI shares in the benefits of a highly diverse executive and management group. This includes not having to pay 100% of the costs associated with the Management. As PUSI adds resources, costs are allocated to the appropriate companies and PDI has the ability to draw on these resources as required.

b) It appears to Board staff that the activity based cost system that allocates costs from Peterborough Utilities Services Inc. ("PUSI") to affiliates is job based. Further, all services provided to all of the affiliates by PUSI are based on three fundamental drivers; labour, equipment, and material. The costs of these drivers are accumulated by jobs. To these costs are added the allocated departmental, administrative, and general expenses.

Please confirm if Board staff's interpretation as stated is correct. If not, please clarify.

Response:

The above drivers are the basis for allocating direct operating and capital cost. Indirect cost, administrative support, is allocated via department specific drivers.

c) Has the costing methodology developed by Corporate Renaissance Group been reviewed by an independent third party to ensure appropriate Board approved principles have been followed and applied as stated above in a) and those found in the Affiliate Relationship Code? If yes, please provide a copy of the report. If no, then please provide the following, preferably in tabular format:

i. Please itemize, by major expense category (Operations, Maintenance, Billing, etc.) the jobs acquired by PDI from PUSI. The itemization can be in a general way, overhead lines maintenance, meter repair, etc.

Response:

The methodology developed by CRG has not been reviewed by an independent third party. The table on the following page provides the requested itemization of the jobs acquired by PDI from PUSI.

Activity/ / Dept	Electric Operations	Field Technology	Engineering	Finance	Administration	Technology Services	Customer Service	Corporate Services	Human Resources	Purchasing	Stores
OH Subtransmission	X										
OH Lines	X										
General Maintenance	X		X								
OH Services	X										
UG Subtransmission	X										
UG Lines	X		X								
UG Services	X										
Control Centre	X		X								
Substation Maintenance	X	X									
Meter Maintenance	X	X									
Transformer Maintenance		X									
Billing & Collecting							X				
Administrative Support			X	X	X	X	X	X	X	X	X

ii. For each itemization in i. please describe the overheads and the allocator to the jobs.

Response:

As indicated in Exhibit 4, Tab 2, Schedule 4, Pages 6 to 14, the allocation basis is as follows:

Electric Operations –	Direct charge via job cost system
Field Technical –	Direct charge via job cost system
Engineering –	Direct cost via job cost system, Administrative support cost are allocated as a % of the engineering direct activities
Finance -	Direct , in respect of special projects Number of accounts payable and receivable Invoices, general ledger entries
Administration-	Labour hours charged out to all direct operating and capital activities
Technology Services-	All costs are run through a separate ABC system to determine the levels of support for the City of Peterborough and to PUSI. PUSI costs are then assigned to a job cost, which indicates the department that is receiving the support. Costs are then attributed to a department, which in turn allocates costs to an operating department and/or to an associated company.
Customer Service	Direct to an associated company; percentage of total customers; number of line items on a bill; number of bill codes
Human Resources	Direct to an associated company; labour hours charged out to all direct operating and capital activities
Purchasing	Number of purchase requisitions and number of purchase orders
Stores	Stores expense is captured as on overhead on all stores issues

iii. If there are secondary allocations, such as departmental costs, administrative costs, etc. allocated to the overheads (e.g. human resources costs to IT personnel), please explain those overheads and the allocators.

Response:

Please see the response above.

d) On page 2 of the referenced evidence, Overhead 2 is described as the cost of capital recovery on direct labour. Please explain.

Response:

PUSI charges a return on labour in its pricing of services provided to affiliates. PDI's understanding is that PUSI's pricing to its affiliates is lower than its pricing to third parties for similar services.

e) On page 2, PDI describes two inventory charge-out codes, code 1 for internal jobs, and code 2 for external jobs. Are code 2 charge-outs always equal to or greater than code 1?

Response:

There is only one inventory overhead charge code. Page 2 describes the vehicle and equipment subsystem as having 2 charge codes. With respect to the vehicle and equipment subsystem, Code 2 charge-outs are greater than code 1 charge-outs. PDI is charged the code 1 rates.

f) On page 5, PDI indicates that affiliate transactions from Peterborough Utilities Inc. are at market rates.
   i. Please explain how market rates are established.

Response:

PUI currently has 96 MDMA, 28 MSP and 4 Settlement clients. PDI receives the same market rate as other clients of PUI.

PUI provides the following services to PDI:

1. Settlement Services
   a. Retrieval and storage of preliminary statements, final statements, and invoices from the Independent Electricity System Operator (IESO).
   b. Calculation of Net System Load (NSL)
   c. Input and storage of retail and wholesale meter data required to facilitate NSL calculations. This includes wholesale check meters, interval meters, generation meters, streetlight profiles, and load transfer meters. Automated reads of these meters are also offered as a separate service.

d. Retrieval and storage of all wholesale check meter data from the IESO's MV-Web system, and reconciliation of all wholesale meter data.
e. Reconciliation of commodity charges between the preliminary statement and values calculated from meter reads and electricity spot prices.
f. Reconciliation of IMO invoices against the preliminary and final statements.

In 2004 wholesale settlement services were provided by Enerconnect. Since April 2005 PUI has provided wholesale settlement services resulting in annual savings of $125,000

2. Meter Data Management Agency
    a. Manage the collection and storage of data from remote interval or "smart" meters using industry standard software.
    b. Validate, Edit and Estimate (VEE) meter data, as required, according to strict IESO parameters for the Wholesale Market as well as industry-standard Retail VEE rules.
    c. Prepare and send formatted files and reports to Billing/CIS departments as well as Settlement Services Bureau.
    d. Resolve Metering and Meter Data issues through our anomalous status reporting.
    e. Secure and store data off-site so it's always safe and always available should it be required.
    f. Manage meters including programming, synchronizing time and administrating passwords and device access.

3. Meter Service Provider
    a. PUI is a registered with the IESO as Meter Service Provider (MSP) #1002.
    b. As an MSP, PUI guarantees a level of service that conforms to the high standards of the wholesale market.

ii. Is there a mark-up applied to the market rates?

Response:

There is no mark-up on the negotiated market rates.

32. The “PUSI Service Agreement with PDI” – Ref: Exhibit 4 / Tab 2 / Schedule 4 / Appendix A

PDI has filed in the referenced evidence a copy of the “PUSI Service Agreement with PDI”. On page 7, Article Three, Section 3.1, the Term of the Agreement is defined to be in effect until June 30, 2007. Section 3.1 also allows automatic renewal for successive five year periods.

a) Has the agreement renewed itself automatically?

Response:

The agreement was renewed by PDI’s Board of Directors in May, 2007 for a five-year term.

b) If no, is a new agreement being negotiated and what is the status of the negotiations?

Response:

N/A

33. The proposed levels for 2009 Shared Services and other O&M spending – Ref: Exhibit 4 / Tab 2 / Schedule 4

Table 1 on page 13 of the referenced evidence provides a summary of PUSI shared services with PDI. Board staff have created the following table from the data provided in Table 1 to asses the increases in shared services costs in total.

		col. 1	*col. 2*	*col. 3*	*col. 4*	*col. 5*	*col. 6*	*col. 7*	*col. 8*
		Year to Year Change ($)				**Year to Year Change (%)**			
		07/06	**08/07**	**09/08**	**09/06**	**07/06**	**08/07**	**09/08**	**09/06**
1	Electric Distributor Operations	-197,958	260,429	7,154	69,625	10.5%	15.4%	0.4%	3.7%
2	Engineering Services	174,540	53,079	17,242	244,861	23.1%	5.7%	1.8%	32.5%
3	Field Technical Operations	46,076	136,873	33,743	216,692	11.9%	31.5%	5.9%	55.8%
4	Customer Service	-4,915	116,175	-31,485	79,775	-0.4%	9.0%	-2.2%	6.1%
5	Administration	122,420	-37,504	73,644	158,560	33.7%	-7.7%	16.4%	43.6%
6	Corporate & Regulatory Services	19,652	27,524	13,085	60,261	8.1%	10.5%	4.5%	24.8%
7	Finance	-7,887	4,799	2,014	-1,074	-4.3%	2.8%	1.1%	-0.6%
8	Information Technology	4,692	49,245	20,642	74,579	0.8%	8.7%	3.4%	13.3%
9	Human Resources	80,642	22,156	23,073	125,871	46.5%	8.7%	8.4%	72.6%
10	Purchasing	5,521	10,428	1,514	17,463	10.1%	17.4%	2.1%	32.0%
11	Vehicles	10,450	-54,540	25,000	-19,090	2.5%	12.7%	6.6%	-4.5%
12	Building Rent	173,456	-136,348	-255	36,853	36.4%	21.0%	0.0%	7.7%
13	Software & Equipment	-5,765	-6,857	34,285	21,663	-2.9%	-3.6%	18.5%	11.0%
14	**Total**	420,924	445,459	219,656	1,086,039	6.0%	6.0%	2.8%	15.5%

a) Please confirm that PDI agrees with the table prepared by Board Staff. If PDI does not agree with the table please advise why not and provide an amended table with a full explanation of changes made.

Response:

PDI does not agree with the table, as the year to year changes in % terms are not entirely correct. Please see the revised table below.

		col. 1	*col. 2*	*col. 3*	*col. 4*	*col. 5*	*col. 6*	*col. 7*	*col. 8*
		Year to Year Change ($)				**Year to Year Change (%)**			
		07/06	**08/07**	**09/08**	**09/06**	**07/06**	**08/07**	**09/08**	**09/06**
1	Electric Distributor Operations	-197,958	260,429	7,154	69,625	**-10.5%**	15.4%	0.4%	3.7%
2	Engineering Services	174,540	53,079	17,242	244,861	23.1%	5.7%	1.8%	32.5%
3	Field Technical Operations	46,076	136,873	33,743	216,692	11.9%	31.5%	5.9%	55.8%
4	Customer Service	-4,915	116,175	-31,485	79,775	-0.4%	9.0%	-2.2%	6.1%
5	Administration	122,420	-37,504	73,644	158,560	33.7%	-7.7%	16.4%	43.6%
6	Corporate & Regulatory Services	19,652	27,524	13,085	60,261	8.1%	10.5%	4.5%	24.8%
7	Finance	-7,887	4,799	2,014	-1,074	-4.3%	2.8%	1.1%	-0.6%
8	Information Technology	4,692	49,245	20,642	74,579	0.8%	8.7%	3.4%	13.3%
9	Human Resources	80,642	22,156	23,073	125,871	46.5%	8.7%	8.4%	72.6%
10	Purchasing	5,521	10,428	1,514	17,463	10.1%	17.4%	2.1%	32.0%
11	Vehicles	10,450	-54,540	25,000	-19,090	2.5%	**-12.7%**	6.6%	-4.5%
12	Building Rent	173,456	-136,348	-255	36,853	36.4%	**-21.0%**	0.0%	7.7%
13	Software & Equipment	-5,765	-6,857	34,285	21,663	-2.9%	-3.6%	18.5%	11.0%
14	**Total**	420,924	445,459	219,656	1,086,039	6.0%	6.0%	2.8%	15.5%

b) Board staff note that in most cases the total year over year increases are greater than those for the Operations, Maintenance and Administration expenses outlined in Question 27. Please explain the reasons for the operations budget experiencing different increases.

Response:

The above table represents the total shared service cost by department allocated from PUSI to PDI, which includes O&M and capital costs.

c) Has PDI changed its capitalization policy since 2004?

Response:

No, there has been no change in the capitalization policy.

d) Table 2 on page 14 is a summary of the 2009 intra-company cost allocations, expressed as percentage. A total for all allocations has not been shown. Board staff are interested in the percentage of total costs allocated to all affiliates. Please provide the percentage distribution of the total costs allocated to the affiliated companies stated in the table.

Response:

The percentage of total costs allocated to all affiliates is as follows:

PUC	38.8%
PDI	41.2%
PUI	5.6%
PTS/City	10.7%
PUSI	3.7%

e) Please complete the following table. Total compensation includes wages, benefits, incentive pay, and overtime.

Response:

The table has been completed as requested.

		Col. 1 **2006 BAP**	*Col. 2* **2006Act.**	*Col. 3* **2007**	*Col. 4* **2008**	*Col. 5* **2009**
1	Total Compensation	5,213,183	5,908,625	6,175,846	6,481,570	6,952,581
2	Less Capitalized Amount	1,767,952	1,919,311	2,035,394	1,852,446	2,576,981
3	Less Billable	0	0	0	0	0
4	Less Other	0	0	0	0	0
5	Compensation charged to OMA&G	3,445,231	3,989,314	4,140,452	4,629,124	4,378,600

34. 3rd Party Purchased Services – Ref: Exhibit 4 / Tab 2 / Schedule 5

In the referenced evidence, PDI has provided tables of 3rd party purchased services for 2006 and 2007 for purchases over $10,000.

a) Please provide similar tables for 2008 and forecast 2009 for purchases over $50,000.

