CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

December 12, 2008

HAND-DELIVERED

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

RE: 2009 ELECTRICITY DISTRIBUTION RATE APPLICATIONS FOR CANADIAN NIAGARA POWER INC. FOR ITS CNPI – EASTERN ONTARIO POWER (EB-2008-0222), CNPI – FORT ERIE (EB-2008-0223) AND CNPI – PORT COLBORNE (EB-2008-0224) SERVICE AREAS

The undersigned acts as in-house counsel for Canadian Niagara Power Inc. ("CNPI") with respect to the above-captioned matter. Please find accompanying this letter two (2) copies of CNPI's responses to the interrogatories submitted to the Board. In addition, electronic copies of the alternative calculations and rate designs along with additional supporting information requested are being provided together with these responses.

We have enclosed a CD containing this electronic media. A PDF version of these responses will, coincidently with this written submission, be filed via the Board's Regulatory Electronic Submission System.

If you have any questions in connection with the above matter, please do not hesitate to contact the undersigned or Doug Bradbury, Director Regulatory Affairs (905) 994-3634.

Yours truly,

R. Scott Hawkes
Vice President, Corporate Services
and General Counsel

RSH:mar

Enclosures

c. Charles Keizer – Ogilvy Renault LLP
Douglas R. Bradbury – CNPI

INTERROGATORY # 1

Ref: Eastern Ontario - Exhibit 8, Tab 1, Schedule 2, Page 2

The table titled Customer Class Revenue-to-Cost Ratios shows the proposed level of over contribution from the GS<50 kW (127.99%) and GS 50 to 4,999 kW (145.03%) customer classes both in revenue-to-cost ratios and real dollars. The other four classes are under contributing with two out of the four classes below the ranges established by the board.

The over contribution by the GS 50 to 4,999 kW customer class is approximately $6,155 annually. Over what period of time is CNPI planning to move its cost allocation ratios to 100% for all customer classes?

RESPONSE:

In the Report of the Board, Application of Cost Allocation for Electricity Distributors, EB-2007-0667, November 28, 2007, ("the Report") the Board concluded that there were appropriate ranges of the Revenue-to-Cost Ratio applicable to each customer class. The Board also concluded in the Report that an incremental approach is appropriate in light of the influencing factors identified in the Report, and that a range approach is preferable to implementation of a specific Revenue-to-Cost Ratio.

However, notwithstanding the notion of 100% cost to revenue recovery, CNPI – Gananoque does recognize the Board's direction with respect to the appropriate ranges identified in the Report. CNPI – Gananoque will follow the Board's direction as it relates to this Application. Should the class specific revenue to cost ratios remain outside the ranges determined in the Report following the Board's review of this Application then CNPI – Gananoque proposes that during the period prior to its next cost of service application, it will strive to migrate all customer classes within the bounds of the Board's range.

INTERROGATORY # 2

Ref: Fort Erie - Exhibit 8, Tab 1, Schedule 2, Page 2

The table titled Customer Class Revenue-to-Cost Ratios shows the proposed level of over contribution from the GS< 50 kW (129.81%) and GS>50 to 4,999 kW (151.44%) customer classes both in revenue-to-cost ratios and real dollars. The other four classes are under contributing with three out of the four classes below the ranges established by the board.

The over contribution by the GS 50 to 4,999 kW customer class is approximately $6,125 annually. Over what period of time is CNPI planning to move its cost allocation ratios to 100% for all customer classes?

RESPONSE:

In the Report of the Board, Application of Cost Allocation for Electricity Distributors, EB-2007-0667, November 28, 2007, ("the Report") the Board concluded that there were appropriate ranges of the Revenue-to-Cost Ratio applicable to each customer class. The Board also concluded in the Report that an incremental approach is appropriate in light of the influencing factors identified in the Report, and that a range approach is preferable to implementation of a specific Revenue-to-Cost Ratio.

However, notwithstanding the notion of 100% cost to revenue recovery, CNPI – Fort Erie does recognize the Board's direction with respect to the appropriate ranges identified in the Report. CNPI – Fort Erie will follow the Board's direction as it relates to this Application. Should the class specific revenue to cost ratios remain outside the ranges determined in the Report following the Board's review of this Application then CNPI – Fort Erie proposes that during the period prior to its next cost of service application, it will strive to migrate all customer classes within the bounds of the Board's range.

INTERROGATORY # 3

Ref: Port Colborne - Exhibit 8, Tab 1, Schedule 2, Page 3

The table titled Customer Class Revenue-to-Cost Ratios shows the proposed level of over contribution (135.58%) from the GS>50 to 4,999 kW customer class both in revenue-to-cost ratios and real dollars. The other five classes are under contributing with three out of the five classes below the ranges established by the board.

The over contribution by the GS 50 to 4,999 kW customer class is approximately $5,457 annually. How and over what period of time if CNPI planning to move its cost allocation ratios to 100% for all customer classes?

RESPONSE:

In the Report of the Board, Application of Cost Allocation for Electricity Distributors, EB-2007-0667, November 28, 2007, ("the Report") the Board concluded that there were appropriate ranges of the Revenue-to-Cost Ratio applicable to each customer class. The Board also concluded in the Report that an incremental approach is appropriate in light of the influencing factors identified in the Report, and that a range approach is preferable to implementation of a specific Revenue-to-Cost Ratio.

However, notwithstanding the notion of 100% cost to revenue recovery, CNPI – Port Colborne does recognize the Board's direction with respect to the appropriate ranges identified in the Report. CNPI – Port Colborne will follow the Board's direction as it relates to this Application. Should the class specific revenue to cost ratios remain outside the ranges determined in the Report following the Board's review of this Application then CNPI – Port Colborne proposes that during the period prior to its next cost of service application, it will strive to migrate all customer classes within the bounds of the Board's range.

INTERROGATORY # 4

Please provide the data for the following tables:

CNPI Eastern Ontario

Customer Size	# of Customers	Total Annual kWhs	Average Monthly Usage	Average Peak kW - monthly
50 kW - 250 kW				
251 kW - 500 kW				
501 kW - 1000 kW				
1001 kW - 3000 kW				
3001 kW - 5000 kW				

CNPI Fort Erie

Customer Size	# of Customers	Total Annual kWhs	Average Monthly Usage	Average Peak kW - monthly
50 kW - 250 kW				
251 kW - 500 kW				
501 kW - 1000 kW				
1001 kW - 3000 kW				
3001 kW - 5000 kW				

CNPI Port Colborne

Customer Size	# of Customers	Total Annual kWhs	Average Monthly Usage	Average Peak kW - monthly
50 kW - 250 kW				
251 kW - 500 kW				
501 kW - 1000 kW				
1001 kW - 3000 kW				
3001 kW - 5000 kW				

RESPONSE:

Pursuant to the Board's letter to AMPCO dated November 6, 2008, CNPI is not required to and chooses not to respond to AMPCO's interrogatory #4.

INTERROGATORY # 5

Please provide a copy of the 2006 cost allocation study submitted to the OEB or the URL link.

RESPONSE:

Provided below are the URL links for the Cost Allocation Studies:

Port Colborne

http://www.rds.oeb.gov.on.ca/webdrawer/webdrawer.dll/webdrawer/search/rec?sm_udf10=EB-2008-0224&sortd1=rs_dateregistered&rows=200

Gananoque

http://www.rds.oeb.gov.on.ca/webdrawer/webdrawer.dll/webdrawer/search/rec?sm_udf10=EB-2008-0222&sortd1=rs_dateregistered&rows=200

Fort Erie

http://www.rds.oeb.gov.on.ca/webdrawer/webdrawer.dll/webdrawer/search/rec?sm_udf10=EB-2008-0223&sortd1=rs_dateregistered&rows=200

INTERROGATORY # 1

Ref: Exhibit 3, Tab 2, Schedule 1, page 16 (Corrected to read page 16)

Total distribution load is shown in the chart on this page. Demand for historical and test years is shown in KW.

a) Please confirm that these figures are the arithmetic sum of monthly peak demand.
b) What were the maximum winter and summer system peak demand for the historical years in the table and what are the forecast winter and summer maximum peak demand for the test year?

RESPONSE:

a) These figures are the arithmetic sums of the monthly customer billing demands.

b) The table shown below provides the actual summer and winter peak demands for CNPI – Eastern Ontario Power for the years 2005 to 2007, the actual year to date information has been provided for 2008. The forecasted peak values are provided for 2009.

Year	2005		2006		2007		2008		2009	
Season	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer
Peak, kW	15,677	15,206	13,647	13,939	13,937	12,096	12,953	12,493	11,500	11,000

INTERROGATORY # 2

Ref: Exhibit 3, Tab 2, Schedule 1, page 6
Exhibit 2, Tab 1, Schedule 1, App. A, page 1 of 7

The chart in the second reference shows the utility's inventory of distribution substations:

a) The "Thermal Plant" is shown as offloaded in 2007. Has it been decommissioned or will it be refurbished and placed back in service?
b) The "Main" station is noted as 2 transformers with a capacity of 45 MVA. Please confirm that the total is the sum of the 2 transformers. What is the normal operating capacity of the station?
c) Why does the "Main" station have much more transformation capacity than is needed to supply the system peak load?

RESPONSE:

a) The Thermal Plant Substation has been decommissioned and will not be refurbished or placed back in service.

b) The capacity noted is the sum of the two transformer capacities. The normal operating capacity of the Main Station is 20 MVA, which is the capacity of the smaller transformer.

c) As noted above, the operating capacity of the Station is 20 MVA. The Station is designed on a Dual-Element Spot Network principle, where either transformer can supply the system peak load. This design is prudent because the Main Station is the sole source of electricity supply to Gananoque, and ensures that the load can still be served by the remaining transformer if one transformer is out of service for maintenance or because of failure.

INTERROGATORY # 3

Ref: Exhibit 2, Tab 1, Schedule 1, App. A, page 2 of 7

a) In the description of the distribution system on lines 1 to 8 of this schedule, the Town Loop East Side is described as being unable to carry the Town's peak load because of undersized conductor. Please provide details of the Town's peak load and the load carrying capacity of the conductor.
b) The description of the Town Loop West Side concludes that it is capable of carrying the Town peak load but goes on to say at line 11 that it still includes about 800 m of #2 Copper conductor. What is the significance of this statement? Is this conductor also undersized and needing replacement?
c) The "North" line is described as a 39 km radial 26.4 kV distribution line from the Main Substation to three embedded hydro electric generating plants. Are there any customers served from this line or is it strictly a means of getting generation into the system?
d) Should the generation owner pay for all or part of the proposed line upgrade if the line is used solely for incorporating generation?
e) What testing has the applicant conducted to determine that the #2 copper conductor on the North line is "deteriorating"? Please provide any test results, studies or analysis.

RESPONSE:

a) The Town's peak load this past summer was 14 MW or 340 Amps. The undersized conductor on the town Loop East Side is 2/0 ACSR, rated at 270 Amps. The conductor size was incorrectly stated as #1 Copper in the Application.

b) The statement in question was incorrect, as the #2 copper conductor was upgraded several years ago. The existing conductor on the Town Loop West Side is 266 ACSR, which is capable of carrying the Town load and does not require upgrading.

c) This legacy distribution line was initially extended in the 1938 to 1940 period as part of the integrated power system of Granite Power Inc. A similar comparison on the system was the distribution extension of the West Line connecting generation at Kingston Mills. The route and location of the West Line followed government highway rights-of-ways providing for customer connection and system expansion. The North Line travelled due North going off road and cross country. This location provided less opportunity for customer connection due to its remote location. The subsequent establishment of EOP's service territory limiting customer expansion North to the 401 further limits opportunity for customer connection. Although there are currently no other customers served from this line, the maintenance and capital investments associated with the North Line have always been charged to distribution and the line has been treated as a distribution asset.

The three embedded hydro electric generating plants, Brewers Mills, Jones Falls and Washburn are recognized customers as defined by the OEB Distribution System Code.

d) No, see answer to part c).

e) The statement in the Application should have stated that the pole line is deteriorating as a result of its age. This has been determined on the basis of visual inspections.

INTERROGATORY # 4

Ref: Exhibit 2, Tab 1, Schedule 1, App. A, page 4 of 7

Line 5 of this schedule refers to the new Main Station as having transformation equipment suitable for 27.6/16.0 kV supply. Please explain how the station can supply both the present 26.4 kV delta system and the proposed 27.6/16 kV Wye system.

RESPONSE:

The new transformer purchased for the new Main Station was designed to provide secondary voltage of 27.6/16 kV grounded-wye and also has an On-Load Tap Changer that facilitates secondary voltage regulation. At present, the neutral of this transformer is grounded in the station but is not extended out to the lines. This effectively maintains a three-wire delta system on the existing feeders. The transformer tap changer is set to regulate at approximately 4% lower than its design voltage, effectively supplying voltage of 26.4 kV.