Response:

2008 Third Party Purchases > $50,000

Vendor	2008 Amount	Description
Expercom Telecommunications	$460,077	UG rehabilitation
Aecon Utilities	$368,178	UG rehabilitation
Kawartha Utility Services	$251,892	Install port-a-holes, ground rods, anchors
Peterborough Utilities Inc	$176,550	Telecommuications, MSP, MDMA, WSS
O'Brien Tree Service	$132,093	Tree trimming
Borden Ladner Gervais	$126,726	Consulting services
Calder Construction	$75,228	UG service installation
MEARIE	$73,058	Liability insurance
Multi-Vac Services Ltd	$55,964	Vacuum truck rental

Vendors for 2009 purchases had not been selected at the time the 2009 budget was prepared. The following table shows the vendors known at this time.

2009 Third Party Purchases > $50,000

Vendor	2009 Amount	Description
Vendor to be determined	$500,000	UG line rebuild
K-Line Maintenance & Const.	$135,728	Underground installation
Peterborough Utilities Inc	$105,924	MSP, MDMA, WSS
O'Brien Tree Service	$105,758	Tree trimming
MEARIE	$75,200	Liability insurance
Calder Construction	$75,000	UG service installation
Atria Networks	$72,000	Telecommunications
Multi-Vac Services Ltd	$50,000	Vacuum truck rental

b) Please provide the total of 3rd party purchases under $50,000 for 2006 through to 2009 inclusive.

Response:

PDI has been unable to provide the total 3rd party purchases under $50,000 for 2006 through 2009 at this time.

c) For all purchases from 2006 to 2009, please indicate whether they are tendered, negotiated, or sole sourced.

Response:

The purchase of goods and services for PDI is the responsibility of PUSI's Purchasing and Materials Manager who issues and receives all quotations, tenders, contracts and proposals. Where competitive bids are required, the contract will normally be awarded to the lowest evaluated, responsive and responsible bidder, unless otherwise approved by the Board, or in the case of emergency purchases, or in the case of sole-source purchases approved by the appropriate signing authority.

Purchase Levels:

- $5,000 or less:
  - Periodic price checks and quotations are obtained.
- $5,000 to $35,000:
  - Competitive tenders and quotations are obtained where possible.
- $35,000+:
  - Advertised or invited tenders. Approval to tender obtained from a VP or from the President & CEO

35. The 2009 Human Resources related costs – Ref: Exhibit 4 / Tab 2 / Schedule 6

The referenced evidence states that labour is charged through the shared services fees. No description exists of manpower planning and productivity incentives.

a) Please describe the process for ensuring development planning and safety training.

Response:

The Human Resources department maintains a training matrix that outlines the required safety and technical training for each job classification within the Company. The matrix outlines the required safety courses, the length of the training and the frequency of training including re-certification requirements.

Copies of employee training certificates are kept in the employee's personnel file and are kept electronically in a Training Database. Reporting from the database enables the employee's supervisor and Human Resources to ensure that staff maintain current safety training and certifications.

Effective in 2009 all supervisory and management staff will have development plans developed during the performance management process which is to be completed by February 27, 2009. The performance management process for all union staff with have the same requirement to be implemented by December 31, 2009. Development plans will include any areas of weakness within the employee's current job requirements as well as development of skills and competencies for career development.

b) Does PDI have an incentive/performance pay plan?

    i) If yes, what productivity and efficiency goals are set for a) executive, b) management, and c) salaried employees?

Response:

PDI has been developing an incentive plan for all management levels but no incremental costs for that plan have been included in the Application.

ii) If yes, are quantifiable goals set, and how are they measured?

Response:

It is anticipated that the performance plan will address achieving best practices for operations and encompass items such as system performance and reliability, and employee and public safety, using metrics commonly used in the industry Additionally, a financial measure will be attainment of planned net earnings which is driven by planned operating cost improvements and efficiency. Reference to operating cost efficiency in relation to industry peers will be considered.

iii) If yes, are any incentives awarded for improved return to shareholders?

Response:

No, there are no shareholder return based metrics.

iv) If there is no incentive/performance pay, what incentive is there to strive for productivity and efficiency improvements?

Response:

As noted above, PDI is still developing the incentive pay program.

36. Determination of Loss Adjustment Factors

References:

i. **Exhibit 4 / Tab 2 / Schedule 8, page 1**
ii. **Exhibit 4 / Tab 2 / Schedule 8, page 2**
iii. **Exhibit 1 / Tab 1 / Schedule 12, page 1**

- The 1st reference provides a calculation of actual distribution loss factors (DLF) and total loss factors (TLF) for 2005 to 2007 and the average for the 3-year period.
- The 2nd reference provides a calculation of actual supply facility loss factors (SFLF) for 2005 to 2007 and the average for the 3-year period.
- The 3rd reference provides an explanation of host and embedded utilities.

a) With respect to the table in the 1st reference, please provide an explanation or rationale for proposing an average (of years 2005 to 2007) DLF (1.0413) for the test year 2009 rather than a lower DLF such as the actual DLF for 2006 (1.0319).

Response:

PDI is proposing an average DLF of 1.0413 reflecting the average of years 2005 to 2007 for the test year 2009 rather than a lower DLF such as the actual DLF for 2006 of 1.0319. PDI believes the 2006 DLF is particularly low and is concerned with adopting the 2006 DLF as the 2009 Test Year DLF as it could lead to increases in the amount payable to PDI from customers in account 1588 - RSVApower. PDI submits that using a 3 year average of 2005 to 2007 takes into account the 2006 results but is used to offset the higher DLF of 2005 and 2007 to a level which appears reasonable to PDI.

b) The industry standard for SFLF related to a distributor that is:
   - directly connected to the IESO controlled grid, is 1.0045
   - fully embedded within host distributor Hydro One, is 1.0340
   - partially embedded as in the case of Peterborough (3rd reference), is a weighted average of the above.

   In order to enhance the Board's understanding of the proposed SFLF of 1.0071 as provided in the 2nd reference, please provide a breakdown of Wholesale kWh (row A in the table in the 1st reference) that flow into PDI's distribution system (Asphodel-Norwood, Lakefield and Peterborough service areas), (i) directly from the IESO grid, and (ii) via the Hydro One distribution system.

Response:

The following tables illustrate the SFLF calculations:

Supply Facility Loss Factors

Table 1. Non-loss adjusted purchases, kWh's

	Actual 2005	Actual 2006	Actual 2007
Otonabee TS	488,271,867	470,897,130	489,531,717
Dobbin TS	302,695,451	292,058,091	304,183,570
Dobbin DS	44,147,450	44,645,826	45,425,247
	835,114,768	807,601,046	839,140,534
LSGS	22,908,929	26,700,638	18,046,118
Pumphouse	1,576,720	1,586,159	457,368
Trent	141,334	67,074	27,115
	859,741,751	835,954,917	857,671,135

Table 2. Loss adjusted purchases, kWh's

	Actual 2005	Actual 2006	Actual 2007
Otonabee TS	491,217,347	473,732,246	492,431,516
Dobbin TS	304,030,034	293,792,755	306,008,672
Dobbin DS	45,648,463	46,163,784	46,969,705
	840,895,845	813,688,784	845,409,893
LSGS	22,908,929	26,700,638	18,046,118
Pumphouse	1,576,720	1,586,159	457,368
Trent	141,334	67,074	27,115
	865,522,828	842,042,655	863,940,494

Table 3. Losses, kWh's

	Actual 2005	Actual 2006	Actual 2007
Otonabee TS	2,945,480	2,835,116	2,899,799
Dobbin TS	1,334,583	1,734,664	1,825,102
Dobbin DS	1,501,013	1,517,958	1,544,458
	5,781,076	6,087,737	6,269,359

Table 4. Weighted Average Loss Calculation

Loss %	Actual 2005	Actual 2006	Actual 2007
Otonabee TS	0.6032%	0.6021%	0.5924%
Dobbin TS	0.4409%	0.5939%	0.6000%
Dobbin DS	3.4000%	3.4000%	3.4000%
	0.6922%	0.7538%	0.7471%
LSGS	0.0000%	0.0000%	0.0000%
Pumphouse	0.0000%	0.0000%	0.0000%
Trent	0.0000%	0.0000%	0.0000%

Weighted Average	**0.6724%**	**0.7282%**	**0.7310%**

c) Please describe any steps that are contemplated to decrease the loss factor in the PDI service area during the test year (2009) and/or during a longer planning period.

Response:

PDI will continue to purchase low loss design transformers (higher capital cost but lower overall operating cost). Transformer peak loading is reviewed prior to replacement to optimize capacity to load (reduce transformer losses). PDI will rebuild and re-conductor to larger wire size where possible (reduce line losses.). PDI will convert voltages from 4.16 kV to 27.6 kV to reduce line losses and substation transformer losses. PDI will conduct periodic grid system studies to optimize line losses, and periodic reviews of feeder loads to balance between three phases to reduce line loss and reduce ground current returns and losses. Smart meters may assist in the reduction of losses from theft.

37. Taxes / PILs – Ref: Exhibit 4 / Tab 3 / Schedule 1

Please provide a revised Table 1 – Tax Calculations including 2006 actual and 2007 actual year calculations in addition to 2006 Board-approved, 2008 bridge and 2009 test years.

Response:

Please see Attachment “C” accompanying these responses.

38. Taxes / PILs – Ref: Exhibit 4 / Tab 3 / Schedule 1

Please explain the adjustments to rate base of $7,587,642 for 2008 bridge and $11,443,278 for 2009 test years shown in the calculation of the Ontario Capital tax allowance.

Response:

The adjustments to rate base of $7,587,642 and $11,443,278 are in fact not adjustments to rate base but the reconciliation of rate base for regulatory purposes to taxable capital used for the calculation of Ontario Capital Tax. The following table outlines the calculation of Ontario Taxable Capital for purposes of the Ontario Capital Tax calculation. The reconciliation of that taxable capital calculation to rate base and the "adjustments" reflected in the Application are provided below.

Ontario Taxable Capital Calculation

Balance Sheet

	Reference	Acct	2008 (Thousand $'s)	2009 (Thousand $'s)
Shareholder's Equity	1	1850	26,203	25,910
Long-Term Debt	1	1800	23,157	23,157
Non-Current Liabilities	1	1650	7,559	11,027
Current Portion of Customer Deposits	1	2210	720	727
			57,639	60,821

Adjustment for NBV/UCC

	Reference	Acct	2008	2009
UCC	2	-	50,046	51,657
		NBV		
Distribution Plant	1	1450	76,001	81,502
General Plant	1	1500	(7,591)	(8,849)
Other Capital	1	1550	2,098	2,098
Accumulated Amortization	1	1600	(24,076)	(27,616)
			46,432	47,135
Less: Land	1	1805	(135)	(135)
			46,297	47,000
Net UCC/NBV Difference			3,749	4,657
Total Taxable Capital for Ontario Capital Tax			**61,388**	**65,478**
Rate Base	3		53,571	54,118
Difference Between Rate Base and Taxable Capital	-		7,817	11,360
Difference Reflected as Adjustment	3		(7,587)	(11,443)
Difference - Immaterial			230	(83)

Reference

1. Per Exhibit 1, Tab 3, Schedule 2, Appendices A and B
2. Per Exhibit 4, Tab 3, Schedule 2
3. Per Exhibit 4, Tab 3, Schedule 1, Page 2 of 3

Exhibit 5 – Deferral and Variance Accounts

39. Deferral/Variance Accounts:
References:
i. Exhibit 5 / Tab 1 / Schedule 1, page 1
ii. Exhibit 5 / Tab 1 / Schedule 2, pages 1-2

- The 1st reference provides a description of deferral and variance accounts.
- The 2nd reference provides information on methods of disposition of accounts.

a) Please list and provide a brief description of all PDI's deferral and variance accounts that have account balances as of December 31, 2007.

Response:

Please see the following table:

Regulatory Asset Account Balances
at December 31, 2007

Account Description	Account #	Principal	Interest	Total
Other Regulatory Assets - OEB Cost Assessments	1508	$74,235	$7,270	$81,505
RSVA - One-time Wholesale Market Service	1582	$43,362	$6,367	$49,729
Smart Meter Capital and Recovery Offset	1555	$503,172	$15,096	$518,268
Deferred Payments in Lieu of Taxes	1562	($849,995)	($186,848)	($1,036,843)
Deferred PILs Contra Account	1563	$849,995	$186,848	$1,036,843
CDM Expenditures and Recoveries	1565	$23,108	$904	$24,012
CDM Contra Account	1566	($23,108)	($904)	($24,012)
Recovery of Regulatory Asset Balances	1590	($1,145,930)	$1,415,783	$269,853
Low Voltage Variance Account	1550	($356,965)	($13,566)	($370,531)
RSVA - Wholesale Market Service Charge	1580	($1,601,646)	($1,478)	($1,603,124)
RSVA - Retail Transmission Network Charge	1584	($172,685)	($9,735)	($182,420)
RSVA - Retail Transmission Connection Charge	1586	($317,190)	($77,962)	($395,152)
RSVA Power (including Global Adjustment)	1588	$628,467	$423,720	$1,052,187
RSVA Power - Sub-account Global Adjustment	1588	$628,467	$4,214	$632,681

b) PDI is requesting the disposition of regulatory deferral and variance accounts 1508 and 1550. Please provide the information shown in the attached continuity schedule (in excel format) for each of the regulatory accounts requested for disposition in rates. Please note that it is optional to forecast the principal balances beyond 2007 and the accrued interest on these forecasted balances in the attached continuity schedule.