When the distribution system is converted in the future to 27.6Y/16 kV, the system neutral will be extended out of the station to form part of the distribution feeders and provide a four-wire grounded-wye system. The transformer tap changer will then be set to provide a nominal voltage of 27.6 kV.

INTERROGATORY # 5

Ref: Exhibit 2, Tab 1, Schedule 1, App. A, page 4 of 7

Lines 13 to 16 describe the need for more 4.16 kV interties in the downtown area.

a) What is the peak load in the downtown area served from the Gananoque and Herbert Street Stations?
b) How many 4.16 kV interties presently exist and what are their load transfer capacities?
c) How many additional interties are required to supply the full load of the Gananoque or Herbert Street substations?

RESPONSE:

a) The approximate peak load in the downtown area served by the Gananoque and Herbert Street Substations is 9.5 MW.

b) At present there are 3 interties with a total load transfer capacity of approximately 2.2 MW.

c) To supply the full load of the Gananoque or Herbert Street substations will require the addition of one intertie and the reinforcement of two existing interties.

INTERROGATORY # 6

Ref: Exhibit 2, Tab 1, Schedule 1, App. A, page 4 of 7
Lines 18 to 20 describe the need for SCADA at the Main Substation.

a) Does CNPI currently have any SCADA system in operation?
b) Does CNPI have a 24 hour control room operation?
c) How much does CNPI expect to spend on a SCADA system?

RESPONSE:

a) There is currently no SCADA system in operation in Gananoque. CNPI has SCADA systems in operation in Fort Erie and Port Colborne and CNPI affiliate Cornwall Electric operates a SCADA system in Cornwall.

b) No, CNPI does not have a 24-hour control room operation.

c) CNPI has plans to connect the Main Substation to a SCADA system. The estimated cost of implementing SCADA at the Main Substation is $30,000.

INTERROGATORY # 7

Reference: Exhibit 2, Tab 3, Schedule 1, App. A

This schedule describes distribution system capital projects.

a) Page 6 of the schedule describes the Main station having one the 20 MVA transformer previously at the Thermal station. Is this transformer capable of supplying 27.6/16 kV Wye distribution?
b) If not, does CNPI plan to purchase a second 27.6/16 kV transformer when the distribution system is converted to that operating voltage?
c) If yes, how much will that transformer cost and when will it be procured?

RESPONSE:

a) This transformer is not presently capable of supplying 27.6/16 kV wye distribution.

b) CNPI plans to purchase a grounding transformer that will operate in conjunction with the 20 MVA transformer to supply the 4-wire 27.6/16 kV grounded-wye system. The existing 20 MVA transformer can then continue to operate until the end of its useful life. However, should the 20 MVA transformer reach the end of its useful life prior to the implementation of the 27.6/16 kV wye system, then a replacement transformer designed to provide 27.6/16 kV wye voltage would need to be purchased. This would obviate the need for the grounding transformer.

c) The estimated cost of the grounding transformer is $100,000. If CNPI is required to purchase a new 27.6/16 kV replacement transformer, the estimated cost is $700,000. CNPI plans to implement a 27.6/16 kV wye system only when new industrial load is connected to the system. Large new loads will be connected at 27.6/16 kV wye and the rest of the system would subsequently be converted in stages. Until such new industrial load materializes, CNPI plans to continue to operate the 26.4 kV delta system.

INTERROGATORY # 8

Ref: Exhibit 2, Tab 3, Schedule 1, App. A

Page 9 of the schedule describes planned upgrades to the 4.16 kV system.

a) What is the schedule for converting the system in the downtown area to 27.6/16 kV distribution?
b) Will the proposed upgrades to the 4.16 kV system be constructed to 27.6/16 kV standards in anticipation of the conversion?
c) Page 10 describes the purchase of distribution transformers. Will these be dual voltage transformers capable of supplying 16 kV distribution?

RESPONSE:

a) There are no plans or schedule to convert the downtown area to 27.6/16 kV distribution. The upgrade projects referred to on Page 9 are intended to increase line capacity but maintain the 4.16 kV voltage class.

b) As there is no planned conversion, the proposed upgrades will be constructed to 4.16/2.4 kV standards.

c) As there is no planned conversion, the distribution transformers will be capable of supplying only 2.4 kV distribution.

INTERROGATORY # 9

Ref: Exhibit 4, Tab 1, Schedule 1

Page 3 of this schedule describes the IT strategy of developing in house resources to support the IT infrastructure.

a) How many employees does CNPI currently have in its IT department?
b) How many employees does CNPI expect to ultimately need to support its IT activities?
c) What was the cost of outsourcing this function in the past?
d) What analysis did CNPI do to arrive at the decision to resource IT needs in house rather than contract them?

RESPONSE:

a) The CNPI IT department currently consists of 5 employees (4 staff members and 1 manager). The breakdown of employees is as follows:
   - IT Manager
   - Senior Systems Administrator
   - Senior Systems Analyst
   - Programmer/Analyst
   - IT Technician III

b) CNPI reviews the staffing needs on a periodic basis as part of its succession planning and to ensure that they align with the strategic goals of the organization. CNPI expects that based on current assumptions, it will need approximately 5 – 6 employees to support its IT needs until the end of 2010.

c) The IT function has never been fully outsourced and, given the risks associated with complete outsourcing, it is unlikely that it will be fully outsourced. One risk of complete outsourcing is the difficulty in gaining a reasonable assurance that complex regulatory requirements involving a change to the IT system can be carried out on a timely basis. CNPI has outsourced portions of the IT function. For example, CNPI has outsourced firewall management in the past. Based on an analysis of the cost of contracting out firewall management, CNPI determined that in-house IT staff provides this function at a lower cost. Accordingly, firewall management is now carried out in-house

d) Please see response to item c) above.

INTERROGATORY # 10

Ref: Exhibit 4, Tab 1, Schedule 1

Page 3 of this schedule describes the Regulatory strategy of developing in house resources to support Regulatory functions.

a) How many employees does CNPI currently have in its Regulatory department?
b) Is CNPI contemplating increasing staffing in this department? If so please provide details.
c) Does CNPI share regulatory staff and expenses with its other distribution companies? If so, please describe the cost sharing formula used.

RESPONSE:

a) CNPI currently has one employee in its Regulatory department.

b) CNPI has not contemplated increasing its staff in this department for the bridge or test year.

c) As a preamble to this response, it should be noted that CNPI, Canadian Niagara Power Inc., is a single corporate entity. It has a single distribution licence, ED-2002-0572, which includes its distribution operations in Fort Erie, Port Colborne and Gananoque (Eastern Ontario Power being the brand in Gananoque). In addition, CNPI has a transmission licence, ET-2003-0073, and operates transmission in Fort Erie. CNPI is a subsidiary of FortisOntario. Cornwall Electric, the licenced distributor in Cornwall, ED-2005-0405, is also a subsidiary of FortisOntario.

   The Regulatory staff of one, employed by CNPI, is allocated to CNPI's three distribution operating areas, the transmission business, Cornwall Electric and FortisOntario. This allocation is described in the BDR Report, Study of Affiliate Service Costs and Cost Allocation, found in Exhibit 4, Tab 2, Schedule 4, Appendix B.

On a full time equivalent basis, 63% is allocated to the three CNPI distribution business units in equal shares, and the remaining 37% is allocated to FortisOntario, Cornwall Electric and CNPI – Transmission business units.

INTERROGATORY # 11

Ref: Exhibit 4, Tab 2, Schedule 4, App. A

This appendix contains a copy of the Services agreement with Cornwall Electric:

a) Article 2.01 specifies the fees for service and cost mechanism including a provision for a "reasonable rate of return" defined as the "higher of the Utility's approved rate of return or the bank prime rate". What was the actual rate of return paid to Cornwall electric in its fees billings to CNPI for the historical years and what is the expected rate or return for the bridge and test years?

b) What is the rationale for providing a profit to Cornwall Electric based on rate of return considerations?

c) Given that many of the utility's customary functions appear to be carried out by Cornwall Electric, would it be more efficient to simply merge the two companies into one? Why or why not?

d) Article 2.02 refers to extraordinary expenses that will be reimbursed to Cornwall Electric.

   i) What is included in extraordinary expenses?
   ii) Has CNPI paid extraordinary expenses to Cornwall Electric in any of the historical or bridge years?
   iii) How much was paid and for what?
   iv) Does CNPI anticipate paying any extraordinary expenses in the test year?
   v) If yes, how much and for what?

RESPONSE:

a) There are direct charges for services provided by affiliates to CNPI – Eastern Ontario Power for customer service, operations and maintenance under the Services Agreements, which are based upon actual time charged (See Exhibit 4, Tab 2, Schedule 5, Appendix A, Charges to O&M). When Cornwall charges CNPI for services, it does so based on fully loaded cost only. When services are provided to affiliates and for the purpose of costing services to CNPI, the fully loaded cost utilizing service/cost based pricing has been charged for such services. Accordingly, the "reasonable rate of return" has not been calculated or applied.

b) Not applicable. See response to Interrogatory #11 a) above.

c) While certain functions of the utility are carried out by Cornwall Electric, a number of other customary functions are carried out by CNPI. Services can be provided to affiliates in accordance with the Affiliates Relationship Code. In addition, Cornwall Electric is isolated from the IESO-controlled grid and operates under a different regulatory model pursuant to exemptions granted under its distribution licence. For these reasons, there is no commercial purpose for a merger of the two companies.

d) There have been no extraordinary expenses incurred by Cornwall Electric pursuant to the Services Agreement, which are being recovered in this rate application. Further, CNPI has not paid extraordinary expenses to Cornwall Electric in any of the historical or bridge years. CNPI does not anticipate paying extraordinary expenses to Cornwall Electric in the test year.

INTERROGATORY # 12

Ref: Exhibit 4, Tab 2, Schedule 5, App. A

This appendix contains details of compensation forming part of the revenue requirement of the utility. Executive compensation and benefits costs have been omitted. Please supply the missing information or provide the reason for omitting it.

RESPONSE:

Please note that Executive compensation and benefits do form part of CNPI-Eastern Ontario Power's revenue requirement, and the costs have been included in Appendix A.

Pursuant to the 2006 Electricity Distribution Rate Handbook, CNPI-Eastern Ontario Power applied the following guideline:

"Note: For an applicant with fewer than three employees, reporting of employee compensation under this section is not required. In cases where there are three or fewer, full-time equivalents (FTE's) in any category, the applicant may aggregate this category with the category to which it is most closely related. This higher level of aggregation may be continued, if required, to ensure that no category contains three or fewer, FTE's." (2006 Electricity Distribution Rate Handbook, Schedule 6-4: Employee Compensation, pg 48)

Based on the fact that there are fewer then three Executive FTE's in CNPI-EOP, the compensation and benefit costs for the Executive category have been aggregated with the Management category. Accordingly, this information is included in Exhibit 4, Tab 2, Schedule 5, Appendix A.

INTERROGATORY # 1

Ref: Exhibit 1, Tab 2, Schedule 1, page 14

Lines 14-23 describe the Applicant's proposal to harmonize rates between the Fort Erie utility and the Gananoque utility.

a) What is the rationale for rate harmonization if the two utilities are operated as separate entities and are geographically remote from each other?
b) Does CNPI have any plans to merge its distribution utilities into one distribution company?

RESPONSE:

a) CNPI – Fort Erie and CNPI – Gananoque are two operating areas with a single distribution licence, ED-2002-0572, and are business units within the single corporate entity of CNPI. Harmonization of distribution rates will reduce the cost burden of financial and regulating reporting, regulatory compliance and rate setting.

   Though the areas are geographically separate from each other, they operated as a single corporate entity; CNPI, and have a common management team.

b) The distribution operating areas in Fort Erie, Port Colborne and Gananoque are currently operated in a single distribution corporation; CNPI.

INTERROGATORY # 2

Ref: Exhibit 2, Tab 1, Schedule 1, App. A
Exhibit 2, Tab 3, Schedule 1, App. A

Page 2 of the first reference and pages 5-7 of the second reference describe ongoing work to convert existing 4.8 kV delta distribution to 8.3/4.8 kV wye distribution. Does the utility have an overall plan which is guiding the conversion program? If yes, please provide details expected time to complete and estimated cost to complete.

RESPONSE:

The CNPI plan for converting the remaining 4.8 kV delta load in Fort Erie is as follows:

- Phase 1: (in progress): convert loads formerly supplied from Station 13. This stage is expected to cost $2.5 million and take 5 years to complete.
- Phase 2: convert loads supplied from Station 15. This is expected to take 5 years and cost $2.5 million.
- Phase 3: convert loads supplied from Station 12. This is expected to cost $5 million and take 10 years to complete.

The costs cited above are for converting distribution lines and loads only, and are exclusive of the cost of new substations that will be constructed in the future. In total, the conversion program is expected to cost $10 million in future capital investment. At the present conversion rate, the entire system will be converted over the next 20 years.