Response:

Please see Attachment "D" to these responses.

c) Please provide the interest rates that were used to calculate the carrying charges for each regulatory deferral and variance account for the period from January 1, 2005 to the date prior to disposition in rates (i.e. April 30, 2009).

Response:

Please see the following table:

Interest Rates

2005	January - December	7.25%
2006	January - April	7.25%
2006	May - June	4.14%
2006	July - December	4.59%
2007	January - September	4.59%
2007	October - December	5.14%
2008	January December	3.35%
2009	January – April	3.35%

d) The spreadsheet provides a sub-total for the accounts: 1508, 1518, 1525, 1548, 1570, 1571, 1572, 1574, 1582, 1592, and 2425.

- Please calculate a set of rate riders that would dispose of the net balance of these accounts (excluding account 1592), and specify how many years the rate rider is assumed to be in effect. Please identify whether the balances are taken at the end of 2007, or at some other time.

- Please also provide details of how the individual balances would be allocated to customer classes, where possible using updated values of the same allocators as were used for the respective accounts in the 2006 model for regulatory asset recovery rate riders.

Response:

The rate rider is assumed to be in effect for three years and is applied to the deferral account balances at December 31, 2007 with interest estimated from that date to April 30, 2009 at 3.35%.

Table 1 – Allocators and Billing Determinants used in Table 2 and Table 3

2007 Data By Class	kW	kWhs	Cust. Num.'s	Number of Metered Customers	Dx Revenue
RESIDENTIAL CLASS		286,683,602			$ 7,493,048
GENERAL SERVICE <50 KW CLASS		125,727,009			$ 2,041,564
GENERAL SERVICE >50 KW NON TIME OF USE	830,730	334,460,762			$ 2,506,566
GENERAL SERVICE >50 KW TIME OF USE					
STANDBY					
LARGE USER CLASS	128,682	63,221,100			$ 98,177
UNMETERED & SCATTERED LOADS		2,211,753			$ 18,873
SENTINEL LIGHTS	2,574	1,308,319			$ 15,288
STREET LIGHTING	16,613	6,588,942			$ 101,228
Totals	978,599	820,201,487	-	-	$ 12,274,744

Allocators	kW	kWhs	Cust. Num.'s	Number of Metered Customers	Dx Revenue
RESIDENTIAL CLASS	0.0%	35.0%			61.0%
GENERAL SERVICE <50 KW CLASS	0.0%	15.3%			16.6%
GENERAL SERVICE >50 KW NON TIME OF USE	84.9%	40.8%			20.4%
GENERAL SERVICE >50 KW TIME OF USE	0.0%	0.0%			0.0%
STANDBY	0.0%	0.0%			0.0%
LARGE USER CLASS	13.1%	7.7%			0.8%
UNMETERED & SCATTERED LOADS	0.0%	0.3%			0.2%
SENTINEL LIGHTS	0.3%	0.2%			0.1%
STREET LIGHTING	1.7%	0.8%			0.8%
Totals	100%	100%	0%	0%	100%

Table 2 – Method of Disposition of Accounts and Rate Riders

Deferral and Variance Accounts:		Amount	ALLOCATOR	Residential	GS < 50 KW	GS > 50 Non TOU	Large Users	Small Scattered Load	Sentinel Lighting	Street Lighting	Total
One-Time WMSC - Account 1582		$ 51,666	kWh	$ 18,059	$ 7,920	$ 21,068	$ 3,982	$ 139	$ 82	$ 415	$ 51,666
Other Regulatory Assets - Account 1508		$ 84,821	Dx Revenue	$ 51,778	$ 14,108	$ 17,321	$ 678	$ 130	$ 106	$ 700	$ 84,821
Total to be Recovered		$ 136,487		$ 69,837	$ 22,027	$ 38,389	$ 4,661	$ 270	$ 188	$ 1,115	$ 136,487
Balance to be collected or refunded, Variable		$ 136,487		$ 69,837	$ 22,027	$ 38,389	$ 4,661	$ 270	$ 188	$ 1,115	$ 136,487
Number of years for Variable	3										
Balance to be collected or refunded per year, Variable		$ 45,496		$ 23,279	$ 7,342	$ 12,796	$ 1,554	$ 90	$ 63	$ 372	$ 45,496

Class	Residential	GS < 50 KW	GS > 50 Non TOU	Large Users	Scattered Load	Sentinel Lighting	Street Lighting
Deferral and Variance Account Rate Riders, Variable	$ 0.0001	$ 0.0001	$ 0.0154	$ 0.0121	$ 0.0000	$ 0.0244	$ 0.0224
Billing Determinants	kWh	kWh	kW	kW	kWh	kW	kW

e) Please provide a table and explanatory notes similar to part d., assuming that all deferral and variance accounts would be cleared, except Accounts 1555, 1556, 1562,1563,1565,1566,1590 and 1592.

Response:

Table 1 – Allocators and Billing Determinants used in Table 2 and Table 3

2007 Data By Class	kW	kWhs	Cust. Num.'s	Number of Metered Customers	Dx Revenue
RESIDENTIAL CLASS		286,683,602			$ 7,493,048
GENERAL SERVICE <50 KW CLASS		125,727,009			$ 2,041,564
GENERAL SERVICE >50 KW NON TIME OF USE	830,730	334,460,762			$ 2,506,566
GENERAL SERVICE >50 KW TIME OF USE					
STANDBY					
LARGE USER CLASS	128,682	63,221,100			$ 98,177
UNMETERED & SCATTERED LOADS		2,211,753			$ 18,873
SENTINEL LIGHTS	2,574	1,308,319			$ 15,288
STREET LIGHTING	16,613	6,588,942			$ 101,228
Totals	978,599	820,201,487	-	-	$ 12,274,744

Allocators	kW	kWhs	Cust. Num.'s	Number of Metered Customers	Dx Revenue
RESIDENTIAL CLASS	0.0%	35.0%			61.0%
GENERAL SERVICE <50 KW CLASS	0.0%	15.3%			16.6%
GENERAL SERVICE >50 KW NON TIME OF USE	84.9%	40.8%			20.4%
GENERAL SERVICE >50 KW TIME OF USE	0.0%	0.0%			0.0%
STANDBY	0.0%	0.0%			0.0%
LARGE USER CLASS	13.1%	7.7%			0.8%
UNMETERED & SCATTERED LOADS	0.0%	0.3%			0.2%
SENTINEL LIGHTS	0.3%	0.2%			0.1%
STREET LIGHTING	1.7%	0.8%			0.8%
Totals	100%	100%	0%	0%	100%

Table 3 – Method of Disposition of Accounts and Rate Riders

Deferral and Variance Accounts:	Amount	ALLOCATOR	Residential	GS < 50 KW	GS > 50 Non TOU	Large Users	Small Scattered Load	Sentinel Lighting	Street Lighting	Total
WMSC - Account 1580	$ (1,674,664)	kWh	$ (585,342)	$ (256,706)	$ (682,892)	$ (129,083)	$ (4,516)	$ (2,671)	$ (13,453)	$ (1,674,664)
One-Time WMSC - Account 1582	$ 51,666	kWh	$ 18,059	$ 7,920	$ 21,068	$ 3,982	$ 139	$ 82	$ 415	$ 51,666
Network - Account 1584	$ (190,133)	kWh	$ (66,457)	$ (29,145)	$ (77,532)	$ (14,655)	$ (513)	$ (303)	$ (1,527)	$ (190,133)
Connection - Account 1586	$ (409,320)	kWh	$ (143,069)	$ (62,744)	$ (166,912)	$ (31,550)	$ (1,104)	$ (653)	$ (3,288)	$ (409,320)
Power - Account 1588	$ 1,080,259	kWh	$ 377,581	$ 165,591	$ 440,507	$ 83,266	$ 2,913	$ 1,723	$ 8,678	$ 1,080,259
Subtotal - RSVA	$ (1,142,192)		$ (399,228)	$ (175,084)	$ (465,762)	$ (88,040)	$ (3,080)	$ (1,822)	$ (9,176)	$ (1,142,192)
Other Regulatory Assets - Account 1508	$ 84,821	Dx Revenue	$ 51,778	$ 14,108	$ 17,321	$ 678	$ 130	$ 106	$ 700	$ 84,821
Low Voltage - Account 1550	$ (386,475)	kWh	$ (135,084)	$ (59,242)	$ (157,596)	$ (29,789)	$ (1,042)	$ (616)	$ (3,105)	$ (386,475)
Subtotal - Non RSVA, Variable	$ (301,654)		$ (83,305)	$ (45,134)	$ (140,275)	$ (29,111)	$ (912)	$ (511)	$ (2,405)	$ (301,654)
Total to be Recovered	$ (1,443,846)		$ (482,534)	$ (220,219)	$ (606,037)	$ (117,151)	$ (3,992)	$ (2,333)	$ (11,581)	$ (1,443,846)

		Amount	Residential	GS < 50 KW	GS > 50 Non TOU	Large Users	Small Scattered Load	Sentinel Lighting	Street Lighting	Total
Balance to be collected or refunded, Variable		$ (1,443,846)	$ (482,534)	$ (220,219)	$ (606,037)	$ (117,151)	$ (3,992)	$ (2,333)	$ (11,581)	$ (1,443,846)
Number of years for Variable	3									
Balance to be collected or refunded per year, Variable		$ (481,282)	$ (160,845)	$ (73,406)	$ (202,012)	$ (39,050)	$ (1,331)	$ (778)	$ (3,860)	$ (481,282)

Class	Residential	GS < 50 KW	GS > 50 Non TOU	Large Users	Scattered Load	Sentinel Lighting	Street Lighting
Deferral and Variance Account Rate Riders, Variable	$ (0.0006)	$ (0.0006)	$ (0.2432)	$ (0.3035)	$ (0.0006)	$ (0.3021)	$ (0.2324)
Billing Determinants	kWh	kWh	kW	kW	kWh	kW	kW

f) The Accounting Procedures Handbook in article 220 states that the distributor shall stop recording amounts (except for carrying charges) in account 1508 sub-account OEB Cost Assessments and sub-account OMERS after April 30, 2006.

- Why is PDI accruing and/or adjusting balances beyond April 30, 2006 in these sub-accounts?
- What would the balance be in both sub-accounts if principal accruals ceased at April 30, 2006?

Response:

PDI does not have a balance in sub-account OMERS. Carrying charges have been accrued in sub-account OEB Cost Assessments since April 30, 2006. There have not been any accruals or adjustments to the principal balance since this date.

Exhibit 6 – Cost of Capital and Rate of Return

40. Long Term Debt – Ref: Exhibit 6 / Tab 1 / Schedule 1 and Exhibit 1 / Tab 3 / Schedule 1 / Appendix A

In Exhibit 6 / Tab 1 / Schedule 1, under "Cost of Debt: Long Term", PDI documents that it has two long-term debt instruments, consisting of a Long Term Loan with a principal of $21,657,680, and a Demand Loan of $1,500,000 with City of Peterborough. Board staff has summarized these debt instruments and the documented rates in the following table:

Long-term Debt

	Amount	Rate
Long-term Loan with City of Peterborough	$ 21,657,680	6.10%
Demand Loan	$ 1,500,000	4.85%
		6.02%

Further documentation on these loans are contained in Note 6 of PDI's 2006 Audited Financial Statements and Note 7 of the 2007 Audited Financial Statements (both in Exhibit 1 / Tab 3 / Schedule 1 / Appendix B). The Notes to the Audited Financial Statements state that the debt of $21,657,680 had a rate of 7.25% to April 30, 2006 and 6.25% thereafter. Further, the demand loan of $1,500,000 attracts a rate of bank prime less 1.25%. It states that there are no specific terms for repayment of either of the demand loans.

a) Please provide copies of each of these loan documents. In addition, please state the starting date and term to maturity of each of these loans.

Response:

The long-term loan payable to the City of Peterborough Holdings Inc., in the amount of $21,657.680, was established January 1, 2000 and the initial interest rate was 6% per annum. In the time available for the preparation of responses to these interrogatories, PDI has been unable to locate the original promissory note. However, other than the interest rate, the terms have not been amended since that date and are properly described in the Corporation's audited financial statements. The note is payable on demand and is without specified maturity date or repayment terms. Since the initial origination date of the debt, it has been mutually agreed by the lender and the Corporation that interest rate on this debt would be amended to reflect the long-term debt rate as prescribed by the Ontario Energy Board.

With respect to the demand loans in the amount of $1,500,000, PDI is enclosing copies of the promissory notes, which indicate the starting date and terms that are described in the audited financial statements, as Attachment "E" to these responses.

b) Please describe PDI's basis for proposing a rate of 6.10% for the Demand Loan due to the City of Peterborough Holdings Inc. with a principal of $21,657,680. Please support PDI's basis with respect to the policy guidelines for long-term debt rates as documented in section 2.2.1 of the Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors, issued December 20, 2006.

Response:

Section 2.2.1 of the Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors, issued December 20, 2006 states that for all variable-rate debt and for all affiliate debt that is callable on demand the Board will use the current deemed long-term debt rate.