INTERROGATORY # 3

Ref: Exhibit 2, Tab 1, Schedule 1, App. A

Page 4-5 of the first reference describes CNPI's use of ratio banks.

a) Does CNPI have a policy of limiting the use of these installations given their disadvantages?
b) Does CNPI have a plan to replace "rabbits" by building substations to provide the 8.3/4.8 kV distribution voltage? Please provide details.

RESPONSE:

a) Yes, CNPI does limit the use of these installations. Most ratio bank installations have been installed as an interim measure to facilitate voltage conversion efforts. In addition to this objective, certain ratio banks were installed to offload the aging Station 13. Some ratio banks were installed as an economic means of serving rural loads.

b) CNPI does plan to eventually phase out most "Ratio Banks" or "Rabbits" by serving loads from 8.3Y/4.8 kV substations. Most Rabbits presently on the system will eventually be replaced by feeders supplied from the existing Station 19 in Ridgeway. Where economically justified, loads served by certain Ratio Banks will be converted to 34.5Y/19 kV voltage.

   CNPI does plan to construct more 8.3Y/4.8 kV substations in the future to convert the remaining 4.8 kV delta load and to provide alternate sources for loads supplied from Station 19. These substations will serve loads presently supplied from some Ratio Banks. In rare instances, Ratio Banks may continue to serve isolated rural loads. However, the intent is to minimize such installations.

INTERROGATORY # 4

Ref: Exhibit 2, Tab 1, Schedule 1, App. C

Page 6 describes CNPI's IT strategy of using in house staff for IT support functions. At line 4 the statement is made that "*CNPI will continue to utilize lower cost in-house SAP trained IT staff in conjunction with external backup from SAP consultants as required*". Has CNP conducted any studies or analyses to confirm that in house IT staff are lower cost overall to contracting the support service out? If yes, please provide details of the analysis. If no, what is the basis for concluding that external contract resources are more expensive than in house resources?

RESPONSE:

Yes. External IT consultants have typically charged $1,600 per day, compared with an internal fully loaded cost of $368 per day for in-house IT personnel. CNPI also analyzed the cost of contracting out firewall management, and determined that in-house IT staff are lower cost.

A detailed discussion of fully loaded labour rates is found in the response for SEC-06.

INTERROGATORY # 5

Ref: Exhibit 2, Tab 3, Schedule 1, App. A

Page 9 of the appendix describes station 12 feeder rebuilds.

a) How old are the existing poles, hardware and aerial cable?
b) How will the rebuilt lines differ from the existing?
c) If egress is available at 4 points from the station, should we conclude that the 12 circuits are carried on 4 multi circuit pole lines?
d) If the answer to c) above is Yes, why is a three circuit pole line a problem requiring aerial cable?

RESPONSE:

a) The existing poles, hardware, and aerial cable are more than 30 years old.

b) The rebuilt lines will differ from the existing by being constructed to modern standards with adequate clearance between conductors. CNPI is considering using open-wire construction for the rebuilt line and does not consider aerial cable to be a viable option because of performance issues with this type of construction.

c) Yes, the 12 circuits are carried on 4 multiple-circuit lines.

d) CNPI does not plan to rebuild the line using aerial cable, and is considering other options including open-wire construction.

INTERROGATORY # 6

Ref: Exhibit 2, Tab 3, Schedule 1, App. A

Page 10 of the appendix describes the proposed relocation of the 18L10 feeder from right-of-way to road allowance. Reference is made to reliability and access problems.

a) If vegetation is growing into the conductors, why has the utility not just removed it?
b) How many interruptions in the historical years and bridge year to date have occurred on this line section?
c) Why is an abandoned railway line a difficult area to access for maintenance and repairs?

RESPONSE:

a) The 18L10 feeder serves significant commercial load in Fort Erie, so outages on this feeder adversely affect the business sector. The section of feeder in question runs along an old railway right-of-way. Road access to the right-of-way is limited, and at some times during the year soggy ground conditions make it extremely difficult for vehicular traffic to drive the right-of-way and access the line. This causes severe challenges to vegetation management and line maintenance activities.

   Under the circumstances, CNPI performs reasonable and appropriate vegetation management and line maintenance activities on this line section. However, because the area is heavily treed, even if proper clearances are maintained there is still a risk of trees falling into the line. This risk cannot be avoided without chopping down numerous trees in the area, which is impractical.

b) Excluding outages that occurred during the October 2006 Natural Disaster, in years 2006, 2007, and 2008 year to date there has been one feeder interruption each year due to problems along this line section. In addition, during the October 2006 Natural Disaster there were outages due to trees falling onto this line section.

Notwithstanding the outage statistics, it is difficult to access this line for maintenance and repairs because road access is limited to this heavily treed trail area. This section of line is over thirty years old and some poles and equipment are over fifty years old. The line is in a deteriorating condition and is due for replacement. It is more reasonable and appropriate to invest in a new line along a roadway where the line would be readily accessible rather than replacing the line in its existing location.

c) Roadway access to the right-of-way is limited, and access to the line can be further hampered by soggy ground conditions.

INTERROGATORY # 7

Ref: Exhibit 2, Tab 3, Schedule 1, App. A

Pages 12-13 of the appendix describes the utility's proposals to replace transportation and work equipment.

a) What criteria does the utility use to replace equipment? Please provide details of the evaluation criteria.
b) What is the utility's policy for disposing of aging equipment?
c) How are the proceeds of disposition accounted for?

RESPONSE:

a) CNPI has a vehicle replacement cycle that is updated annually based on assessments of future operational needs and the condition of existing vehicles. CNPI has targeted time periods for vehicle replacement, though vehicles may be retained for longer periods depending on their condition. The target replacement periods for different classes of vehicle are as follows:

- Line trucks: 10 years.
- Pickup trucks: 5 years.
- Cargo vans: 8 years.
- Pool vehicles: 180,000 km.

(b) Retired vehicles are generally sold at an auction.

(c) The proceeds of disposition net of the residual cost of the asset is recorded in OEB account 4355 and classified on the income statement with other income/deductions.

INTERROGATORY # 8

Ref: Exhibit 2, Tab 3, Schedule 1, App. A

Pages 15-16 of the Appendix describe plans to upgrade and extend SCADA coverage on the distribution system. Does the utility have an overall plan for extending SCADA coverage? If yes, what is the schedule for completion and the estimated costs to complete the SCADA system? If no, how does the utility decide what investments to make in its SCADA on a year by year basis?

RESPONSE:

The base SCADA system was installed some years ago and all CNPI substations in Fort Erie are already remotely monitored and controlled via SCADA. The plans in Appendix A refer to smaller-scale projects to extend SCADA to selected new components added to the distribution system or upgraded components already on the system. Any new substations would naturally be designed for SCADA monitoring and control, and other components that may be added to SCADA could include reclosers, regulator banks, capacitor banks, and strategically located loadbreak switches and fault indicators. In addition, CNPI plans to maximize the monitoring capability of its SCADA system by extending monitoring to components such as microprocessor-based relays to allow for speedy, remote relay interrogation and event data retrieval.

The expansion and evolution of the CNPI SCADA system is an ongoing program. Deciding where annual SCADA investments should be made is based upon evaluating which components would improve operational effectiveness by being SCADA-monitored and/or controlled. For example, extending SCADA to a line recloser to allow remote monitoring and control would improve operational effectiveness including: labour savings from less manual switching, the ability to restore power more quickly in outage situations, and access to real-time loading information and event data to support operational and system planning activities.

As CNPI already has a SCADA system in place, adding new components to SCADA entails relatively low incremental costs. Most modern equipment is already supplied with

SCADA-ready controls. Depending on where components are physically located and the communications infrastructure that must be installed for SCADA capability, costs to automate a component could range from $2,000 to $15,000.

INTERROGATORY # 9

Ref: Exhibit 2, Tab 3, Schedule 1, App. A

Page 17 describes the utility's plans to underground plant in the Town of Fort Erie. Mention is made of a capital contribution from the Town for $700,000 to support the project. What is the total capital cost of undergrounding the system? What is the schedule for completion? How was the capital contribution amount arrived at?

RESPONSE:

The referenced projects are to place underground distribution systems along Garrison Road and Queen Street in downtown Fort Erie. The total capital cost of these two projects is currently estimated to be $850,000. The Queen Street project is scheduled to be completed by the end of 2008, and the Garrison Road project by June 2009.

The cost of the Queen Street project is estimated at $350,000. Because this is a "beautification" project, the Town is contributing 100% of the cost.

The Garrison Road project is estimated at $500,000, and the Town is contributing $350,000 of this amount. This project is a "road relocation" project, so the Capital Contribution amount was determined in accordance with the guidelines laid out in the OEB Distribution System Code, Section 3.5.1, "Relocating Plant for Road Works". Under these guidelines, CNPI contributes 50% of the labour cost and 100% of the material cost of relocating its existing plant. CNPI's contribution amount was calculated to be $150,000.

INTERROGATORY # 10

Ref: Exhibit 4, Tab 2, Schedule 3, App. A

Page 1 of this appendix provides analysis of increased costs in the control room function at the utility. Increased costs over the 2006 Board approved costs for this function are attributed to transfer of some functions previously performed by line staff to control room staff.

a) Please provide details of what these transferred functions consisted of.
b) Is CNPI's practice of staffing its control room on 15 hour x 5 day basis typical for a utility of its customer size? Please provide any analysis or studies that the utility has conducted to compare to other similar utilities.
c) Does the utility run an evening line crew shift or are trouble calls handled by on call staff?
d) If the utility does not run an evening line crew shift, what work does the control room operator have during the evening shift?

RESPONSE:

a) The centralized system control function based in Fort Erie assumes responsibility for the monitoring and control of all CNPI distribution systems in the Niagara Region. This responsibility includes tasks such as monitoring and operating the SCADA system, preparing switching orders and directing switching operations, responding to emergencies and overseeing restoration efforts, administering work protection and all aspects of the Work Protection Code, handling trouble calls, dispatching crews, preparing reports, preparing contingency plans, issuing switching device nomenclature, liaising with external entities such as Hydro One, and coordinating with internal Customer Service staff.

   Previously, line staff performed these System Control activities only at very basic levels. This transfer of responsibility allows line staff to focus on their core line maintenance and construction activities. Having a centralized system control function based in Fort Erie allows personnel to focus on System Control activities and develop a thorough knowledge of the overall system. Operators also have access to real-time SCADA information and detailed mapping information that enables the operator to quickly identify system problems and co-ordinate a response. Therefore, having a centralized function focused on overseeing system operations enhances personnel safety and system reliability and facilitates outage response.

b) The CNPI centralized system control function oversees system operations for CNPI-Transmission, CNPI-Fort Erie Distribution, and CNPI-Port Colborne Distribution. CNPI has not undertaken any formal analysis or studies to compare other utilities; however, it is aware that centralized day and evening hours system control function is common practice in a number of Ontario utilities.

c) CNPI does not run an evening line crew shift and trouble calls are handled by on-call linemen and with the support of the centralized system control function.

d) During the evening shift the control room operator performs the same System Control activities outlined in our response to a) above. During outage situations that occur during the evening shift, the operator continues to liase with linemen and perform direct restoration activities. In addition, there are certain work planning activities that are carried out for the following day (i.e. preparation of switching procedures).

INTERROGATORY # 11

Ref: Exhibit 4, Tab 2, Schedule 3, App. A

Page 2 of this appendix provides explanation for increased costs Distribution Station Equipment labour. Mention is made of redeploying electricians from the Rankine Generating station to distribution functions when the generating station was laid up.

a) How many staff were transferred from the Generating station to distribution work?
b) Would the utility have hired additional electricians to work on its substations had the generating station continued in service?
c) Are there plans to restart the generating station and transfer electrical staff from distribution work back to generating station maintenance?

RESPONSE:

a) The increased costs associated with Distribution Station Equipment labour is explained by the assignment of additional electricians. Three electricians and their hours were reassigned from the generating station to distribution. The electricians had been originally hired for distribution work and then assigned to also perform generation work and subsequently back to distribution work.

b) Yes, CNPI would have hired additional electricians to perform required substation maintenance.

c) No, there are no plans to restart the generating station.

INTERROGATORY # 12

Ref: Exhibit 4, Tab 2, Schedule 3, App. C

Page 3 of the appendix describes increased costs in Employee Pensions and Benefits. Mention is made of an increase in Post Retirement Benefit costs of $196,913.

a) Why have benefit costs increased so much?

b) What post retirement benefits does the utility provide retirees?

c) Are post retirement benefits fully funded by the utility or do retiring employees make a contribution?

d) Are post retirement benefits time limited or otherwise capped?

RESPONSE:

a) There was an increase in post retirement benefit costs from the 2006 Board Approved to the 2006 Actual because of a decrease in the discount rate and a correction to the allocation of post retirement benefits expense between FortisOntario and CNPI.

During the period 2004 to 2006 the discount rate used to calculate the accrued benefit obligation ("ABO") decreased from 6.25% to 5.00% resulting in an actuarial loss and an increase in the post retirement benefit expense. CNPI's post retirement benefit expense amount and discount rate used to calculate the ABO is determined by Mercer's Human Resource Consulting (Mercer's).

In 2006, an error was discovered and corrected in which Mercer's were incorrectly allocating post retirement benefit expense of CNPI employees to FortisOntario. The correction resulted in a prospective increase in the CNPI post retirement benefit expense.

b) Current retirees have health and dental benefits until death. The retiree health and dental benefits are aligned with the benefits for current employees at the date of retirement.

c) Retirement benefit premiums are currently fully funded by the utility. There are some co-pay requirements such as a dispensing fee cap, ceilings on coverage for eye wear, paramedical services and dental procedures.

d) Retired employees who were hired prior to June 2003 have post retirement benefits until death. Retirees who have been hired after June 1, 2003, will have health and dental retiree benefits from the date of retirement to the age of 65, provided that they have a minimum of 20 years of continuous service with the company.

INTERROGATORY # 13

Ref: Exhibit 4, Tab 2, Schedule 5, App. A

This appendix contains details of compensation forming part of the revenue requirement of the utility. Executive compensation and benefits costs have been omitted. Please supply the missing information or provide the reason for omitting it.

RESPONSE:

Please note that Executive compensation and benefits do form part of CNPI-Fort Erie's revenue requirement, and the costs have been included in Appendix A.

Pursuant to the 2006 Electricity Distribution Rate Handbook, CNPI-Fort Erie applied the following guideline:

"Note: For an applicant with fewer than three employees, reporting of employee compensation under this section is not required. In cases where there are three or fewer, full-time equivalents (FTE's) in any category, the applicant may aggregate this category with the category to which it is most closely related. This higher level of aggregation may be continued, if required, to ensure that no category contains three or fewer, FTE's." (2006 Electricity Distribution Rate Handbook, Schedule 6-4: Employee Compensation, pg 48)

Based on the fact that there are fewer then three Executive FTE's in CNPI-Fort Erie, the compensation and benefit costs for the Executive category have been aggregated with the Management category. Accordingly, this information is included in Exhibit 4, Tab 2, Schedule 5, Appendix A.

INTERROGATORY # 1

Ref: Exhibit 2, Tab 1, Schedule 1, App. A

Page 2 of the appendix describes the distribution system.

a) Why does the utility transform the supply from Hydro One to a less efficient voltage rather than distribute power at 27.6/16 kV?
b) What are the utility's line and transformation losses?
c) Has the utility conducted any studies to evaluate the cost efficiencies of converting to the higher distribution voltage and abandoning its low voltage substations and ratio banks? If yes, please provide details of the analysis.

RESPONSE:

a) Distribution of electricity at the lower voltage of 4.16/2.4 kV is a common legacy voltage found throughout Ontario. The evolution of Ontario's electricity distribution system has yielded higher level distribution voltages to adequately serve larger loads. In Port Colborne, like other jurisdictions, there has been an orderly transition from one distribution configuration to the next.

   It is an accepted reality that to supply a given load in kilowatts, a lower voltage system will carry higher amperage and therefore incur higher losses since losses are a function of the square of the amperage. However the trade off is that these lower voltage systems are generally less expensive to construct and maintain.

b) The forecasted line losses for CNPI – Port Colborne is 1.0382.

c) No, CNPI – Port Colborne has not conducted specific studies to evaluate the cost efficiencies of converting to the higher distribution voltage and abandoning its low voltage substations and ratio banks. Experience has shown that such an undertaking would likely be very expensive and place considerable pressures on distribution rates.

INTERROGATORY # 2

Ref: Exhibit 2, Tab 1, Schedule 1, App. A

Page 3 of the appendix describes the SCADA system employed to monitor the distribution system. Has the utility benchmarked its operations with similar sized utilities to determine whether its control room and SCADA expenditures are comparable? If yes, please provide details.

RESPONSE:

CNPI-PC has not compared its control room and SCADA expenditures with those of similar-sized utilities. Such comparisons are difficult to make because:

- Different utilities have deployed SCADA systems to varying degrees, ranging from no SCADA system to fully automated systems, with various configurations of monitoring and/or control in between.
- The CNPI control room is not solely dedicated to Port Colborne, but is a centralized function that oversees system operations for CNPI-Transmission, CNPI-Fort Erie, and CNPI - Port Colborne. The efficiencies inherent in a centralized control room function are generally accepted, but utilities of a similar size to CNPI - Port Colborne may utilize various models.
- Any cost comparisons should also take into account the operational efficiencies gained by deploying SCADA systems connected to a centralized system control function. These include productivity gains from the remote monitoring and control of equipment and the benefits derived from access to real-time and historical system data. The latter also enhances system planning and operational activities, including outage response.
- Whether or not a similar-sized utility has a control room or SCADA system, activities such as switching, isolation, and work protection are part of typical daily utility operations. In the case of utilities with no control room, there is a productivity loss associated with having to manually operate field devices and with linemen or other personnel preparing switching orders, work protection, and performing other typical system control activities.

CNPI – Port Colborne utilizes a progressive approach to system control and SCADA development that promotes safe and reliable system operation while achieving operational efficiencies. In the CNPI model of a centralized control room, efficiencies are achieved because personnel oversee operations for different territories and systems. Having personnel dedicated to system control allows them to develop a thorough knowledge of the various systems and facilitates centralized recording of system changes. CNPI control room operators have access to real-time SCADA information and detailed system maps that enable them to quickly identify system problems and coordinate trouble response.

INTERROGATORY # 3

Ref: Exhibit 2, Tab 3, Schedule 1, App. A

Page 6 describes an upgrade to the 4.16 kV circuit on Killally Street East.

a) What specifically does the upgrade consist of? What specific benefits will be realized from the upgrade?
b) Are the 4.16 kV feeders from the distribution station radial, looped, or networked?
c) If radial, how will upgrading individual feeder conductors increase transfer capability between feeders?
d) The 2008 budget for this project is $150,000 and the 2009 budget is $200,000. What is the estimated total cost of the project? What is the scheduled completion date?

RESPONSE:

a) The upgrade consists of installing new poles and larger size overhead conductors to replace original plant that is over thirty years old.

   This project is designed to upgrade feeder capacity on all distribution feeders supplied from Killally Substation. One specific benefit that will be realized is the increased capacity will allow feeders to carry loads normally served by other feeders. This will improve service levels to customers by reducing the possibility of outages for planned maintenance and providing alternate paths for restoration during emergencies.

   Another benefit that will be realized is the new poles, conductors, and accessories will replace original facilities that are more than thirty years old. This improvement in asset condition will result in decreased probability of equipment failure and customer outages.

b) The terms “looped” and “networked” vary in definition from utility to utility. CNPI-Port Colborne describes the Killally DS feeders as radial with Normally Open tie points between feeders. Some utilities would refer to this as an “open-loop” configuration. Each feeder typically has more than one tie point along its length.

This allows significant operational flexibility for transferring loads between feeders under planned or emergency conditions.

c) As described above, the feeders are radial with Normally Open tie points between feeders. Loads are transferred between feeders by closing tie points and opening other switches at appropriate locations. Thus, if load is to be transferred from feeder A to feeder B, then feeder B must be of sufficient capacity to carry the additional load.

d) The estimated total cost of the project is $350,000. The scheduled completion date is September 2009.

INTERROGATORY # 4

Ref: Exhibit 2, Tab 3, Schedule 1, App. A

Reference is made on Page 6 to the Empire Road upgrade which appears to be a single to three phase conversion on the 16 kV feeder and a betterment to the underbuilt 4.16 kV feeder. These improvements are said to be associated with providing “adequate supplies to and from Beach Road DS”. The 2008 budget for the project is $75,000 and the 2009 budget is $75,000.

a) Please explain the need for these improvements in more detail.
b) What is the total estimated project cost and when is it scheduled to be complete?

RESPONSE:

a) The improvement is required because the Beach Road DS requires a three-phase, 27.6Y/16 kV supply. Therefore, the existing single-phase line must be upgraded to the three-phase line. New conductors are being installed for the 27.6Y/16 kV line; however, most of the conductor on the 4.16 kV underbuild will remain in service as it is of adequate size for loading in the area. There will be some 4.16 kV feeder upgrading and reconfiguring on Beach Road close to the site of the new DS to facilitate supplies to Sherkston Shores and to other CNPI-Port Colborne loads.

b) The total estimated project cost is $150,000 and it is scheduled for completion in April 2009.

INTERROGATORY # 5

Ref: Exhibit 2, Tab 3, Schedule 1, App. A

The Royal Road subdivision upgrade is described as costing $100k in 2008.

a) What is the total project cost?
b) What kind of cable is presently in the ground and what kind of cable is going to be installed in the rebuild?

RESPONSE:

a) The total project cost is estimated at $350,000.

b) The existing cable is direct-buried 1/0 Aluminium, XLPE-insulated, non-jacketed concentric neutral cable.

The new cable will be installed in conduit and will be 1/0 Aluminium, XLPE-insulated, jacketed concentric neutral cable.

INTERROGATORY # 6

Ref: Exhibit 2, Tab 3, Schedule 1, App. A

Reclosers were installed on 27.6 kV feeders in 2007 and more are budgeted for 2009. What is the utility's policy for the number of recloser installations in series on a feeder?

RESPONSE:

CNPI - Port Colborne (CNPI-PC) does not have a formal policy for installing multiple reclosers in series on a feeder and to date has not undertaken such installations. CNPI–PC's current practice is to install reclosers on major branches off long 27.6 kV feeders to protect the main portion of the feeder from faults occurring on the branches. If a fault occurs on a section of feeder protected by the recloser, then the majority of customers on the feeder are unaffected by an interruption that may be caused by the fault. A trip on a recloser also facilitates speedier fault location and isolation, as it is evident what branch of the feeder the fault has occurred on.

CNPI–PC plans to continue installing reclosers on feeders in accordance with its present practice. In the future, after all major feeder branches are protected, CNPI-PC will assess the benefit of installing multiple reclosers in series on feeders to provide further sectionalisation that would reduce the number of customers affected by a fault and further improve fault location and isolation. Prior to embarking on such configurations, CNPI–PC will develop a policy for multiple reclosers in series on a feeder.

INTERROGATORY # 7

Ref: Exhibit 4, Tab 2, Schedule 5, App. A

This appendix contains details of compensation forming part of the revenue requirement of the utility. Executive compensation and benefits costs have been omitted. Please supply the missing information or provide the reason for omitting it.

RESPONSE:

Please note that Executive compensation and benefits do form part of CNPI-PC's revenue requirement, and the costs have been included in Appendix A.

Pursuant to the 2006 Electricity Distribution Rate Handbook, CNPI-Port Colborne applied the following guideline:

"Note: For an applicant with fewer than three employees, reporting of employee compensation under this section is not required. In cases where there are three or fewer, full-time equivalents (FTE's) in any category, the applicant may aggregate this category with the category to which it is most closely related. This higher level of aggregation may be continued, if required, to ensure that no category contains three or fewer, FTE's." (2006 Electricity Distribution Rate Handbook, Schedule 6-4: Employee Compensation, pg 48)

Based on the fact that there are fewer then three Executive FTE's in CNPI-Port Colborne, the compensation and benefit costs for the Executive category have been aggregated with the Management category. Accordingly, this information is included in Exhibit 4, Tab 2, Schedule 5, Appendix A.

INTERROGATORY # 1 - Updates to evidence

Interrogatories common to all three applications

a) Since the filing of the three applications, given the economic situation, has CNPI assessed the situation and identified any specific issues that have a material impact on its load and revenue forecasts and bad debt expense forecast.
b) If so, can CNPI provide the necessary evidence and an estimate of the timing of any update including necessary calculations?

RESPONSE:

a) CNPI is not aware, at this time, of any specific issues arising from the current economic situation that have a material impact on its load and revenue forecasts and bad debt expense forecast.

b) Not applicable.