The debt rate of 6.10% reflects the cost of capital parameter update for the 2008 cost of service application issued by the OEB on March 7, 2008.

c) Please confirm the current rate due on the Demand Loan of $1,500,000 and how frequently this rate is updated.

Response:

The current rate due on the demand loan is bank prime less 1.25% and it is updated monthly.

d) Please confirm that PDI does not currently, nor does it plan to acquire in 2009, additional affiliated or third-party debt.

Response:

PDI incurred additional third-party debt in December of 2008.

e) If PDI does plan on acquiring new debt, with due to an affiliated or third-party, please provide information on the reason for the debt, the forecasted principal, interest rate and term.

Response:

PDI has arranged a $6.6 million ten year credit facility with the Toronto Dominion Bank at a rate of 4.55% to address the Corporation's Smart Meter and general capital requirements.

Exhibit 8 – Cost Allocation; Exhibit 9 - Rate Design

41. Cost Allocation & Rate Design:
References:

- **i. Exhibit 8 / Tab 1 / Schedule 2, pages 3 to 4**
- **ii. Exhibit 8 / Tab 1 / Schedule 2 / Appendix A, Sheet O1**
- **iii. Exhibit 8 / Tab 1 / Schedule 2 / Appendix A, Sheet O2**
- **iv. Exhibit 9 / Tab 1 / Schedule 1, page 1**
- **v. Exhibit 9 / Tab 1 / Schedule 9 / Appendix A**
- **vi. Exhibit 9 / Tab 1 / Schedule 5, pages 1 to 7**
- **vii. Exhibit 9 / Tab 1 / Schedule 7, pages 1 to 3**
- **viii. Exhibit 9 / Tab 1 / Schedule 1, page 3**

- The 1st reference provides amended cost allocation informational filing and proposed (2009) revenue-to-cost ratios.
- The 2nd reference provides amended cost allocation informational filing revenue requirement and revenue-to-cost ratios.
- The 3rd reference provides amended cost allocation informational filing Customer Unit Cost per month – Avoided Cost and Customer Unit Cost per month – Minimum System.
- The 4th reference provides the base revenue requirement for 2009.
- The 5th reference provides bill impact calculations.
- The 6th reference provides the existing rate schedule.
- The 7th reference provides the proposed (2009) rate schedule.
- The 8th reference provides information on fixed/variable revenue proportions.

a) Please refer to the following table. With respect to the monthly service charge for the USL rate class:

	Monthly Service Charge (5th reference)				
	Peterborough Service Area - 2008	Lakefield Service Area - 2008	Asphodel-Norwood Service Area - 2008	Harmonized – 2009	Minimum System Cost (3rd reference)
USL	$26.15	$28.71	$20.22	$292.53	$7.58

- Please explain the reason for the significant increase in the monthly service charge from 2008 to 2009.

Response:

The cost allocation study suggested the revenue to cost ratio for USL is 7.13%. In order to move this revenue to cost ratio half way to the target minimum of 80%, as prescribed by the Board, the USL revenue to cost ratio must move to 43.57%. In order to make this movement the revenue assigned to the USL class will be around $180k. Currently the USL pays about $16.5k in distribution revenue. This means revenues to USL will increase by almost 11 times. Under the assumption that the fixed/variable split remains the same, which was accepted by the Board for many 2008 applicants, a Monthly Service Charge of $292.53 is reasonable considering the 2008 weighted average Monthly Service Charge of the three service areas is $27.17.

The Minimum System with PLCC Adjustment of $7.58 per month from the Cost Allocation Study is on a per connection basis, and not on a per customer basis. However, PDI charges the Monthly Service Charge for the USL class on a per customer basis and in 2004 PDI had 10 USL customers. In the Cost Allocation Study PDI assumed there were 4,159 USL connections. These means the cost associated with the $7.58 is $7.58 times 4,159 times 12 or $378,302. If this amount was collected from 10 customers it would be $3,152.52 per month which helps explain the increase in the 2009 USL Monthly Service Charge. If the USL rate class was at a 100% revenue to cost ratio the Cost Allocation Study suggest the Monthly Service Charge per customer should be $3,152.52.

- The existing monthly service charge for the Asphodel-Norwood and Lakefield Service Areas are provided on a per customer basis (6^{th} reference), whereas both the existing service charge for the Peterborough Service Area and the proposed (2009) harmonized service charge do not explicitly state they are on a per customer basis (6^{th} and 7^{th} references).
    - o Please explain the reason for this inconsistency.

Response:

In all cases the Monthly Service Charge for USL should be shown on a per customer basis. For those cases that it is not shown on a per customer basis, this is a typographical error.

- o Please provide the average, lowest and highest number of connections per customer.

Response:

Total Number of Customers	10
Average Number of Connections	419
Lowest Number of Connections	1
Highest Number of Connections	4,104

- Please explain the reason for the Monthly Service Charge proposed for 2009 being significantly higher than the Customer Unit Cost per month – Minimum System.

Response:

The proposed USL Monthly Service Charge is consistent with the evidence outlined in Exhibit 9 / Tab 1 / Schedule 1, page 3 and 4 which states:

In its 2008 electricity distribution rate application, Norfolk Power Distribution Inc. "proposed distribution rates that maintain the existing fixed/variable split for the main customer classes", and submitted that the OEB had not established a ceiling for monthly service charges [see page 28 of the OEB's May 26, 2008 Decision in the Norfolk Power Distribution Inc. 2008 Distribution Rate Application (EB-2007-0753)]. In accepting Norfolk Power's proposal, the OEB held (also at page 28)

> "The Board has convened a consultation with the industry and stakeholders respecting many aspects of rate design, including the fixed/variable split. (EB-2007-0031). The relationship between the fixed and variable portions of the customer bill has important implications for ratemaking, and the magnitude of the fixed charge has benefits and9 drawbacks for various stakeholders.
>
> In light of the consultation initiated by the Board on these subjects it would be inappropriate to attempt to predict its outcome and to impose a new structure on the Applicant. Accordingly the Board accepts the Applicant's proposal."

PDI submits that it is also appropriate for the purposes of setting rates in this Application to maintain the current fixed and variable proportions of its rates. PDI confirms that it is making no changes to the fixed/variable proportions of its rates. Any changes in PDI's MSCs are due solely to changes in the total base revenue requirement attributable to each customer class. PDI's approach is therefore consistent with the approach approved by the OEB in its Norfolk Power Decision.

b) Please refer to the following below. With respect to the Large Use rate class, the change in the monthly charge and volumetric rate from the current to the proposed rate schedule is respectively 86% and 79%.

> Please reconcile this unequal change in the fixed and variable components of revenue with the statement that PDI is maintaining the same fixed/variable revenue proportions assumed in the current rates to all customer classifications (8th reference).

	6th and 7th references	
Large Use	Monthly Charge	Volumetric Rate
Current	$4493.94	$0.9502
Proposed (2009)	$3869.28	$0.7526
Change – Current to Proposed	86% decrease	79% decrease

Response:

The changes in the fixed and variable components of revenue are equal when the low voltage charges are removed from the volumetric charge – PDI submits that this is the appropriate approach to comparing current and proposed fixed and variable components.

The table below reflects the change excluding the low voltage charges

Large Use	Monthly Charge	Volumetric Rate
Current LV Charge Comp Current (Net)	$4493.94	$0.9502 ($0.4252) $0.5250
Proposed (2009) LV Charge Comp Proposed (Net)	$3869.28	$0.7526 ($0.3006) $0.4520
Change – Current to Proposed (Net)	86% decrease	86% decrease

c) Please file an electronic copy of Run 2 of the Amended Cost Allocation Informational Filing to be a part of the record of this application.

Response:

An electronic copy of the requested run is being filed with the electronic version of these responses. It has been referred to as Attachment “F” in the index to these responses.

42. Specific Service Charges – Ref: Exhibit 1 / Tab 1 / Schedule 2 / Appendix A, pages 2-3

Please confirm that the proposed specific services charges as shown in the referenced evidence are identical to standard charges in Schedule 11-3 of the 2006 EDR Handbook.

Response:

Yes, the charges shown are identical to the standard charges in Schedule 11-3 of the 2006 EDR Handbook.

43. Retail Transmission Rate:
References:
 i. Exhibit 9 / Tab 1 / Schedule 3, pages 1-2
 ii. Guideline – Electricity Distribution Retail Transmission Service Rates (G-2008-0001)

- The 1st reference states that PDI is proposing to harmonize retail transmission rates based upon the weighted average of the current Board Approved Retail Transmission Rates for Asphodel-Norwood, Lakefield and Peterborough Service Areas.
- The 2nd reference provides electricity distributors with instructions on the evidence needed, and the process to be used, to adjust retail transmission service rates to reflect changes in the Ontario Uniform Transmission Rates.

On August 28, 2008, the Board issued its Decision and Rate Order in proceeding EB-2008-0113, setting new Uniform Transmission Rates (UTR) for Ontario transmitters, effective January 1, 2009. The change in the UTRs affects the retail transmission service rates (RTSR) charged by distributors. Given that PDI is partially embedded within Hydro One Distribution, its wholesale cost of transmission service is affected by the approved UTRs change.

On October 22, 2008, the Board issued its Guideline on Electricity Distribution Retail Transmission Service Rates, outlining the evidence it expects distributors to file in support of their cost of service applications.

PDI is expected to file an update to that application detailing the calculations for adjusting its RTSRs.

a) Please file a variance analysis using 2 years of actual data examining what, if any, trend is apparent in the monthly balances in the RTSR deferral accounts

Response:

Retail Transmission Service Rate Deferral Accounts
Principal Balances

		2006 Q1	2006 Q2	2006 Q3	2006 Q4
RSVA - Retail Transmission Network Charge	1584	$126,466	$23,422	$97,518	($90,942)
RSVA - Retail Transmission Connection Charge	1586	($2,362,173)	($892,883)	($778,892)	($836,334)

		2007 Q1	2007 Q2	2007 Q3	2007 Q4
RSVA - Retail Transmission Network Charge	1584	($549,339)	($327,935)	($151,671)	($172,685)
RSVA - Retail Transmission Connection Charge	1586	($950,621)	($717,288)	($491,551)	($317,190)

b) Please file a calculation of the proposed RTSR rates that includes the adjustment of the UTRs effective January 1, 2009 and an adjustment to eliminate ongoing trends in the balances in the RTSR deferral accounts

Response:

PDI has not identified any ongoing trends that need to be addressed, and as such is recommending that PDI follow Guideline G-2008-0001 - Electricity Distribution Retail Transmission Service Rates. Based on that Guideline:

- The Network Service Rate has increased from $2.31 to $2.57 per kW per month, an 11.3 % increase;
- The Line Connection Service Rate has increased from $0.59 to $0.70 per kW per month, an 18.6% increase;
- The Transformation Connection Service Rate has increased from $1.61 to $1.62 per kW per month, a 0.6% increase; and
- Based upon this PDI recommends increasing the proposed harmonized retail transmission network rates by 11.3% and the proposed harmonized retail transmission connection rates by 5.5% (i.e. (0.70+1.62) / (0.59 +1.61) = 1.055)

Retail Service Transmission Rates

Proposed Increase:

Network	**11.30%**
Connection	**5.50%**

	Harmonized Rate per Rate Application	Revised Harmonized Rate
Residential		
Network	$0.0050	$0.0056
Connection	$0.0032	$0.0033
GS < 50 kW		
Network	$0.0046	$0.0051
Connection	$0.0029	$0.0030
GS > 50 kW		
Network	$1.8637	$2.0743
Connection	$1.1321	$1.1944
Network - Interval Metered	$1.9244	$2.1419
Connection - Interval Metered	$1.6564	$1.7475
Network - Interval Metered >1000 kW	$1.7799	$1.9810

Connection - Interval Metered > 1000 kW	$1.5015	$1.5841
Large Use		
Network	$2.1958	$2.4439
Connection	$1.3869	$1.4632
Sentinel Lights		
Network	$1.4153	$1.5752
Connection	$0.8989	$0.9484
Street Lighting		
Network	$1.4047	$1.5635
Connection	$0.8780	$0.9263
USL		
Network	$0.0046	$0.0051
Connection	$0.0029	$0.0030

44. Rural or Remote Electricity Rate Protection ("RRRP")

By letter dated December 17, 2008, the Board informed the electricity distributors of the approval it has given to the IESO regarding the level of charge the IESO may apply to its Market Participants for the Rural or Remote Electricity Rate Protection (RRRP) program. In that letter, the Board stated: "Distributors that currently have a rate application before the Board shall file this letter as an update to their evidence along with a request that the RRRP charge in their tariff sheet be revised to 0.13 cents per kilowatt-hour effective May 1, 2009."

If PDI has not done so, please file the required addition to the evidence as outlined in the December 17th letter.

Response:

Further to the Board's direction in its letter of December 17th, a copy of that letter is enclosed as Attachment "G" to these responses. In light of the Board's decision with respect to the level of the charge the IESO may apply to its Market Participants for the RRRP program, PDI hereby requests that the Board revise PDI's RRRP charge from the 0.10 cents per kilowatt hour currently shown in PDI's proposed Schedule of Rates and Charges to 0.13 cents per kilowatt-hour effective May 1, 2009. PDI will make this change in its Draft Rate Order to be filed following the Board's Decision on this Application.