INTERROGATORY # 2 - Rate Base and Capital Expenditures (excluding Smart Meters)

Interrogatories common to all three applications

Ref: Exhibit 2 – Rate Base and Capital Expenditures

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

a) the EOP service area;
b) the Fort Erie service area;
c) the Port Colborne service area; and

	2006 Actual	**2007 Actual**	**2008 Bridge**	**2009 Test**
Allowed Return on Equity (%) on the regulated rate base				
Actual Return on Equity (%) on the regulated rate base				
Retained Earnings				
Dividends paid to shareholders				
Sustaining capital expenditures (excluding smart meters)				
Development capital expenditures (excluding smart meters)				
Operations capital expenditures				
Smart Meters capital expenditures				
Other capital expenditures (please specify)				
Total capital expenditures (including smart meter meters)				
Total capital expenditures (excluding smart meter capital expenditures)				
Depreciation expense				
Construction Work in Progress				
Rate Base				
Taxes/PILs paid/forecasted				
Number of Customer Additions (total)				
- Residential				
- General Service < 50 kW				
- General Service > 50 kW, Intermediate and Large Use				
Number of Customers (total, December 31)				
- Residential				
- General Service < 50 kW				
- General Service > 50 kW, Intermediate and Large Use				

RESPONSE: See charts on following pages:

CNPI-Fort Erie

	2006 Actual	2007 Actual	2008 Bridge	2009 Test
Allowed Return on Equity (%) on the regulated rate base (1)	4.50%	4.50%	4.20%	3.63%
Actual Return on Equity (%) on the regulated rate base (2)	0.14%	0.18%	0.57%	0.37%
Retained Earnings (Deficiency)	1,789,646	2,258,216	(2,293,813)	(1,976,279)
Dividends paid to shareholders (4)	-	-	5,000,000	-
Sustaining capital expenditures (excluding smart meters)	2,929,425	2,378,684	2,314,971	2,000,669
Development capital expenditures (excluding smart meters)	23,135	1,336,908	901,973	870,288
Operations capital expenditures	637,647	487,999	437,966	663,825
Smart Meters capital expenditures				3,127,000
Other capital expenditures (please specify) IT	359,315	297,746	484,192	574,991
Total capital expenditures (including smart meter meters)	3,949,522	4,501,337	4,139,102	7,236,773
Total capital expenditures (excluding smart meter capital	3,949,522	4,501,337	4,139,102	4,109,773
Depreciation expense	1,965,950	1,862,300	1,882,884	1,987,933
Construction Work in Progress	569,786	343,370	456,423	598,068
Rate Base	35,736,393	35,731,471	36,617,852	37,463,907
Taxes/PILs paid/forecasted (3)	97,871	(1,525)	11,082	458,147
Number of Customer Additions (total)	105	163	133	134
- Residential	101	154	121	121
- General Service < 50 kW	9	2	9	10
- General Service > 50 kW, Intermediate and Large Use	(5)	7	3	3
Number of Customers (total, December 31)	15,335	15,498	15,631	15,765
- Residential	13,919	14,073	14,194	14,315
- General Service < 50 kW	1,232	1,284	1,293	1,303
- General Service > 50 kW, Intermediate and Large Use	134	141	144	147

(1) Allowed return on equity times deemed equity
(2) Earnings divided by rate base times deemed equity
(3) Based on existing rates and excludes capital taxes, 2009 based on proposed distribution rates
(4) Dividend paid to realign CNPI's combined capital structure with the OEB's deemed capital structure

CNPI-Port Colborne

	2006 Actual	2007 Actual	2008 Bridge	2009 Test
Allowed Return on Equity (%) on the regulated rate base (1)	4.50%	4.50%	4.20%	3.63%
Actual Return on Equity (%) on the regulated rate base (2)	1.39%	-0.32%	-0.31%	-0.71%
Retained Earnings (Deficiency)	(654,454)	(764,169)	(846,799)	(1,064,639)
Dividends paid to shareholders	-	-	-	-
Sustaining capital expenditures (excluding smart meters)	1,486,238	996,170	726,709	865,726
Development capital expenditures (excluding smart meters)		342,885	388,585	1,767,134
Operations capital expenditures	5,398	9,656	13,242	41,278
Smart Meters capital expenditures				1,815,000
Other capital expenditures (please specify)				
Total capital expenditures (including smart meter meters)	1,491,636	1,348,711	1,128,536	4,489,138
Total capital expenditures (excluding smart meter capital	1,491,636	1,348,711	1,128,536	2,674,138
Depreciation expense	527,528	518,695	585,188	645,216
Construction Work in Progress	124,683	25,128	890,127	143,560
Rate Base	10,059,831	11,749,472	12,255,962	13,295,618
Taxes/PILs paid/forecasted (3)	27,551	(501)	3,709	162,592
Number of Customer Additions (total)	10	14	4	26
- Residential	17	16	1	23
- General Service < 50 kW	(12)	(7)	2	2
- General Service > 50 kW, Intermediate and Large Use	5	5	1	1
Number of Customers (total, December 31)	9,145	9,159	9,163	9,189
- Residential	8,115	8,131	8,132	8,155
- General Service < 50 kW	956	949	951	953
- General Service > 50 kW, Intermediate and Large Use	74	79	80	81

(1) Allowed return on equity times deemed equity
(2) Earnings divided by rate base times deemed equity
(3) Based on existing rates and excludes capital taxes, 2009 based on proposed distribution rates

CNPI-Gananoque

	2006 Actual	2007 Actual	2008 Bridge	2009 Test
Allowed Return on Equity (%) on the regulated rate base (1)	4.50%	4.50%	4.20%	3.63%
Actual Return on Equity (%) on the regulated rate base (2)	1.49%	0.75%	0.43%	-0.36%
Retained Earnings	901,904	941,591	1,009,011	945,084
Dividends paid to shareholders	-	-	-	-
Sustaining capital expenditures (excluding smart meters)	263,119	954,942	655,283	773,818
Development capital expenditures (excluding smart meters)		1,638,937	95,506	94,083
Operations capital expenditures	1,190	204,457	216,500	
Smart Meters capital expenditures				676,000
Other capital expenditures (please specify)	-	-	-	-
Total capital expenditures (including smart meter meters)	264,309	2,798,336	967,289	1,543,901
Total capital expenditures (excluding smart meter capital	264,309	2,798,336	967,289	867,901
Depreciation expense	298,940	356,862	452,930	480,538
Construction Work in Progress	1,676,017	73,417	121,081	171,202
Rate Base	5,234,903	5,847,031	7,350,180	7,756,830
Taxes/PILs paid/forecasted (3)	14,337	(249)	2,225	94,858
Number of Customer Additions (total)	16	(1)	12	15
- Residential	2	1	9	10
- General Service < 50 kW	15	(3)	4	4
- General Service > 50 kW, Intermediate and Large Use	(1)	1	(1)	1
Number of Customers (total, December 31)	3,553	3,552	3,564	3,579
- Residential	3,099	3,100	3,109	3,119
- General Service < 50 kW	420	417	421	425
- General Service > 50 kW, Intermediate and Large Use	34	35	34	35

(1) Allowed return on equity times deemed equity
(2) Earnings divided by rate base times deemed equity
(3) Based on existing rates and excludes capital taxes, 2009 based on proposed distribution rates

INTERROGATORY # 3 – Asset Management

Interrogatories common to all three applications

Ref: Exhibit 2/Tab 1/Schedule 1/Appendix D – Asset Management

CNPI describes its asset management practice in this Appendix, common to all three applications.

a) Please describe CNPI's policies and practices for assessing the condition of its assets, and of how such reviews feed into the asset management review.
b) Does CNPI conduct an Asset Condition Assessment study?
   i) If not, please explain.
   ii) If yes, please provide a copy on CNPI's most recent Asset Condition Assessment study for each of the service areas:
      a) EOP;
      b) Fort Erie; and
      c) Port Colborne.
c) In the exhibit, CNPI states that: "It is during the five-year business forecast process that project prioritization is initially carried out. This achieves the objectives of setting the overall future annual capital and operating budgets and specifies the timing of larger capital items within the five-year forecast period." Please provide CNPI's latest five-year business forecast for annual capital budgets, indicating major capital items, the timing of these and the reasons supporting them with respect to timing/prioritization and need (e.g. reliability improvement).

RESPONSE:

(a) CNPI assesses asset condition by means of its predictive maintenance programs. These programs are designed to identify equipment deficiencies on lines or in substations that may lead to failure. CNPI predictive maintenance activities consist of visual inspections, equipment testing, and substation transformer dissolved gas analysis.

Lines

Visual inspections of lines are carried out on an annual basis, where all overhead and underground lines within selected zones are patrolled and detailed inspections carried out on equipment including poles, crossarms, guy wires, transformers (overhead and padmounted), conductors and cables, insulators, arrestors, bushings, terminations, switching devices (fused cutouts, loadbreak and disconnect switches, live-line openers, etc). Civil facilities, such as transformer pads and cable chambers, are also inspected. As a result, most overhead and underground line components are normally inspected on a three-year cycle. This conforms to the three-year cycle for urban facilities outlined in the OEB Distribution System Code, Appendix C, *Minimum Inspection Requirements*. Some areas in CNPI service territories could be considered rural, and therefore could possibly be subject to a six-year cycle based on the OEB requirements. However, CNPI applies a three-year inspection cycle to its distribution lines to ensure adequate safety and system reliability.

The results of these inspections and any identified deficiencies are recorded in a database. Deficiencies are assessed on the basis of the potential for failure and consequential impact on safety or reliability. They are then prioritized for corrective action. The first classification indicates that urgent repair or replacement is required to address an imminent failure or safety hazard, while the second indicates that the deficiency is of a minor nature and action can be deferred. Examples of priority deficiencies would be broken poles/crossarms or floating conductors, while a less critical deficiency would be a blown lightning arrestor. Patrols are carried out by line crews, which allow some critical deficiencies to be addressed during these patrols. Repairs to less critical deficiencies are typically planned so that a group of deficiencies within a given area can be addressed by a single crew in a short timeframe.

In addition to the three-year cycle inspections described above, major line equipment such as voltage regulators are inspected on a monthly basis and any deficiencies noted and corrected. Deficiencies observed outside of scheduled line patrols are also recorded and corrected. In 2009, CNPI plans to commence regular thermographic scanning as part of its predictive maintenance program. In a given year, thermographic scans will be carried out in the same zone as the visual inspections. CNPI is also investigating pole testing processes for possible future application.

Substations

Predictive maintenance is also carried out in substations, and is integral to maintaining reliability and detecting potential equipment failure. Substation equipment typically requires large investments for installation and failure of substation components can affect large numbers of customers, so detecting potential failures before they occur is key to maintaining safety and reliability. There are presently three key predictive maintenance activities performed on regular schedules in CNPI substations: visual inspections, power transformer dissolved gas analysis, and substation battery testing.

Substation inspections are essential for assessing the condition of equipment and identifying deterioration or areas where attention is required. CNPI conducts monthly inspections on its substations regardless of location. Substation buildings, fences, and electrical components (buswork, switches, insulators, batteries, transformers, ground conductors, etc.) are inspected and any deficiencies recorded. In addition, data such as relay targets, breaker counters, direct current system voltage, and power transformer gauge readings are recorded. The condition of ancillary equipment such as lighting, eyewash stations, first-aid kits, and oil spill kits is also inspected. Any deficiencies noted during inspections are recorded, reported, and prioritized for corrective action.

Dissolved gas analysis (“DGA”) is an effective tool for assessing the condition of substation transformers and identifying deterioration in transformer oil or insulation. DGA can also identify whether arcing or acid build up is occurring inside the transformer. DGA tests for the presence of dissolved gas and water in transformer insulating oil, and based on the level of gas(es) or moisture present, assesses the condition of the transformer. An important aspect of DGA is the trend analysis, which reviews the history of dissolved gas levels in the transformer.

DGA is scheduled annually on all substation transformers and oil-filled potential transformers on CNPI systems, whether in-service or spare. CNPI uses a qualified laboratory to perform the analysis, provide reports on transformer condition, and recommend any required actions if gassing is above normal levels or if acids are detected. Corrective action to deal with abnormalities is essential to prevent failure and extend the life of the transformer.

Batteries are essential substation components that provide direct current power for station protection, monitoring, and control. Battery resistance testing is undertaken on an annual basis at each substation in Fort Erie. Readings outside of normal parameters could indicate potential failure of battery cells, which need to be replaced to ensure a continuous supply of direct current power.

CNPI plans to commence thermographic (infra-red) scanning at all substations in 2009 Test Year. Thermography captures the temperature of components compared to surrounding equipment and ambient temperature, and high relative temperatures can be indicative of overloaded or deteriorated components. These scans will be conducted typically on an annual basis and will be performed on most buswork, switchgear, and transformers. CNPI is also investigating other predictive technologies such as partial discharge testing on switchgear and vibro-acoustic testing on power transformers.

Based on the results of the predictive maintenance practices described above, CNPI forms an assessment of the condition of its assets on both a microscopic and a macroscopic perspective. On a microscopic level, deficiencies on specific components are addressed in the immediate or medium-term depending on priority. On a macroscopic level, the predictive maintenance practices provide an overall perspective of the condition of feeders and major substation components, which can then feed into the project planning process. Plans are prepared for major system upgrades and replacements to replace deteriorating and/or aging plant, and specific projects are prioritized accordingly.

(b) CNPI has not conducted formal Asset Condition Assessment studies. To date, CNPI experience has been that the predictive maintenance activities described in the response to part (a) above provide an effective means of identifying system deficiencies and assessing asset condition.