ATTACHMENT A

REFERENCE: BOARD STAFF QUESTION 18

Feed into OEB Cost Allocation Model sheet "I6 Customer Data", row 56

ID	Total	Residential	GS>50kW	Street Lighting	GS<50	USL	Large User	Sentinel Lighting
		1	2	3	4	5	6	7
kWh - 30 year weather normalized amount	840,137,722	303,594,227	330,877,467	6,312,677	130,550,090	2,529,936	65,153,441	1,119,884

Feed into OEB Cost Allocation Model sheet "I8 Demand Data", row 40, 45, 50, 55, 61 and 67

Customer Classes		Total	Residential	GS>50kW	Street Lighting	GS<50	USL	Large User	Sentinel Lighting
			1	2	3	4	5	6	7
CO-INCIDENT PEAK (kW)									
1 CP									
Total Sytem CP	DCP1	148,677	52,385	55,752	0	30,209	0	10,331	0
4 CP									
Total Sytem CP	DCP4	568,716	220,090	210,894	1,865	97,774	643	37,129	322
12 CP									
Total Sytem CP	DCP12	1,557,928	589,038	584,222	7,618	266,384	2,872	106,451	1,343
NON CO_INCIDENT PEAK (kW)									
1 NCP									
Classification NCP from Load Data Provider	DNCP1	185,488	76,393	59,057	2,954	33,754	1,089	11,724	517
4 NCP									
Classification NCP from Load Data Provider	DNCP4	706,087	290,674	229,815	7,523	128,857	3,269	44,624	1,325
12 NCP									
Classification NCP from Load Data Provider	DNCP12	1,850,595	715,147	639,673	19,219	339,189	7,846	126,107	3,413

ATTACHMENT B

REFERENCE: BOARD STAFF QUESTION 23(a) (vi)

Table 2.2 - Actual and Weather Corrected Weekly Energy Demand

Week Ending	Actual Energy (GWh)	Weather Corrected Energy (GWh)	Weather Correction (GWh)	Week Number	Notes for Week
5-May-02	2,701	2,653	-47	18	
12-May-02	2,670	2,632	-38	19	
19-May-02	2,680	2,585	-95	20	
26-May-02	2,598	2,571	-27	21	Victoria Day
2-Jun-02	2,746	2,703	-43	22	
9-Jun-02	2,686	2,675	-11	23	
16-Jun-02	2,784	2,852	68	24	
23-Jun-02	2,890	2,811	-79	25	
30-Jun-02	3,113	2,944	-169	26	
7-Jul-02	3,189	2,904	-285	27	Canada Day
14-Jul-02	2,998	2,991	-8	28	
21-Jul-02	3,269	3,174	-95	29	
28-Jul-02	3,079	3,031	-48	30	
4-Aug-02	3,348	3,048	-300	31	
11-Aug-02	2,946	2,944	-2	32	Civic Holiday
18-Aug-02	3,438	3,117	-321	33	
25-Aug-02	2,949	2,940	-10	34	
1-Sep-02	2,952	2,924	-28	35	
8-Sep-02	3,017	2,826	-191	36	Labour Day
15-Sep-02	3,050	2,869	-181	37	All-Time September Peak
22-Sep-02	2,986	2,830	-156	38	
29-Sep-02	2,742	2,749	7	39	
6-Oct-02	2,812	2,776	-36	40	All-Time October Peak
13-Oct-02	2,715	2,757	42	41	
20-Oct-02	2,725	2,671	-55	42	Thanksgiving
27-Oct-02	2,856	2,784	-72	43	
3-Nov-02	2,921	2,769	-152	44	
10-Nov-02	2,898	2,903	5	45	
17-Nov-02	2,935	2,925	-10	46	Rememberance Day
24-Nov-02	2,960	2,979	19	47	
1-Dec-02	3,066	2,980	-86	48	
8-Dec-02	3,219	3,133	-86	49	
15-Dec-02	3,142	3,185	43	50	
22-Dec-02	3,128	3,137	9	51	
29-Dec-02	2,768	2,796	28	52	Christmas & Boxing Day
	102,974	100,568	97.66%		

5-Jan-03	2,911	2,952	41	1	New Years Day
12-Jan-03	3,163	3,174	11	2	
19-Jan-03	3,338	3,261	-78	3	
26-Jan-03	3,435	3,275	-160	4	
2-Feb-03	3,270	3,268	-2	5	
9-Feb-03	3,250	3,251	1	6	
16-Feb-03	3,437	3,210	-227	7	All-Time February Peak
23-Feb-03	3,207	3,193	-15	8	
2-Mar-03	3,254	3,136	-118	9	
9-Mar-03	3,249	3,090	-159	10	All-Time March Peak
16-Mar-03	3,113	3,038	-75	11	
23-Mar-03	2,907	3,020	113	12	
30-Mar-03	2,851	2,904	53	13	
6-Apr-03	3,058	2,904	-153	14	All-Time April Peak
13-Apr-03	2,903	2,834	-69	15	
20-Apr-03	2,688	2,716	28	16	Good Friday
27-Apr-03	2,718	2,687	-31	17	Easter Monday
4-May-03	2,656	2,683	27	18	
11-May-03	2,659	2,705	45	19	
18-May-03	2,625	2,641	17	20	
25-May-03	2,562	2,571	9	21	Victoria Day
1-Jun-03	2,638	2,666	29	22	
8-Jun-03	2,654	2,670	16	23	
15-Jun-03	2,676	2,730	54	24	
22-Jun-03	2,749	2,794	45	25	
29-Jun-03	3,088	2,870	-218	26	
6-Jul-03	2,993	2,814	-179	27	Canada Day
13-Jul-03	2,846	2,878	32	28	
20-Jul-03	2,843	2,980	137	29	

27-Jul-03	2,883	2,882	-1	30	
3-Aug-03	2,893	2,886	-7	31	
10-Aug-03	3,015	2,862	-153	32	Civic Holiday
17-Aug-03	2,723	2,605	-118	33	Blackout
24-Aug-03	2,749	2,625	-124	34	Conservation Appeals
31-Aug-03	2,845	2,829	-17	35	
7-Sep-03	2,689	2,722	33	36	Labour Day
14-Sep-03	2,868	2,762	-107	37	
21-Sep-03	2,772	2,772	1	38	
28-Sep-03	2,679	2,698	19	39	
5-Oct-03	2,731	2,661	-71	40	
12-Oct-03	2,695	2,737	42	41	
19-Oct-03	2,667	2,655	-12	42	Thanksgiving
26-Oct-03	2,794	2,766	-28	43	
2-Nov-03	2,796	2,829	33	44	
9-Nov-03	2,891	2,833	-59	45	
16-Nov-03	2,918	2,932	14	46	Rememberance Day
23-Nov-03	2,871	3,035	165	47	
30-Nov-03	2,973	3,021	48	48	
7-Dec-03	3,146	3,120	-26	49	
14-Dec-03	3,162	3,150	-12	50	
21-Dec-03	3,135	3,138	3	51	
28-Dec-03	2,703	2,873	170	52	Christmas & Boxing Day
	151,341	150,310	99.32%		

4-Jan-04	2,707	2,886	178	1	New Years Day
11-Jan-04	3,369	3,217	-152	2	
18-Jan-04	3,445	3,331	-113	3	All-Time January Peak
25-Jan-04	3,446	3,285	-161	4	
1-Feb-04	3,419	3,309	-110	5	
8-Feb-04	3,239	3,271	32	6	
15-Feb-04	3,215	3,203	-13	7	
22-Feb-04	3,158	3,157	-1	8	
29-Feb-04	3,039	3,126	87	9	
7-Mar-04	2,961	3,107	147	10	
14-Mar-04	3,027	3,027	0	11	
21-Mar-04	3,069	2,982	-88	12	
28-Mar-04	2,921	2,940	18	13	
4-Apr-04	2,847	2,871	24	14	
11-Apr-04	2,746	2,675	-71	15	Good Friday
18-Apr-04	2,741	2,754	13	16	Easter Monday
25-Apr-04	2,692	2,706	14	17	
2-May-04	2,726	2,719	-7	18	
9-May-04	2,706	2,659	-47	19	
16-May-04	2,746	2,704	-42	20	All-Time May Peak
23-May-04	2,670	2,678	8	21	
30-May-04	2,607	2,648	41	22	Victoria Day
6-Jun-04	2,661	2,691	30	23	
13-Jun-04	2,893	2,821	-72	24	
20-Jun-04	2,894	2,877	-17	25	
27-Jun-04	2,774	2,926	152	26	
4-Jul-04	2,757	2,827	69	27	Canada Day
11-Jul-04	2,792	2,831	39	28	
18-Jul-04	2,913	2,936	23	29	
25-Jul-04	2,983	2,988	4	30	
1-Aug-04	2,933	2,955	22	31	
8-Aug-04	2,843	2,884	40	32	Civic Holiday
15-Aug-04	2,828	2,947	119	33	
22-Aug-04	2,809	2,853	44	34	
29-Aug-04	3,029	2,932	-97	35	
5-Sep-04	2,949	2,874	-75	36	
12-Sep-04	2,847	2,805	-42	37	
19-Sep-04	2,878	2,809	-68	38	
26-Sep-04	2,893	2,812	-81	39	
3-Oct-04	2,780	2,835	55	40	
10-Oct-04	2,745	2,784	39	41	
17-Oct-04	2,716	2,752	35	42	Thanksgiving
24-Oct-04	2,826	2,844	18	43	
31-Oct-04	2,796	2,900	104	44	
7-Nov-04	2,859	2,888	29	45	
14-Nov-04	2,964	2,942	-21	46	Rememberance Day
21-Nov-04	2,885	3,044	159	47	
28-Nov-04	3,005	3,055	50	48	

5-Dec-04	3,096	3,170	74	49	
12-Dec-04	3,170	3,217	47	50	
19-Dec-04	3,258	3,169	-88	51	
26-Dec-04	3,229	3,084	-146	52	All-Time Winter Peak, Christmas & Boxing Day
	152,501	152,703	100.13%		
2-Jan-05	2,906	3,008	103	53	New Years Day
9-Jan-05	3,186	3,226	39	1	
16-Jan-05	3,215	3,294	79	2	
23-Jan-05	3,529	3,334	-195	3	All-Time Weekend Peak
30-Jan-05	3,422	3,338	-85	4	
6-Feb-05	3,164	3,302	139	5	
13-Feb-05	3,140	3,248	107	6	
20-Feb-05	3,213	3,236	23	7	
27-Feb-05	3,226	3,146	-81	8	
6-Mar-05	3,169	3,156	-13	9	
13-Mar-05	3,206	3,117	-89	10	
20-Mar-05	3,041	3,032	-9	11	Good Friday
27-Mar-05	2,884	2,907	24	12	Easter Monday
3-Apr-05	2,869	2,919	50	13	
10-Apr-05	2,772	2,899	128	14	5% Voltage Reduction April 7
17-Apr-05	2,706	2,774	68	15	
24-Apr-05	2,738	2,766	28	16	
1-May-05	2,756	2,694	-62	17	
8-May-05	2,662	2,648	-14	18	
15-May-05	2,676	2,674	-2	19	
22-May-05	2,637	2,648	11	20	
29-May-05	2,617	2,633	16	21	Victoria Day
5-Jun-05	2,827	2,744	-84	22	
12-Jun-05	3,348	2,935	-413	23	
19-Jun-05	2,964	2,874	-90	24	
26-Jun-05	3,090	2,964	-126	25	Power Warning June 24
3-Jul-05	3,207	2,996	-211	26	Power Warning June 28-29, Canada Day
10-Jul-05	3,050	2,943	-107	27	
17-Jul-05	3,486	3,120	-366	28	All-Time Peak Demand
24-Jul-05	3,353	3,193	-160	29	Power Warning July 18-21
31-Jul-05	3,069	3,070	0	30	
7-Aug-05	3,312	3,090	-223	31	Power Warning & 5% Voltage Reduction August 3-4
14-Aug-05	3,309	3,117	-192	32	Power Warning August 9-10
21-Aug-05	3,051	3,042	-8	33	
28-Aug-05	2,968	2,946	-22	34	
4-Sep-05	3,016	2,988	-28	35	
11-Sep-05	2,901	2,872	-29	36	Labour Day
18-Sep-05	3,058	2,888	-170	37	
25-Sep-05	2,916	2,847	-68	38	
2-Oct-05	2,772	2,774	2	39	
9-Oct-05	2,805	2,726	-80	40	All-Time October peak
16-Oct-05	2,660	2,699	39	41	Thanksgiving
23-Oct-05	2,757	2,745	-13	42	
30-Oct-05	2,838	2,817	-21	43	
6-Nov-05	2,780	2,894	114	44	
13-Nov-05	2,809	2,859	50	45	Rememberance Day
20-Nov-05	2,910	2,903	-7	46	
27-Nov-05	3,061	2,936	-125	47	All-Time November peak
4-Dec-05	3,020	3,017	-4	48	
11-Dec-05	3,205	3,145	-60	49	
18-Dec-05	3,287	3,171	-116	50	
25-Dec-05	3,107	3,096	-11	51	Christmas Day
	156,671	154,408	98.56%		
1-Jan-06	2,801	2,846	45	52	Boxing Day & New Year's Day
8-Jan-06	3,064	3,138	74	1	
15-Jan-06	3,051	3,222	171	2	
22-Jan-06	3,136	3,306	170	3	
29-Jan-06	3,080	3,259	179	4	
5-Feb-06	3,002	3,200	199	5	
12-Feb-06	3,173	3,167	-6	6	
19-Feb-06	3,183	3,177	-6	7	
26-Feb-06	3,138	3,124	-14	8	
5-Mar-06	3,166	3,121	-45	9	
12-Mar-06	2,959	3,087	129	10	
19-Mar-06	2,996	2,975	-21	11	
26-Mar-06	2,973	2,955	-17	12	

2-Apr-06	2,785	2,888	103	13	
9-Apr-06	2,839	2,899	60	14	
16-Apr-06	2,619	2,666	47	15	Good Friday
23-Apr-06	2,652	2,702	49	16	Easter Monday
30-Apr-06	2,675	2,726	51	17	
7-May-06	2,605	2,594	-11	18	
14-May-06	2,625	2,649	23	19	
21-May-06	2,604	2,612	8	20	Victoria Day
28-May-06	2,630	2,656	25	21	
4-Jun-06	3,032	2,881	-151	22	
11-Jun-06	2,792	2,774	-18	23	
18-Jun-06	2,959	2,951	-8	24	
25-Jun-06	3,024	3,003	-21	25	
2-Jul-06	2,981	2,939	-42	26	
9-Jul-06	2,901	2,803	-98	27	Canada Day
16-Jul-06	3,156	3,023	-134	28	
23-Jul-06	3,190	3,086	-105	29	
30-Jul-06	3,303	3,186	-117	30	
6-Aug-06	3,372	3,265	-107	31	Peak Demand record set
13-Aug-06	2,892	2,907	15	32	Civic Holiday
20-Aug-06	2,991	2,998	8	33	
27-Aug-06	2,892	2,900	8	34	
3-Sep-06	2,773	2,811	38	35	
10-Sep-06	2,694	2,736	43	36	Labour Day
17-Sep-06	2,718	2,743	25	37	
24-Sep-06	2,700	2,737	36	38	
1-Oct-06	2,663	2,665	2	39	
8-Oct-06	2,649	2,657	8	40	
15-Oct-06	2,639	2,615	-24	41	Thanksgiving
22-Oct-06	2,718	2,685	-33	42	
29-Oct-06	2,798	2,777	-20	43	
5-Nov-06	2,824	2,852	28	44	
12-Nov-06	2,785	2,847	62	45	
19-Nov-06	2,843	2,890	47	46	
26-Nov-06	2,865	2,911	46	47	
3-Dec-06	2,921	3,008	86	48	
10-Dec-06	3,122	3,227	105	49	
17-Dec-06	2,945	3,036	91	50	
24-Dec-06	2,899	3,001	101	51	
31-Dec-06	2,671	2,768	97	52	Christmas & Boxing Day
	153,470	154,651	100.77%		

7-Jan-07	2,783	2,913	131	1	New Years Day
14-Jan-07	3,047	3,112	65	2	
21-Jan-07	3,212	3,262	50	3	
28-Jan-07	3,260	3,302	42	4	
4-Feb-07	3,289	3,252	-37	5	
11-Feb-07	3,347	3,248	-100	6	
18-Feb-07	3,341	3,238	-103	7	Winter Peak Demand
25-Feb-07	3,162	3,071	-91	8	
4-Mar-07	3,075	3,036	-40	9	
11-Mar-07	3,174	3,133	-41	10	
18-Mar-07	2,950	2,972	22	11	
25-Mar-07	2,947	2,954	6	12	
1-Apr-07	2,769	2,813	44	13	
8-Apr-07	2,839	2,764	-75	14	Good Friday
15-Apr-07	2,891	2,838	-53	15	Easter Monday
22-Apr-07	2,695	2,716	21	16	
29-Apr-07	2,651	2,677	26	17	
6-May-07	2,591	2,576	-15	18	
13-May-07	2,615	2,618	3	19	
20-May-07	2,620	2,621	1	20	
27-May-07	2,696	2,693	-3	21	
3-Jun-07	2,932	2,860	-72	22	
10-Jun-07	2,745	2,713	-32	23	
17-Jun-07	3,065	2,942	-123	24	
24-Jun-07	2,890	2,834	-56	25	
1-Jul-07	3,070	3,018	-52	26	
8-Jul-07	2,778	2,826	48	27	Canada Day
15-Jul-07	2,919	2,947	28	28	
22-Jul-07	2,837	2,886	49	29	
29-Jul-07	3,014	3,050	37	30	
5-Aug-07	3,293	3,238	-54	31	

12-Aug-07	3,091	2,983	-108	32	Civic Holiday
19-Aug-07	2,880	2,838	-43	33	
26-Aug-07	2,934	2,863	-71	34	
2-Sep-07	2,936	2,888	-49	35	
9-Sep-07	2,956	2,879	-77	36	Labour Day
16-Sep-07	2,693	2,695	2	37	
23-Sep-07	2,762	2,728	-34	38	
30-Sep-07	2,789	2,746	-43	39	
7-Oct-07	2,748	2,834	87	40	
14-Oct-07	2,652	2,699	47	41	Thanksgiving Day
21-Oct-07	2,656	2,689	33	42	
28-Oct-07	2,666	2,686	21	43	
4-Nov-07	2,693	2,684	-8	44	
11-Nov-07	2,821	2,797	-24	45	
18-Nov-07	2,831	2,811	-20	46	
25-Nov-07	2,967	2,944	-23	47	
2-Dec-07	3,089	3,071	-18	48	
9-Dec-07	3,153	3,145	-8	49	
16-Dec-07	3,200	3,185	-16	50	
23-Dec-07	3,080	3,056	-25	51	
30-Dec-07	2,720	2,674	-46	52	Christmas & Boxing Day
	151,814	151,018	99.48%		

ATTACHMENT C

REFERENCE: BOARD STAFF QUESTION 37

Table 1
Tax Calculations

Description	2006 Board Approved	2006 Actual	2007 Actual	2008 Bridge	2009 Test
Determination of Taxable Income					
Utility Income Before Taxes	2,192,713	2,144,260	1,419,837	2,010,637	3,450,035
Book to Tax Adjustments					
Additions to Accounting Income:					
Depreciation and amortization	2,678,878	2,900,527	3,149,121	3,224,320	3,540,000
Income or Loss for tax Purposes-joint ventures or partnerships				0	0
Employee Benefit Plans - accrued, not paid	0				
Meals & entertainment / Mileage	0	2,547		0	0
Non-deductible club fees and dues				0	0
Taxable Capital Gains	0			0	0
Tax reserves beginning of year		1,708,747	1,262,742	0	0
Reserves from financial statements -balance at year end		207,709		0	0
Regulatory asset write-downs and recoveries					
Debt financing expenses for book purposes				0	0
Total Additions	**2,678,878**	**4,819,530**	**4,411,863**	**3,224,320**	**3,540,000**
Deductions from Accounting Income:					
Capital Cost Allowance	1,871,046	1,941,852	2,133,921	2,453,617	2,626,483
Gain on disposal of assets per financial statements	0			0	0
Excess interest	158,097				
Cumulative eligible capital deduction	0			0	0
Reserves from financial statements -balance at year end		315,900	207,709	0	0
Tax reserves end of year				0	0
Amortization of Deferred Asset	0			0	0
Adj for Employee Future Benefits.	0			0	0
Net Capital Loss from Preceding Year	0			0	0
Total Deductions	**2,029,143**	**2,257,752**	**2,341,630**	**2,453,617**	**2,626,483**
Regulatory Taxable Income	**2,842,448**	**4,706,038**	**3,490,070**	**2,781,340**	**4,363,552**
Corporate Income Tax Rate	36.12%	36.12%	36.12%	33.50%	33.00%
Subtotal	**1,026,692**				
Less: R&D ITC (0.3)					
Regulatory Income Tax	**1,026,692**	**1,699,821**	**1,260,613**	**931,749**	**1,439,972**
Calculation of Utility Income Taxes					
Income Taxes	1,026,692	1,699,821	1,260,613	931,749	1,439,972
Large Corporation Tax	0	0	0	0	0
Ontario Capital Tax	119,514	121,712	124,820	103,858	113,781
Total Taxes	**1,146,206**	**1,821,533**	**1,385,433**	**1,035,607**	**1,553,753**
Tax Rates					
Federal Tax	22.1%	22.1%	22.1%	19.5%	19.0%
Federal Surtax	0.00%	0.00%	0.00%	0.0%	0.0%
Provincial Tax	14.0%	14.0%	14.0%	14.0%	14.0%
Total Tax Rate	**36.1%**	**36.1%**	**36.1%**	**33.5%**	**33.0%**
Calculation of Large Corporation Tax					
Total Rate Base	45,634,447				
Less: Exemption	50,000,000				
Taxable Capital	**(4,365,553)**				
LCT Rate	0.125%				
Subtotal	0				
Federal Surtax	0				
Large Corporation Tax	**0**				
Calculation of Ontario Capital Tax					
Total Rate Base	49,838,057	50,570,554	56,296,445	53,571,505	54,118,594
Adjustments	0	0	0	7,587,642	11,443,278
Less Exemption	10,000,000	10,000,000	12,500,000	15,000,000	15,000,000

Taxable Capital /Deemed taxable capital	**39,838,057**	**40,570,554**	**43,796,445**	**46,159,147**	**50,561,872**
OCT Rate	0.30%	0.30%	0.29%	0.23%	0.23%
Ontario Capital Tax	**119,514**	**121,712**	**124,820**	**103,858**	**113,781**

Summary of Income Taxes

Description	2006 Board Approved			2008 Bridge	2009 Test
Income Taxes	1,026,692	1,699,821	1,260,613	931,749	1,439,972
Large Corporation Tax	0	0	0		
Ontario Capital Tax	119,514	121,712	124,820	103,858	113,781
Total Taxes	**1,146,206**	**1,821,533**	**1,385,433**	**1,035,607**	**1,553,753**

ATTACHMENT D

REFERENCE: BOARD STAFF QUESTION 39(b)

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY Peterborough Distribution Inc.
Application ID NUMBER EB-2008-0241

Date 22-Jan-09

Enter appropriate data in cells which are highlighted in yellow only.
Enter the total applied for Regulatory Asset amounts for each account in the appropriate cells below:
Debits should be recorded as positive numbers and credits should be recorded as negative numbers.
Repeat cells going across as necessary for each year in application

		2005								
Account Description	**Account Number**	**Opening Principal Amounts as of Jan-1-05** [1]	**Transactions (additions) during 2005, excluding interest and adjustments** [5]	**Transactions (reductions) during 2005, excluding interest and adjustments** [5]	**Adjustments during 2005 - instructed by Board** [2]	**Adjustments during 2005 - other** [3]	**Closing Principal Balance as of Dec-31-05**	**Opening Interest Amounts as of Jan-1-05**	**Interest Jan-1 to Dec31-05**	**Closing Interest Amounts as of Dec-31-05**
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 67,548	$ 74,235				$ 141,783	$ 622	$ 3,898	$ 4,521
Other Regulatory Assets - Sub-Account - Pension Contributions	1508						$ -			$ -
Other Regulatory Assets - Sub-Account - Other [6]	1508						$ -			$ -
Other Regulatory Assets - Sub-Account - Other [6]	1508						$ -			$ -
Other Regulatory Assets - Sub-Account - Other [6]	1508						$ -			$ -
Retail Cost Variance Account - Retail	1518						$ -			$ -
Misc. Deferred Debits	1525						$ -			$ -
Retail Cost Variance Account - STR	1548						$ -			$ -
Qualifying Transition Costs [4]	1570		n/a	n/a			$ -			$ -
Pre-Market Opening Energy Variances Total [4]	1571		n/a	n/a			$ -			$ -
Extra-Ordinary Event Costs	1572						$ -			$ -
Deferred Rate Impact Amounts	1574						$ -			$ -
RSVA -- One-time Wholesale Market Service	1582						$ -			$ -
2006 PILs & Taxes Variance	1592	n/a	n/a	n/a	n/a	n/a		n/a	n/a	
Other Deferred Credits	2425						$ -			$ -
Sub-Total		$ 67,548	$ 74,235	$ -	$ -	$ -	$ 141,783	$ 622	$ 3,898	$ 4,521
Smart Meter Capital and Recovery Offset	1555	$ -								
Smart Meter Operation, Maintenance and Administration	1556									
Deferred Payments in Lieu of Taxes	1562						$ -			$ -
Deferred PILs Contra Account [8]	1563						$ -			$ -
CDM Expenditures and Recoveries	1565						$ -			$ -
CDM Contra Account	1566						$ -			$ -
Recovery of Regulatory Asset Balances	1590						$ -			$ -
No sub-total										
Low Voltage Variance Account	1550						$ -			$ -
RSVA - Wholesale Market Service Charge	1580						$ -			$ -
RSVA - Retail Transmission Network Charge	1584						$ -			$ -
RSVA - Retail Transmission Connection Charge	1586						$ -			$ -
RSVA - Power (including Global Adjustment)	1588						$ -			$ -
RSVA - Power - Sub-Account - Global Adjustment	1588						$ -			$ -
Sub-Total		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Footnotes
1 As per general ledger, if does not agree to Dec-31-04 balance filed in 2006 EDR then provide supplementary analysis
2 Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs write-off, and etc.
3 Provide supporting statement indicating nature of this adjustments and periods they relate to
4 Closed April 30, 2002
5 For RSVA accounts only, report the net additions to the account during the year. For all other accounts, record the additions and reductions separately.
6 Please describe "other" components of 1508 and add more component lines if necessary.
7 Interest projected on December 31, 2007 closing principal balance.
8 1563 is a contra-account and is not included in the total but is shown on a memo basis. Account 1562 establishes the obligation to the ratepayer.