(c) CNPI's latest five-year forecast is attached to this response as Attachment A. Major capital items for the period 2010-2013 are described below. For the purposes of defining major specific projects, the 1% materiality threshold for 2009 is to establish the following thresholds: of $300,000 in Fort Erie, $120,000 in Port Colborne, and $82,000 in Gananoque.

<u>Fort Erie</u>

- Station Projects - expenditures forecast for 2011 and 2012 are for the construction of a new 8.3Y/4.8 kV Distribution Substation to serve converted 4.8 kV delta load and provide backup for Station 19.
- Line Replacements and Customer extensions – this line includes Voltage Conversion, Distribution Upgrades, and New Service Lines. Specific projects are developed in the year prior to the year in which expenditures are made. Each year, approximately $500,000 is invested in the Voltage Conversion program.

<u>Port Colborne</u>

- Station projects - expenditures forecast for 2010 through 2013 are primarily for upgrades to aging switching and protection equipment at Killally, Jefferson, and Barrick DS's.
- Line Replacements and Customer extensions – this line includes Distribution Upgrades and New Service Lines. Specific projects are developed in the year prior to the year in which expenditures are made.

Gananoque

- Station projects - expenditures forecast for 2011 through 2013 are primarily for upgrades to aging switching and protection equipment at Substation #1, Substation #2, and Leaky Creek DS.
- Transmission Lines – this line includes projects to upgrade, rebuild, and extend the 26.4 kV subtransmission system in Gananoque. Specific projects are developed in the year prior to the one in which expenditures are made.
- Line Replacements and Customer extensions – this line includes 4.16 kV Distribution Upgrades and New Service Lines. Specific projects are developed in the year prior to the year in which expenditures are made.

ATTACHMENT A – INTERROGATORY # 3

ATTACHMENT A

CNPI
DISTRIBUTION BUSINESS UNITS
FIVE-YEAR GROSS CAPITAL BUDGET
($'000)

	2007 Actual	2008 Forecast	2009 Budget	2010 Forecast	2011 Forecast	2012 Forecast	2013 Forecast
Canadian Niagara Power Inc.							
Distribution - Fort Erie							
Building Improvements-leasehold	-	-	165	-	-	-	-
Station Projects	51	210	296	290	750	1,020	370
Line Replacements and Customer Extensions	2,199	2,214	1,744	1,775	1,185	1,035	1,760
Communications and SCADA	162	28	64	190	140	85	80
Land Info. Mgmt System and Easements	3	10	10	15	20	15	20
Rebuilds, Pole Replacement and New XFMR's	278	230	245	215	235	250	205
Engineering Projects	52	43	64	30	60	25	50
Engineering Analysis Tools	8	80	100	120	50	-	-
Distribution Standards	17	4	-	5	15	5	12
New Meters	135	120	108	120	120	110	105
Tools & Equipment Distribution	50	30	30	20	70	20	35
Transportation Equipment for Inc.	261	310	320	325	325	345	310
Distribution Rebuilds Storms	56	50	64	60	50	50	60
Smart Metering	-	-	-	-	3,630	-	-
General Capital Charges	642	459	464	600	600	600	600
Total Fort Erie Distribution	**3,914**	**3,788**	**3,674**	**3,765**	**7,250**	**3,560**	**3,607**
Information Technology							
Hardware	165	307	340	180	370	220	220
Applications	43	75	99	65	55	55	55
Projects	190	200	136	130	575	1,325	275
Total Information Technology	**398**	**582**	**575**	**375**	**1,000**	**1,600**	**550**
Port Colborne							
Station Projects	50	149	1,436	230	230	275	215
Line Replacements and Customer Extensions	691	636	649	620	615	590	570
Communications and SCADA	11	8	36	130	55	35	135
Easements	2	5	5	5	10	10	12
Purchase New Dist Transformers & Regulators	66	121	131	80	75	75	70
New Meters	50	103	92	90	95	105	90
General Capital Charges	350	272	275	300	310	300	300
Smart Metering	-	-	-	-	2,092	-	-
Total Port Colborne Distribution	**1,220**	**1,294**	**2,624**	**1,455**	**3,482**	**1,390**	**1,392**
Gananoque							
Building Improvements	136	5	30	20	20	20	21
Substations	361	70	73	45	90	90	93
Transmission Lines	59	270	257	170	160	160	165
Line Replacements and Customer Extensions	229	187	259	200	210	220	227
Easements	1	-	2	-	-	-	-
Transformer	80	47	83	39	40	42	43
New Meters	19	49	11	30	32	32	33
New Tools & Equipment	11	6	7	15	20	20	21
New Transportation Equipment	204	210	-	40	-	-	-
General Capital Charges	235	170	196	238	243	243	250
Smart Metering	-	-	-	135	811	-	-
Total Gananoque Distribution	**1,335**	**1,014**	**918**	**932**	**1,626**	**827**	**852**
Total Canadian Niagara Power	**6,867**	**6,678**	**7,791**	**6,527**	**13,358**	**7,377**	**6,401**

[1] Expenditures for smart meters will incur in 2009-2011 but will be recognized as a capital expenditure in 2011 after OEB approval. During the interim period the forecast smart meter expenditures will be recognized as regulatory assets.

INTERROGATORY # 4 - Asset Management Plan

Interrogatories common to all three applications

Ref: Exhibit 2/Tab 1/Schedule 1/Appendix D – Asset Management
Ref: Exhibit 4/Tab 1/Schedule 1

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, CNPI should use its identified materiality threshold items.

a) In regards to CNPI's 2009 maintenance plans:
   i) Please provide a list of criteria and rationale that CNPI has utilized in prioritization and selection of its 2009 maintenance projects.
   ii) Please complete the following Table 1 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 CNPI's management using the criteria identified in part "a(i)", e.g. reliability statistics, customer complaints, cost information, etc.

Table 1 – 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						
2	e.g. Tree trimming	Ongoing	Preventive	This project is to perform tree trimming based on a three-year cycle	$	To enhance system reliability and maintaining SAIDI <X, SAIFI < Y, and CAID < Z and reduce outages to the customers
3						
4						
….						
….						
Total Prioritized Programs					$$	
Total Prioritized Programs % of Overall 2009 Maintenance Programs					%	

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.

b) In regards to CNPI's 2009 capital plans:

i) Please provide a list of criteria and rationale that CNPI has utilized in prioritization and selection of its 2009 capital projects.

ii) Please complete the following Table 2 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 CNPI's management using the criteria identified in part "b(i)", e.g. asset condition study, system planning, regulatory compliance, etc.

Table 2 – 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								
2								
3	e.g. New 27.6 kV	This project is to build a new U/G feeder from Station ABC	Addition of a new asset	$	Non-discretionary	June 09	Dec. 09	To relief the overloading of the existing underground feeders and meet the load growth of x% forecasted in the next y years.
4								
….								
….								
Total $ for Prioritized Programs				$$$				
Total $ Prioritized Programs as a % of Overall Total 2009 CAPEX				%				
Discretionary Programs as % of Total Prioritized Programs				%				
Non-discretionary Programs as % of Total Prioritized				%				

Programs			
Replacement Programs as % of Total Prioritized Programs		%	
Rehabilitation Programs as % of Total Prioritized Programs		%	
Upgrade Programs as % of Total Prioritized Programs		%	
New Additions as % of Total Prioritized Programs		%	

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.

RESPONSE:

(a) Maintenance Plans:

i) CNPI maintenance programs are designed to optimize the value of capital investments and maintain equipment in proper working condition. This reduces the risk of equipment failure, enhances safety, and improves reliability of supply to customers. In selecting maintenance programs, CNPI considers these three main criteria:

- Equipment Lifespan: Effectively maintaining equipment in good condition to maximize equipment lifespan.

- Safety: Maintenance programs are selected that would remove any major threats to CNPI personnel or public safety and proactively reduce any longer-term hazards.
- Reliability: Maintenance programs are selected to remove imminent threats to reliability and enhance longer-term reliability performance.

The rationale for some projects can be based on a combination of the above criteria.

ii) Table 1 is attached to this response as Attachment A.

iii) CNPI does not have documented evidence for how the priorities of these projects are determined. The only single maintenance program that meets the materiality threshold is the vegetation management programs. These programs are essential to maintaining appropriate clearances between lines and vegetation to reduce the possibility of tree contacts, thereby enhancing safety and reliability.

(b) Capital Plans.

i) CNPI utilized four main criteria in selecting its 2009 capital projects:

- Asset condition: Sustaining assets in good long-term working condition is essential to maintaining safe, reliable, and economical distribution systems. Replacing aged and/or deteriorating plant enhances system safety and reliability. In evaluating asset condition, where applicable CNPI also considers factors such as ease of maintenance and reliability performance.
- System planning: To ensure that sufficient system capacity, both from a load and voltage perspective, is available to serve existing customers and meet the demands of future customers.
- Contingency planning to meet two goals:

1) ensure that adequate system capacity exists to serve customers from alternate sources in emergencies such as when a major component fails, and
2) reduce the number of customers affected by forced line outages.

- Cost: CNPI considers cost factors to ensure that capital expenditures are reasonable and appropriate by providing optimal benefit to the system.

The rationale for some projects can be based on a combination of the above criteria.

ii) Table 1 is attached to this response as Attachment B.

iii) Capital project priority is determined during consultation between Engineering and Operational staff. During the budgeting process, justifications are submitted for each project for management review. Once approved, the project is included in the budget.

ATTACHMENT A – INTERROGATORY # 4

Table 1 - 2009 Maintenance Programs (Fort Erie)

Materiality threshold: $65,294

Priority Ranking	Program Name	Ongoing or One-Time	Type of Program	Description of Program	Maintenance Expenditure ($)	Rationale for Priority Selection
1	Vegetation Management	Ongoing	Preventive	Perform vegetation management on 3-year cycle	244,055	Essential to maintain proper clearances between vegetation and equipment. Avoiding tree contacts reduces customer interruptions and enhances system reliability and safety.
Total Prioritized Programs					244,055	
Total $ Prioritized Programs as a %of Overall 2009 Maintenance Programs					13%	

Table 1 - 2009 Maintenance Programs (Port Colborne)

Materiality threshold: $48,004

Priority Ranking	Program Name	Ongoing or One-Time	Type of Program	Description of Program	Maintenance Expenditure ($)	Rationale for Priority Selection
1	Vegetation Management	Ongoing	Preventive	Perform vegetation management on 3-year cycle	128,046	Essential to maintain proper clearances between vegetation and equipment. Avoiding tree contacts reduces customer interruptions and enhances system reliability and safety.
Total Prioritized Programs					128,046	
Total $ Prioritized Programs as a %of Overall 2009 Maintenance Programs					13%	

Table 1 - 2009 Maintenance Programs (EOP)

Materiality threshold: $16,651

Priority Ranking	Program Name	Ongoing or One-Time	Type of Program	Description of Program	Maintenance Expenditure ($)	Rationale for Priority Selection
1	Vegetation Management	Ongoing	Preventive	Perform vegetation management on 3-year cycle	86,343	Essential to maintain proper clearances between vegetation and equipment. Avoiding tree contacts reduces customer interruptions and enhances system reliability and safety.
Total Prioritized Programs					86,343	
Total $ Prioritized Programs as a %of Overall 2009 Maintenance Programs					17%	

ATTACHMENT B – INTERROGATORY # 4

Table 2 - 2009 Capital Project (Fort Erie)

Materiality threshold: $300,000 (lower threshold of $200,000 applied)

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	Gorham/Stevensville Rd Rebuild	New 34.5 kV line to replace old 17L67 line	Replacement	$ 200,000	Non-Discretionary	Feb. 2009	May 2009	Asset condition. Replace aging section of 34.5 kV feeder and relocate inaccessible sections to road allowance.
1	Station 12 Feeder Rebuild	Replacing old aerial cables with overhead lines	Replacement	$ 200,000	Non-Discretionary	Apr. 2009	Sept. 2009	Asset condition. Project will replace deteriorating sections of 4.8 kV feeders to extend life and improve system security.
2	Dominion Rd Conversion, part 1	Voltage conversion of Ratio Bank 67RT4	Rehabilitation	$ 250,000	Discretionary	May 2009	Oct. 2009	System planning. Convert 4.8 kV delta lines to 8.3 kV wye.
2	Station 12 underground cable replacement	Replacing feeder underground sections and riser poles	Replacement	$ 230,000	Discretionary	June 2009	Nov. 2009	Asset condition. Project will replace aging components and extend feeder life
Total $ for Prioritized Programs				$ 880,000				
Total $ Prioritized Programs as a %of Overall Total 2009 CAPEX				21%				
Discretionary Programs as % of Total Prioritized Programs				55%				
Non - Discretionary Programs as % of Total Prioritized Programs				45%				
Replacement Programs as % of Total Prioritized Programs				72%				
Rehabilitation Programs as % of Total Prioritized Programs				28%				
Upgrade Programs as % of Total Prioritized Programs								
New Additions as % of Total Prioritized Programs								