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY Peterborough Distribution Inc.
Application ID NUMBER EB-2008-0241

Date 22-Jan-09

Account Description	Account Number	2006 Opening Principal Amounts as of Jan-1-06	Transactions (additions) during 2006, excluding interest and adjustments[5]	Transactions (reductions) during 2006, excluding interest and adjustments[5]	Adjustments during 2006 - instructed by Board[2]	Adjustments during 2006 - other[3]	Transfer of Board-approved amounts to 1590 as per 2006 EDR	Closing Principal Balance as of Dec-31-06	Opening Interest Amounts as of Jan-1-06	Interest Jan-1 to Dec31-06	Transfer of Board-approved amounts to 1590 as per 2006 EDR	Closing Interest Amounts as of Dec-31-06
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 141,783			$ 63,983	$ (28,821)	$ (102,710)	$ 74,235	$ 4,521	$ 4,499	$ (5,261)	$ 3,759
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -						$ -	$ -			$ -
Other Regulatory Assets - Sub-Account - Other[6]	1508	$ -						$ -	$ -			$ -
Other Regulatory Assets - Sub-Account - Other[6]	1508	$ -						$ -	$ -			$ -
Other Regulatory Assets - Sub-Account - Other[6]	1508	$ -						$ -	$ -			$ -
Retail Cost Variance Account - Retail	1518	$ -						$ -	$ -			$ -
Misc. Deferred Debits	1525	$ -						$ -	$ -			$ -
Retail Cost Variance Account - STR	1548	$ -						$ -	$ -			$ -
Qualifying Transition Costs[4]	1570	$ -	n/a	n/a				$ -	$ -			$ -
Pre-Market Opening Energy Variances Total[4]	1571	$ -	n/a	n/a				$ -	$ -			$ -
Extra-Ordinary Event Costs	1572	$ -						$ -	$ -			$ -
Deferred Rate Impact Amounts	1574	$ -						$ -	$ -			$ -
RSVA -- One-time Wholesale Market Service	1582	$ -						$ -	$ -			$ -
2006 PILs & Taxes Variance	1592	$ -						$ -	$ -			$ -
Other Deferred Credits	2425	$ -						$ -	$ -			$ -
Sub-Total		$ 141,783	$ -	$ -	$ 63,983	$ (28,821)	$ (102,710)	$ 74,235	$ 4,521	$ 4,499	$ (5,261)	$ 3,759
Smart Meter Capital and Recovery Offset	1555	$ -						$ -	$ -			$ -
Smart Meter Operation, Maintenance and Administration	1556							$ -	$ -			$ -
Deferred Payments in Lieu of Taxes	1562	$ -						$ -	$ -			$ -
Deferred PILs Contra Account[8]	1563	$ -						$ -	$ -			$ -
CDM Expenditures and Recoveries	1565	$ -						$ -	$ -			$ -
CDM Contra Account	1566	$ -						$ -	$ -			$ -
Recovery of Regulatory Asset Balances	1590	$ -						$ -	$ -			$ -
No sub-total												
Low Voltage Variance Account	1550	$ -	$ (147,607)					$ (147,607)	$ -	$ (1,756)		$ (1,756)
RSVA - Wholesale Market Service Charge	1580	$ -						$ -	$ -			$ -
RSVA - Retail Transmission Network Charge	1584	$ -						$ -	$ -			$ -
RSVA - Retail Transmission Connection Charge	1586	$ -						$ -	$ -			$ -
RSVA - Power (including Global Adjustment)	1588	$ -						$ -	$ -			$ -
RSVA - Power - Sub-Account - Global Adjustment	1588	$ -						$ -	$ -			$ -
Sub-Total		$ -	$ (147,607)	$ -	$ -	$ -	$ -	$ (147,607)	$ -	$ (1,756)	$ -	$ (1,756)

Footnotes

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Peterborough Distribution Inc.
Application ID NUMBER	EB-2008-0241
Date	**22-Jan-09**

Account Description	**Account Number**	**2007** Opening Principal Amounts as of Jan-1-07	Transactions (additions) during 2007, excluding interest and adjustments[5]	Transactions (reductions) during 2007, excluding interest and adjustments[5]	Adjustments during 2007 - instructed by Board[2]	Adjustments during 2007 - other[3]	Closing Principal Balance as of Dec-31-07	Opening Interest Amounts as of Jan-1-07	Interest Jan-1 to Dec31-07	Closing Interest Amounts as of Dec-31-07
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 74,235					$ 74,235	$ 3,759	$ 3,510	$ 7,270
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -					$ -	$ -		$ -
Other Regulatory Assets - Sub-Account - Other[6]	1508	$ -					$ -	$ -		$ -
Other Regulatory Assets - Sub-Account - Other[6]	1508	$ -					$ -	$ -		$ -
Other Regulatory Assets - Sub-Account - Other[6]	1508	$ -					$ -	$ -		$ -
Retail Cost Variance Account - Retail	1518	$ -					$ -	$ -		$ -
Misc. Deferred Debits	1525	$ -					$ -	$ -		$ -
Retail Cost Variance Account - STR	1548	$ -					$ -	$ -		$ -
Qualifying Transition Costs[4]	1570	$ -	n/a	n/a			$ -	$ -		$ -
Pre-Market Opening Energy Variances Total[4]	1571	$ -	n/a	n/a			$ -	$ -		$ -
Extra-Ordinary Event Costs	1572	$ -					$ -	$ -		$ -
Deferred Rate Impact Amounts	1574	$ -					$ -	$ -		$ -
RSVA -- One-time Wholesale Market Service	1582	$ -					$ -	$ -		$ -
2006 PILs & Taxes Variance	1592	$ -					$ -	$ -		$ -
Other Deferred Credits	2425	$ -					$ -	$ -		$ -
Sub-Total		$ 74,235	$ -	$ -	$ -	$ -	$ 74,235	$ 3,759	$ 3,510	$ 7,270
Smart Meter Capital and Recovery Offset	1555	$ -					$ -	$ -		$ -
Smart Meter Operation, Maintenance and Administration	1556	$ -					$ -	$ -		$ -
Deferred Payments in Lieu of Taxes	1562	$ -					$ -	$ -		$ -
Deferred PILs Contra Account[8]	1563	$ -					$ -	$ -		$ -
CDM Expenditures and Recoveries	1565	$ -					$ -	$ -		$ -
CDM Contra Account	1566	$ -					$ -	$ -		$ -
Recovery of Regulatory Asset Balances	1590	$ -					$ -	$ -		$ -
No sub-total										
Low Voltage Variance Account	1550	$ (147,607)	$ (209,358)				$ (356,965)	$ (1,756)	$ (11,810)	$ (13,566)
RSVA - Wholesale Market Service Charge	1580	$ -					$ -	$ -		$ -
RSVA - Retail Transmission Network Charge	1584	$ -					$ -	$ -		$ -
RSVA - Retail Transmission Connection Charge	1586	$ -					$ -	$ -		$ -
RSVA - Power (including Global Adjustment)	1588	$ -					$ -	$ -		$ -
RSVA - Power - Sub-Account - Global Adjustment	1588	$ -					$ -	$ -		
Sub-Total		$ (147,607)	$ (209,358)	$ -	$ -	$ -	$ (356,965)	$ (1,756)	$ (11,810)	$ (13,566)

Footnotes

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Peterborough Distribution Inc.
Application ID NUMBER	EB-2008-0241
Date	**22-Jan-09**

Account Description	**Account Number**	**Projected Interest on Dec 31 -07 balance from Jan 1, 2008 to Dec 31, 2008** [7]	**Projected Interest on Dec 31 -07 balance from Jan 1, 2009 to April 30, 2009** [7]	**Balance before Forecasted Transactions**	**Forecasted Transactions, Excluding Interest from Jan 1, 2008 to Dec 31, 2008**	**Forecasted Transactions, Excluding Interest from Jan 1, 2009 to April 30, 2009**	**Projected Interest from Jan 1, 2008 to April 30, 2009 on Forecasted Transx (Excl Interest) from Jan 1, 2008 to December 31, 2008**	**Projected Interest from Jan 1, 2009 to April 30, 2009 on Forecasted Transx (Excl Interest) from Jan 1, 2009 to April 30, 2009**	**Balance**
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508			$ 81,505	$ -	$ -	$ -	$ -	$ 81,505
Other Regulatory Assets - Sub-Account - Pension Contributions	1508			$ -					$ -
Other Regulatory Assets - Sub-Account - Other [6]	1508			$ -					$ -
Other Regulatory Assets - Sub-Account - Other [6]	1508			$ -					$ -
Other Regulatory Assets - Sub-Account - Other [6]	1508			$ -					$ -
Retail Cost Variance Account - Retail	1518			$ -					$ -
Misc. Deferred Debits	1525			$ -					$ -
Retail Cost Variance Account - STR	1548			$ -					$ -
Qualifying Transition Costs [4]	1570			$ -					$ -
Pre-Market Opening Energy Variances Total [4]	1571			$ -					$ -
Extra-Ordinary Event Costs	1572			$ -					$ -
Deferred Rate Impact Amounts	1574			$ -					$ -
RSVA -- One-time Wholesale Market Service	1582			$ -	$ -	$ -	$ -	$ -	$ -
2006 PILs & Taxes Variance	1592			$ -					$ -
Other Deferred Credits	2425			$ -					$ -
Sub-Total		$ -	$ -	$ 81,505	$ -	$ -	$ -	$ -	$ 81,505
Smart Meter Capital and Recovery Offset	1555								
Smart Meter Operation, Maintenance and Administration	1556								
Deferred Payments in Lieu of Taxes	1562			$ -					$ -
Deferred PILs Contra Account [8]	1563			$ -					$ -
CDM Expenditures and Recoveries	1565								
CDM Contra Account	1566								
Recovery of Regulatory Asset Balances	1590			$ -					$ -
No sub-total									
Low Voltage Variance Account	1550			$ (370,531)					$ (370,531)
RSVA - Wholesale Market Service Charge	1580			$ -					$ -
RSVA - Retail Transmission Network Charge	1584			$ -					$ -
RSVA - Retail Transmission Connection Charge	1586			$ -					$ -
RSVA - Power (including Global Adjustment)	1588			$ -					$ -
RSVA - Power - Sub-Account - Global Adjustment	1588			$ -					$ -
Sub-Total		$ -	$ -	$ (370,531)	$ -	$ -	$ -	$ -	$ (370,531)

Footnotes

ATTACHMENT E

REFERENCE: BOARD STAFF QUESTION 40(a)

PROMISSORY NOTE

Principal: $437,000
lawful money of Canada

Made and delivered
at Peterborough, Ontario
as of this 28th day of September, 2001

FOR VALUE RECEIVED, PETERBOROUGH DISTRIBUTION INC., a corporation incorporated pursuant to the laws of the Province of Ontario, the maker hereof and hereinafter referred to as the "Debtor" hereby unconditionally promises to pay to the order of the CORPORATION OF THE CITY OF PETERBOROUGH, a municipal corporation, and hereinafter referred to as the "City" the principal sum of Four Hundred and Thirty-Seven Thousand Dollars ($437,000.00) (the "principal sum"), in lawful money of Canada and interest thereon at the rate and in accordance with the terms and conditions stated below:

1. LOAN AGREEMENT

This Promissory Note is issued pursuant to and is subject to the terms of a loan agreement dated December 13, 2001 between the City, the Debtor and others. In addition, this Promissory Note has been issued in connection with the acquisition by the Debtor of all issued and outstanding shares in the capital stock of Asphodel-Norwood Distribution Inc.

2. INTEREST RATE

Interest on the unpaid principal sum of this Promissory Note shall accrue at a rate per annum equal to the Prime Rate in effect on the date of advance, less 1.25%. "Prime Rate" means at any time the prime lending rate of interest expressed as the rate per annum which the Royal Bank of Canada establishes at its head office in Toronto as the reference rate of interest it will charge at such time for demand loans in Canadian dollars to its Canadian customers, and which it refers to as its "Prime Rate". Interest hereunder shall be calculated and payable monthly in arrears from the date hereof until payment in full, both before and after default and judgment, with interest on overdue interest at the same rate. The first interest payment will be due on December 31, 2001 and subsequent payments will be due each month thereafter until the payment of this Promissory Note in full.