Table 2 - 2009 Capital Project (Port Colborne)

Materiality Threshold: $120,000

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	Beach Road Substation	Construct new Beach Road Substation	New addition	$ 1,616,383	Non-Discretionary	Sept. 2008	June 2009	System planning and asset condition. New substation will meet the load growth in the area, replace aging Wilhelm substation, and improve system security
2	Killally Station feeder upgrades	Upgrade capacity of Killally Station feeders	Upgrade	$ 200,000	Discretionary	May 2009	Dec. 2009	Contingency planning and asset condition. Project will increase feeder transfer capability and improve system security
Total $ for Prioritized Programs				$ 1,816,383				
Total $ Prioritized Programs as a %of Overall Total 2009 CAPEX				68%				
Discretionary Programs as % of Total Prioritized Programs				11%				
Non - Discretionary Programs as % of Total Prioritized Programs				89%				
Replacement Programs as % of Total Prioritized Programs								
Rehabilitation Programs as % of Total Prioritized Programs								
Upgrade Programs as % of Total Prioritized Programs				11%				
New Additions as % of Total Prioritized Programs				89%				

Table 2 - 2009 Capital Project (EOP)

Identified materiality threshold: $82,170

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	Subtransmission line pole replacement	Replacing deteriorated poles on the 26.4 kV system	Replacement	$ 150,000	Non - Discretionary	Jan. 2009	Dec. 2009	Asset condition. Project will replace deteriorating plant and improve system safety and reliability
1	Distribution system pole replacement	Replacing deteriorated poles on the 4.16 kV system	Replacement	$ 125,000	Non - Discretionary	Jan. 2009	Dec. 2009	Asset condition. Project will replace deteriorating plant and improve system safety and reliability
2	East Side Town Loop upgrade	Upgrade the feeder to 336 ASC conductor	Upgrade	$ 100,000	Discretionary	Apr. 2009	Oct. 2009	Contingency planning. Project will increase line capacity and system reliability
2	4.16 kV feeder upgrade	Upgrade 4.16 kV feeder capacity and build feeder interties	Upgrade	$ 120,000	Discretionary	May 2009	Dec. 2009	Contingency planning. Project will increase line capacity and system reliability
Total $ for Prioritized Programs				$ 495,000				
Total $ Prioritized Programs as a %of Overall Total 2009 CAPEX				57%				
Discretionary Programs as % of Total Prioritized Programs				44%				
Non - Discretionary Programs as % of Total Prioritized Programs				56%				
Replacement Programs as % of Total Prioritized Programs				56%				
Rehabilitation Programs as % of Total Prioritized Programs								
Upgrade Programs as % of Total Prioritized Programs				44%				
New Additions as % of Total Prioritized Programs								

INTERROGATORY # 5 – Depreciation Expense

Interrogatories common to all three applications

Ref: Exhibit 2/Tab 2/Schedule 4 and Exhibit 2/Tab 2/Schedule 5 – Depreciation Expense

Board staff has prepared the following table of documented Depreciation Rates from Appendix B of the 2006 Electricity Distribution Rate Handbook, from Appendix 4: Amortization Rates of CNPI's 2006 EDR application for each of the three service territories, and from Exhibit 4 / Tab / Schedule 7 of CNPI's 2009 Cost of Service application for each service territory.

a) Please confirm or revise the rates documented in the table;
b) It appears that, in 2006 EDR applications, CNPI was using depreciation rates that differed in some asset categories between the three service territories. However, CNPI appears to be using a common set of depreciation rates, which differ in some cases from the Board's standard depreciation rates. Please explain any impact of CNPI going to a common set of depreciation rates;
c) Please explain CNPI's reasons for transitioning to depreciation rates that differ from those documented by the Board in the 2006 EDRH and the Accounting Procedures Handbook.
d) It appears that CNPI did not have a stated depreciation rate for account 1980 – GA System Supervisory Equipment in its 2006 EDR applications. Please explain CNPI's reasons for adopting a depreciation rate of 10% (10 year expected life) as opposed to the 6.67% rate (15 year expected life) documented in the 2006 EDRH and Accounting Procedures Handbook

Depreciation/Amortization Rates

		Board (2006 EDRH) Effective January 1, 1992		CNPI (2006 EDR)			CNPI (2009 EDR)		
Account	**Description**	**Life-years**	**Rate (%)**	**Fort Erie EB-2005-0343**	**Port Colborne EB-2005-0344**	**Eastern Ontario Power (Gananoque) EB-2005-0345**	**Fort Erie EB-2008-0223**	**Port Colborne EB-2008-0224**	**Eastern Ontario Power (Gananoque) EB-2008-0222**
1608	Franchises & Consents						2.50%	2.50%	2.50%
1805	D Land	non-depreciable		non-depreciable	non-depreciable	non-depreciable	non-depreciable	non-depreciable	non-depreciable
1806	D Land Rights						2.50%	2.50%	2.50%
1808	D Bldgs & Fixtures	50 and 25	2% and 4%	2% and 3%	2% and 3%	2%	2%	2%	2%
1820	D Stn Equipment < 50 kV	30	3.33%	3%	3.33%	***2% and 3%***	3%	3%	3%
1830	D Poles, Towers & Fixtures	25	4%	3% and 4%	3% and 4%	3% and 4%	4%	4%	4%
1835	D OH Cond & Devices	25	4%	3% and 4%	3% and 4%	3% and 4%	3%	3%	3%
1840	D UG Cond & Manholes	25	4%	2% and 3%	2%, 3% and 4%	2% and 3%	2%	2%	2%
1845	D UG Cond & Devices	25	4%	2% and 3%	2%, 3% and 4%	2% and 3%	3%	3%	3%
1850	D Line Transformers	25	4%	3% and 4%	3% and 4%	3% and 4%	3%	3%	3%
1855	D Services	25	4%	2%, 3% and 4%	2%, 3% and 4%	2%, 3% and 4%	3%	3%	3%
1860	D Meters	25	4%	3% and 4%	4%	3% and 4%	3%	3%	3%
1865	D Other Install on Cust Prem								
1875	D St Lites & Signal Systems								
1908	GA Bldgs & Fixtures	50	2%	2% and 3%	2% and 3%	2%	2%	2%	2%
1910	Leasehold Improvements	Over term of lease					20%		
1915	GA Off Furn & Equipment	10	10%	10% and 20%	10%	10%	10%	10%	10%

1920	GA Comp Hardware	5	20%	10 and 20%	20%	10% and 20%	20%	20%	20%
1925	GA Comp Software						10%	10%	10%
1930	GA Transportation Equipment	4,5,8	25%, 20%, 12.5%	10%	***12.5%*** and 20%	10%	10%	10%	10%
1935	GA Stores Equip	10	10%	10%	10%	#N/A	10%	10%	10%
1940	GA tools, shop & garage equip	10	10%	10%	10% and 20%	***10%***	10%	10%	10%
1945	GA measure & test equip						10%	10%	10%
1950	GA power op equip	8	12.50%	5% and 10%	#N/A	#N/A	10%	10%	10%
1955	GA Comm Equipment						5%	5%	5%
1960	GA Misc Equip						20%	20%	20%
1965	Water heater rental units	10	10%	#N/A	#N/A	#N/A			
1970	Load management control - customer premises	10	10%	#N/A	#N/A	#N/A			
1975	Load management control - utility premises	10	10%	#N/A	#N/A	#N/A			
1980	GA System Supv Equip	15	6.67%	#N/A	#N/A	#N/A	10%	10%	10%
1985	Sentinel Lighting rental units	10	10.00%	#N/A	#N/A	#N/A			
1995	Contributed Capital								

RESPONSE:

a) Please see some revisions made in the above table which are in bold-italics.

b) CNPI used common depreciation rates in the 2006 EDR in all three service territories. Where in Appendix 4: Amortization Rates, in the 2006 EDR, there appear to be inconsistencies, in fact the depreciation rates within the capital accounting SAP module are consistent. This schedule was a high level summary of a more detailed amortization rates schedule and as such included some judgment as to what rates to include.

c) CNPI was not previously subject to the former Ontario Hydro manual for Municipal Utilities in Ontario. As per the Accounting Procedures Handbook Article 410, and consistent with the 2006 EDR (and as confirmed by Mr. Keith Ritchie of the Ontario Energy Board in 2005) CNPI has been grandfathered to use its historical rates as set out in these applications. CNPI is presently studying the implications of conversion to the International Financial Reporting Standards ["IFRS"]. One of the likely outcomes is that CNPI will have a full depreciation study performed on its assets. At that time all depreciation rates will be reviewed. CNPI is also awaiting further guidance from the Ontario Energy Board on capital accounting under IFRS before undergoing any project. The timing of this project is at this time unknown.

d) Since the 2006, EDR CNPI has continued to improve its financial reporting with respect to capital accounting. As a result, some asset categories that were grouped together in the 2006 EDR have subsequently been split out into separate categories. The GA System Supervisory Equipment, which is mainly SCADA computerized software, was grouped in with GA Computer Software in the 2006 EDR. The depreciation rate in the 2006 EDR for such assets was 10%. This is consistent with the 2009 EDR.

INTERROGATORY # 6 - Overhead Distribution Lines

CNPI – EOP specific interrogatories

Ref: Exhibit 2/Tab 3/Schedule 1/Appendix A/page 9 – Overhead Distribution Lines

Under the 2009 Test Year, please identify the estimated project cost for the replacement of 25 poles in various locations of the 4.16 kV distribution system.

RESPONSE:

The estimated project cost is $125,000 based on twenty-five poles at $5,000 per pole.

This cost includes labour, material and transportation.

INTERROGATORY # 7 - Meters

CNPI – EOP specific interrogatories

Ref: Exhibit 2/Tab 1/Schedule 1 and Exhibit 2/Tab 3/Schedule 1/Appendix A/ page 11 – Meters

CNPI provides the following table for meter capital expenditures:

Year	2006 Actual	2007 Actual	2008 Bridge	2009 Test
Exhibit 2 / Tab 1 / Schedule 1	$59,786	$25,684	$58,878	$36,880
Exhibit 2 / Tab 3 / Schedule 1 / Appendix A Investment ($)	$24,000	$23,000	$58,000	$14,000

CNPI states: "Increased capital expenditure levels for 2008 Bridge Year reflect an increased emphasis on meter changeouts to meet reverification requirements." It then states: "CNPI has deferred meter changeouts until a decision is made regarding the smart meter technology that will be employed in the smart meter implementation planned for 2009. Once CNPI selects a technology and vendor, the smart meter specifications will be used for future meter changeouts. This will avoid the incremental cost of installing conventional meters in 2008, then replacing them in 2009 with smart meters."

a) Please explain the differences between the two exhibits as shown in the above table.

b) Please provide further explanation of meter capital expenditures by year, breaking out actual and forecast expenditures by:
   i) Wholesale meters
   ii) Residential meters
   iii) General Service < 50 kW non-interval meters
   iv) General Service, Intermediate and Large Use Interval meters.

c) What, if any, options has CNPI considered, to avoid capital expenditures for conventional meter expenditures until CNPI is authorized to and commences smart meter deployment.

d) Is CNPI making efforts to become authorized to deploy smart meters pursuant to O. Reg. 427/06 as amended on June 25, 2008? If yes, please provide further explanation.

e) Please provide CNPI's estimate of when it expects to begin smart meter deployment once authorized.

RESPONSE:

a) The differences between the two exhibits are a result of the difference between capital project orders used for managing the capital expenditures and the OEB asset classes.

The amounts shown in Exhibit 2/Tab 3/Schedule 1/Appendix A are the capital expenditures that the business has made through project orders. The project orders normally contain a number of different asset classes and include all expenditures made in the year but capitalized in the following year.

The amounts shown in Exhibit 2/Tab 1/Schedule 1 are the actual amounts capitalized in that particular year. These amounts consist of all or portions of numerous project orders and may also include intercompany transfers.

b) The requested information is provided in the table below.