3. TERMS OF PAYMENT

The principal sum and all interest due under this Promissory Note shall be payable on demand as follows:

(a) the principal sum shall be due and payable on demand; and

(b) the interest accrued on the principal sum prior to its repayment shall be due and payable monthly commencing on August 31, 2001 with the first payment due and payable on September 30, 2001.

4. PREPAYMENT

The Debtor may at any time, without penalty, repay in whole or in part the principal amount and interest owing under this Promissory Note. Any prepayment shall be applied first to interest until it has been paid in full and then to principal.

5. EVENT OF DEFAULT

The principal amount due hereunder together with the interest will accelerate and become due if an Event of Default (hereinafter defined) occurs. An "Event of Default" shall exist under this Promissory Note if the Debtor: (i) petitions or applies to any tribunal for or consents to the appointment of the receiver, trustee or liquidator of the Debtor or of all or any substantial part of its properties or assets, (ii) admits in writing its inability to pay its debts as they mature, (iii) makes a general assignment for the benefit of its creditors, (iv) is adjudicated bankrupt or insolvent; (v) files voluntarily or has filed against it a petition in bankruptcy or a petition seeking reorganization or an arrangement with creditors to take advantage of any statute, or (vi) breaches any of its obligations or is in default under this Promissory Note or the security described in section 12 hereof made in favour of the City and executed the date hereof by the Debtor.

6. WAIVER OF NOTICE IN EVENT OF DEFAULT

The Debtor hereby waives demand, protest and notice of maturity, non-payment or protests, and any other requirements necessary to hold it liable as maker and endorser of this Promissory Note. The Debtor further agrees to pay all costs of collection, including legal fees on a solicitor and client basis, in case the principal of this Promissory Note or any payment on the principal or interest thereon is not made at the maturity thereof or when otherwise due, or in case it becomes necessary to protect the security referred to in section 12 and whether or not legal proceedings are commenced.

7. INTEREST RATE AFTER DEFAULT AND/OR MATURITY

During the period of any default under the terms of this Promissory Note and following maturity thereof, the interest rate on the entire indebtedness then outstanding shall be at the aforesaid rate, computed from the date of default and/or maturity. If any payment of interest is not made when due, interest on the overdue interest shall be due and payable, calculated at the aforesaid rate.

8. RIGHTS AND REMEDIES IN EVENT OF DEFAULT

The rights and remedies of the City under this Promissory Note and under the security described in section 12 which secures payment and performance of this Promissory Note, which the City may have at law or in equity against the Debtor, or any other persons or legal entities, shall be distinct, separate and cumulative, and shall not be deemed inconsistent with one another, and none of the said rights whether or not exercised by the City, shall be deemed to be to the exclusion of any other, and any one or more of said rights and remedies may be exercised at the same time. The obligations of this Promissory Note shall continue until the entire debt evidenced hereby is paid, notwithstanding any court action or actions taken by the City which may be brought to recover any amounts due and payable under this Promissory Note. No delay or failure by the City in the enforcement of any covenant, promise or agreement of the Debtor hereunder shall constitute or be deemed to constitute a waiver of such right. Any waivers of the City shall only occur and be valid when set forth in writing by the City. No waiver of any event of default shall discharge or release any person at any time liable for the payment of this Promissory Note from such liability. No single or partial exercise of any of the City's powers hereunder shall preclude other and further exercise thereof or the exercise of any other power. The City may extend the maturity of this Promissory Note from time to time without in any way affecting the liability of the Debtor under the security referred to in section 12.

9. ASSIGNMENT

This Promissory Note may be assigned by the City in whole or in part and without restraint, and upon notice of such assignment to the Debtor the assignee hereof shall for all purposes be deemed to be a holder or the holder of a beneficial interest herein, as the case may be.

10. GOVERNING LAW

This Promissory Note shall be governed by the laws of the Province of Ontario and the laws of Canada applicable therein, which laws shall be applicable to the interpretation, construction and enforcement thereof.

11. GENERAL PROVISIONS

This Promissory Note may not be changed, modified, discharged or cancelled, orally or in any manner, other than by agreement in writing signed by the parties hereto or their respective successors and assigns, and the provisions hereof shall bind and enure to the benefit of the respective successors and assigns of the Debtor and the City.

12. **SECURITY**

This Promissory Note shall be secured by a security agreement which shall grant to the City a security interest in all of the personal property of the Debtor and a charge against the real property of the Debtor and in all of the assets of Asphodel-Norwood Distribution Inc.

IN WITNESS WHEREOF the Debtor has duly executed this Promissory Note as of the date first appearing above.

PETERBOROUGH DISTRIBUTION INC.

By: Robt T. Ellis Pres.

By:

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slp 10-11-2000 - 12-28-2001

PROMISSORY NOTE

Principal: $1,063,000
lawful money of Canada

Made and delivered
at Peterborough, Ontario
as of this 28th day of September, 2001

FOR VALUE RECEIVED, PETERBOROUGH DISTRIBUTION INC., a corporation incorporated pursuant to the laws of the Province of Ontario, the maker hereof and hereinafter referred to as the "Debtor" hereby unconditionally promises to pay to the order of the CORPORATION OF THE CITY OF PETERBOROUGH, a municipal corporation, and hereinafter referred to as the "City" the principal sum of One Million, Sixty-Three Thousand Dollars ($1,063,000.00) (the "principal sum"), in lawful money of Canada and interest thereon at the rate and in accordance with the terms and conditions stated below:

1. LOAN AGREEMENT

This Promissory Note is issued pursuant to and is subject to the terms of a loan agreement dated December 13, 2001 between the City, the Debtor and others. In addition, this Promissory Note has been issued in connection with the acquisition by the Debtor of all issued and outstanding shares in the capital stock of Lakefield Distribution Inc.

2. INTEREST RATE

Interest on the unpaid principal sum of this Promissory Note shall accrue at a rate per annum equal to the Prime Rate in effect on the date of advance, less 1.25%. "Prime Rate" means at any time the prime lending rate of interest expressed as the rate per annum which the Royal Bank of Canada establishes at its head office in Toronto as the reference rate of interest it will charge at such time for demand loans in Canadian dollars to its Canadian customers, and which it refers to as its "Prime Rate". Interest hereunder shall be calculated and payable monthly in arrears from the date hereof until payment in full, both before and after default and judgment, with interest on overdue interest at the same rate. The first interest payment will be due on December 31, 2001 and subsequent payments will be due each month thereafter until the payment of this Promissory Note in full.

3. TERMS OF PAYMENT

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(a) the principal sum shall be due and payable on demand; and

(b) the interest accrued on the principal sum prior to its repayment shall be due and payable monthly commencing on August 31, 2001 with the first payment due and payable on September 30, 2001.

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The principal amount due hereunder together with the interest will accelerate and become due if an Event of Default (hereinafter defined) occurs. An "Event of Default" shall exist under this Promissory Note if the Debtor: (i) petitions or applies to any tribunal for or consents to the appointment of the receiver, trustee or liquidator of the Debtor or of all or any substantial part of its properties or assets, (ii) admits in writing its inability to pay its debts as they mature, (iii) makes a general assignment for the benefit of its creditors, (iv) is adjudicated bankrupt or insolvent; (v) files voluntarily or has filed against it a petition in bankruptcy or a petition seeking reorganization or an arrangement with creditors to take advantage of any statute, or (vi) breaches any of its obligations or is in default under this Promissory Note or the security described in section 12 hereof made in favour of the City and executed the date hereof by the Debtor.

6. **WAIVER OF NOTICE IN EVENT OF DEFAULT**

The Debtor hereby waives demand, protest and notice of maturity, non-payment or protests, and any other requirements necessary to hold it liable as maker and endorser of this Promissory Note. The Debtor further agrees to pay all costs of collection, including legal fees on a solicitor and client basis, in case the principal of this Promissory Note or any payment on the principal or interest thereon is not made at the maturity thereof or when otherwise due, or in case it becomes necessary to protect the security referred to in section 12 and whether or not legal proceedings are commenced.

7. **INTEREST RATE AFTER DEFAULT AND/OR MATURITY**

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8. **RIGHTS AND REMEDIES IN EVENT OF DEFAULT**

The rights and remedies of the City under this Promissory Note and under the security described in section 12 which secures payment and performance of this Promissory Note, which the City may have at law or in equity against the Debtor, or any other persons or legal entities, shall be distinct, separate and cumulative, and shall not be deemed inconsistent with one another, and none of the said rights whether or not exercised by the City, shall be deemed to be to the exclusion of any other, and any one or more of said rights and remedies may be exercised at the same time. The obligations of this Promissory Note shall continue until the entire debt evidenced hereby is paid, notwithstanding any court action or actions taken by the City which may be brought to recover any amounts due and payable under this Promissory Note. No delay or failure by the City in the enforcement of any covenant, promise or agreement of the Debtor hereunder shall constitute or be deemed to constitute a waiver of such right. Any waivers of the City shall only occur and be valid when set forth in writing by the City. No waiver of any event of default shall discharge or release any person at any time liable for the payment of this Promissory Note from such liability. No single or partial exercise of any of the City's powers hereunder shall preclude other and further exercise thereof or the exercise of any other power. The City may extend the maturity of this Promissory Note from time to time without in any way affecting the liability of the Debtor under the security referred to in section 12.

9. **ASSIGNMENT**

This Promissory Note may be assigned by the City in whole or in part and without restraint, and upon notice of such assignment to the Debtor the assignee hereof shall for all purposes be deemed to be a holder or the holder of a beneficial interest herein, as the case may be.

10. **GOVERNING LAW**

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11. **GENERAL PROVISIONS**

This Promissory Note may not be changed, modified, discharged or cancelled, orally or in any manner, other than by agreement in writing signed by the parties hereto or their respective successors and assigns, and the provisions hereof shall bind and enure to the benefit of the respective successors and assigns of the Debtor and the City.

12. SECURITY

This Promissory Note shall be secured by a security agreement which shall grant to the City a security interest in all of the personal property of the Debtor and a charge against the real property of the Debtor and in all of the assets of Lakefield Distribution Inc.

IN WITNESS WHEREOF the Debtor has duly executed this Promissory Note as of the date first appearing above.

PETERBOROUGH DISTRIBUTION INC.

By: Robert G Fuller PRES.

By:______________________________

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slp 10-11-2000 - 12-28-2001

ATTACHMENT F

REFERENCE: BOARD STAFF QUESTION 41(c) ELECTRONIC VERSION – NOT INCLUDED IN HARD COPIES

ATTACHMENT G

REFERENCE: BOARD STAFF QUESTION 44

Ontario Energy Board
P.O. Box 2319
27th. Floor
2300 Yonge Street
Toronto ON M4P 1E4
Telephone: 416- 481-1967
Facsimile: 416- 440-7656
Toll free: 1-888-632-6273

Commission de l'Énergie de l'Ontario
C.P. 2319
27e étage
2300, rue Yonge
Toronto ON M4P 1E4
Téléphone; 416- 481-1967
Télécopieur: 416- 440-7656
Numéro sans frais: 1-888-632-6273

Ontario

December 17, 2008

To: All Licensed Electricity Distributors and Retailers

Re: Rural or Remote Electricity Rate Protection

Ontario Regulation 442/01, Rural or Remote Electricity Rate Protection ("RRRP") (made under the *Ontario Energy Board Act, 1998*) requires the Ontario Energy Board (the "Board") to calculate the amount to be charged by the Independent Electricity System Operator ("IESO") with respect to the RRRP for each kilowatt-hour of electricity that is withdrawn from the IESO-controlled grid.

Amount to be charged by the IESO for RRRP

Based on the demand forecast provided by the IESO, the Board has determined that the amount to be charged by the IESO with respect to the RRRP shall remain at the current level of 0.1 cents per kilowatt-hour effective January 1, 2009. Effective May 1, 2009, the IESO's RRRP charge shall be 0.13 cents per kilowatt-hour.

Amount to be Charged by Distributors and Retailers for RRRP

Effective January 1, 2009, the RRRP charge shall remain at the current level of 0.1 cents per kilowatt-hour.

Effective May 1, 2009, the RRRP charge shall be 0.13 cents per kilowatt-hour.

After May 1, 2009 the RRRP charge shall remain at 0.13 cents per kilowatt-hour until such time as the Board revises it.

Distributors that currently have a rate application before the Board shall file this letter as an update to their evidence along with a request that the RRRP charge in their tariff sheet be revised to 0.13 cents per kilowatt-hour effective May 1, 2009.

Where a distributor does not have a rate application before the Board, the distributor shall make an application to the Board to alter the RRRP charge in its tariff sheet effective May 1, 2009 to 0.13 cents per kilowatt-hour.

In the collection of this amount from customers, the customer's metered energy consumption shall be adjusted by the Total Loss Factor as approved by the Board.

The Board wishes to remind all distributors and retailers that in accordance with subsection 5(6) of the Regulation:

> A distributor or retailer who bills a consumer for electricity shall aggregate the amount that the consumer is required to contribute to the compensation required by subsection 79(3) of the Act with the wholesale market service rate described in the Electricity Distribution Rate Handbook issued by the Board, as it read on October 31, 2001.

Yours Truly,

Original Signed By

Kirsten Walli
Board Secretary