	2006 Actual	**2007 Actual**	**2008 Bridge Year**	**2009 Test Year**
Wholesale	$0	$0	$0	$0
Residential	15,700	18,400	5,000	1,000
Gen. Service < 50 kW	6,200	2,900	6,500	2,000
Gen. Service, Intermediate, Large Use	2,100	1,700	2,500	2,000
TOTAL	**$24,000**	**$23,000**	**$14,000**	**$5,000**

Amounts for 2008 Bridge Year and 2009 Test Year have been adjusted from budgeted amounts. CNPI-EOP will be deploying Smart Meters and Automated Meter Infrastructure (AMI) in 2009, and is, therefore, reducing purchases of conventional residential meters in anticipation of the mass Smart Meter deployment.

c) In anticipation of Smart Meter/AMI deployment in 2009, to avoid capital expenditures for new meters CNPI-EOP deliberately scaled back on the purchase of conventional meters in 2008 and will do the same in 2009. CNPI-EOP also scaled back on 2008 meter changeouts for Measurement Canada reverification requirements and used available reverified meters as much as possible to avoid purchasing new meters. Measurement Canada was informed of CNPI–EOP plans in this regard. Reforecasted meter capital expenditures for 2008 and 2009 are shown in the table in response (b) above.

d) CNPI-EOP is part of the Niagara Erie Power Association (NEPA). NEPA is a consortium comprising nine utilities in the Niagara Region that is pursuing a collective approach to Smart Meter/AMI implementation. NEPA engaged the services of Util-Assist, Inc. to facilitate the process; a service that Util-Assist is also providing to other utility consortiums in Ontario working towards Smart Meter/AMI implementation. NEPA has prepared technical and economic models for evaluating Smart Meter/AMI suppliers and installers and temporary Operational Data Storage (ODS) providers. Pursuant to O. Reg. 427/06, NEPA "piggybacked" on the London Hydro RFP process for selecting a Smart Meter/AMI supplier. The evaluation process was facilitated by London Hydro and overseen by a Fairness Commissioner authorized by the Ministry of Energy. As a result of this process, Sensus Technologies was selected as the Smart Meter/AMI supplier for the NEPA consortium. Progress to date on Smart Meter/AMI implementation can be summarized as follows:

- Sensus selected as Smart Meter/AMI supplier. Contract expected to be signed by December 31, 2008.
- Proposals for Installation services are currently being evaluated and a decision will be made following such evaluation.
- RFP issued for temporary ODS services.

e) By “piggybacking” on the London Hydro RFP process in accordance with the provisions of O. Reg. 427/06, the NEPA consortium and CNPI-EOP is authorized by the Ministry of Energy to deploy Smart Meter/AMI infrastructure. CNPI-EOP expects to commence deployment in July 2009.

INTERROGATORY # 8 - Underground Assets

CNPI – EOP specific interrogatories

Ref: Exhibit 2/Tab 1/Schedule 1 and Exhibit 2/Tab 3/Schedule 1 – Underground Assets

CNPI provides the following information on capital expenditures related to underground distribution assets in each of the exhibits:

		2006 Actual	2007 Actual	2008 Bridge	2009 Test
Exhibit 2 / Tab / Schedule 1					
1840	D UG Cond & Manholes	$ 2,114	$ 1,478	$ 969	$ 3,232
1845	D UG Cond & Devices	$ 3,909	$ 26,738	$ 14,535	$ 48,485
Exhibit 2 / Tab 3 / Schedule 1 / Appendix A					
	Underground Distribution Lines	$ 26,000	$ 47,000	$ 19,000	$ 65,000

Please explain the differences between the numbers shown in the two exhibits.

RESPONSE:

Please see response to Question OEB-07 Part A.

INTERROGATORY # 9 – Service Quality & Reliability

<u>CNPI – EOP specific interrogatories</u>

Ref: Exhibit 1/Tab 2/Schedule 1 and Exhibit 2/Tab 1/Schedule 1/Appendix B – Service Reliability

On page 8 of this Exhibit, CNPI states that "[it] has made a significant capital investment in its distribution system [i.e. serving Gananoque]. This has benefited ratepayers by maintaining a high level of reliability. SAIDI and SAIFI indices for CNPI – EOP have increased over a three-year period."

a) Increasing values for SAIDI and SAIFI would be indicative of decreasing reliability. Please clarify what is meant by the statement that "SAIDI and SAIFI indices in Gananoque have increased … ."

b) Please provide reliability performance data for the CNPI – EOP service area in the following table format.

	All Causes of Interruptions			All Interruptions except for Loss of Supply (Cause Code 2)		
Year	SAIDI	SAIFI	CAIDI	SAIDI	SAIFI	CAIDI
2002						
2003						
2004						
2005						
2006						
2007						

c) Please indicate any reliability indicator and year where performance was out of standard, meaning that it was higher than the range of the previous years. For any such case, please provide an explanation for the decreased reliability and the actions taken by CNPI to address the issue.

d) Please provide the derivation of the three-year averages shown in the table in Exhibit 2/Tab 1/Schedule 1/Appendix B/page 2/line 4.

RESPONSE:

(a) Increasing values for SAIDI and SAIFI are indicative of decreasing reliability. In the Application, pages 8-9 of Exhibit 1, Tab 2, Schedule 1 and page 2 of Exhibit 2, Tab 1, Schedule 1, Appendix B concurred with this statement by explaining that the increasing indices in Gananoque reflect a transitory decline in reliability performance. This decline was described as transitory since over the past few years there were several interruptions that affected large numbers of customers. In certain cases the entire Town of Gananoque was affected. In addition, planned interruptions have been necessary to perform line rebuilds and facilitate construction of the new Main Substation. Interruptions affecting significant portions of the customer base have had an adverse impact on reliability performance in Gananoque. In the future, it is expected that system improvements being undertaken by CNPI-EOP will result in improved reliability performance on the distribution system.

(b)

	All Causes of Interruptions			All Interruptions except for Loss of Supply (Cause Code 2)		
Year	SAIDI	SAIFI	CAIDI	SAIDI	SAIFI	CAIDI
2002	N/A	N/A	N/A	N/A	N/A	N/A
2003	9.22	3.06	3.01	3.16	1.10	2.87
2004	1.60	1.54	1.04	1.60	1.54	1.04
2005	4.07	1.05	3.89	**4.07**	1.05	**3.89**
2006	10.93	3.47	3.16	**7.43**	**2.47**	3.01
2007	10.13	5.78	1.75	5.18	**3.82**	1.36

(c) Data for 2002 is unavailable, as CNPI-EOP purchased the utility in 2003. Any indices that are higher than the range of previous years' performance are highlighted in bold in the "All Interruptions except for Loss of Supply" section of the Table, as CNPI-EOP has no control over Loss of Supply events. Explanations for the out-of-range performances are as follows:

- In 2005 compared to 2004, SAIDI increased to 4.07 and CAIDI increased to 3.89, while SAIFI decreased to 1.05. These numbers indicate that in 2005 there were a few interruptions that affected significant numbers of customers and were of lengthy duration. There were four major planned interruptions during the year to carry out 4.16 kV line upgrades and build feeder interties. These four interruptions accounted for approximately 66% of the total SAIDI for 2005. These interruptions were unavoidable because of the lack of existing feeder interties to provide alternate sources to supply customers. As CNPI-EOP continues to construct feeder interties, the risk of such widespread, lengthy interruptions in the future will be reduced because smaller sections of line can be isolated while significant numbers of customers can be supplied from alternate sources.

- In 2006, SAIDI increased to 7.43 while SAIFI increased to 2.47 and CAIDI decreased to 3.01. The numbers indicate that, on average, interruptions in 2006 were lengthy and affected larger numbers of customers than in 2005. Apart from one Loss of Supply event, there was one distribution system interruption that affected the entire territory. This was a planned interruption to the existing Thermal Plant Substation to facilitate construction of a 44 kV line extension to serve the future Main Substation. This interruption contributed to 56% of the total SAIDI for 2006, and was unavoidable because Gananoque has only a single 44 kV supply. The new Main Substation was designed to minimize the risk of outages to the entire substation, though the risk cannot be entirely mitigated because of the sole-source supply to the Town. In addition, an interruption to the Gananoque Substation during a rainstorm contributed 22% of the 2006 SAIDI.
- In 2007, SAIFI increased to 3.82 though SAIDI and CAIDI decreased from 2006 values. This indicates that in 2007, there were more interruptions that affected large numbers of customers than occurred in 2006. However, interruptions on average were of shorter duration than in 2006. Apart from one Loss of Supply event, in 2007 there were three interruptions that affected the entire distribution system and were the major cause of the increased SAIFI index. One was a planned interruption to facilitate commissioning of the new Main Substation and one due to an ice storm. In the third incident, the main breaker at the (then in-service) Thermal Plant Substation tripped on backfeed during a period of low-load when the embedded hydro generation exceeded the system load, resulting in power flowing into the Hydro One grid. Because metering facilities at the time were not configured to measure feeds into the Hydro One system, the main breaker was set to trip on backfeed.

Together, these three interruptions contributed 80% of the SAIFI for 2007. The planned interruption to commission the new Main Substation was unavoidable while the ice storm was a severe act of nature. The backfeed issue has been corrected with the installation of metering facilities that measure power flow into the Hydro One grid.

(d) The 2007 data displayed in the Application were incorrect and the three-year averages incorrectly computed. The correct data is as shown in the "All Interruptions Except for Loss of Supply (Cause Code 2)" section of the table in Response (b) above. The correct 3-year averages are as follows:

SAIDI: 5.56
SAIFI: 2.45
CAIDI: 2.75
ASAI: 99.937

INTERROGATORY # 10 - Smart Meters

CNPI – EOP specific interrogatories

Ref: Exhibit 1/Tab 2/Schedule 1/page 14 and Exhibit 9/Tab 1/Schedule 1/ page 11 – Smart Meters

In Exhibit 1/Tab 2/Schedule 1, at page 14, CNPI states "CNPI – Gananoque is not authorized to conduct discretionary smart metering activities and as such is not requesting a change to the current Board Approved Smart Metering Rate Adder of $0.27 per metered customer."

In Exhibit 9/Tab 1/Schedule 1, at page 11, CNPI states "CNPI – Eastern Ontario Power is not authorized to conduct discretionary smart metering activities and as such is not requesting a change to the current Board Approved Smart Metering Rate Adder of $0.26 per metered customer.

a) Please confirm the smart meter funding adder approved by the Board and embedded in CNPI – EOP's current Board-approved distribution rates.
b) Please confirm the smart meter funding adder that CNPI is seeking approval for, for the 2009 test year, in this Application.
c) Please confirm the smart meter funding adder that CNPI is seeking approval for, for the 2009 test year, in this Application.

RESPONSE:

a) The smart meter funding adder approved by the Board and embedded in CNPI – Eastern Ontario Power's current Board-approved distribution rates is $0.26.

b) The smart meter funding adder that CNPI is seeking approval for, in respect of 2009 Test Year, in the Application is $0.27.

   To qualify this, should the Board approve harmonization of distribution rates for Fort Erie and Gananoque the smart meter adder requested for Gananoque is $0.27. However, should the Board elect to maintain separate rate structures, the smart meter adder requested for Gananoque remains at the current Board approved amount of $0.26.

The rationale for the change from $0.26 to $0.27 in the harmonized rate proposal is based on the Board's initial determination in the 2006 EDR. The Board determined the smart meter rate adder by assigning a value of $0.30 per residential customer and then prorating that amount over all metered customers.

In Fort Erie there were 13,717 residential customers; at $0.30 per customer this yielded $4,115.10 in monthly funding. In total there were 15,000 metered customers; dividing the 15,000 customers by the funding of $4,115.10 resulted in a smart meter adder of $0.27.

In Gananoque there were 3,072 residential customers; at $0.30 per customer this yielded $921.60 in monthly funding. In total there were 3,504 metered customers; dividing the 3,504 customers by the funding of $921.6 resulted in a smart meter adder of $0.26.

If the quantities for Fort Erie and Gananoque are added together there are 16,789 residential customers; at $0.30 per customer this yielded $5,036.70 in monthly funding. In total there are 18,504 metered customers; dividing the 18,504 customers by the funding of $5,036.70 results in a smart meter adder of $0.27. In essence, the level of funding for the combined customer count does not change from the aggregate amount already approved by the Board in the 2006 EDR; however, the customer mix is such that in order to collect the funding from all metered customers the smart meter adder is $0.27 for both Fort Erie and Gananoque customers.

INTERROGARY # 11 - Computer Hardware and Software

CNPI – Fort Erie specific interrogatories

Ref: Exhibit 2/Tab 1/Schedule 1, Exhibit 2/Tab 1/Schedule 1/Appendix C and Exhibit 2/Tab 3/Schedule 1/Appendix B – Computer Hardware and Software

On page 2 of Exhibit 2/Tab 1/Schedule 1, CNPI provides a table showing capital expenditures by year and by asset account. For Computer Hardware and Software, the following data are provided:

Account		2006 Actual	2007 Actual	2008 Bridge	2009 Test	Cumulative Total
1920	GA Comp Hardware	$ 160,293	$ 184,501	$ 145,864	$ 345,701	$ 836,359
1925	GA Comp Software	$ 200,886	$ 233,718	$ 208,324	$ 238,792	$ 881,720
	Total Computer Hardware/Software capex	***$ 361,179***	***$ 418,219***	***$ 354,188***	***$ 584,493***	***$ 1,718,079***
Total Capital Expenditures (before CIAC)		$ 3,949,523	$ 4,312,787	$ 4,327,533	$ 4,116,771	$ 16,706,614
	Computer capex as % of total capex	9.14%	9.70%	8.18%	14.20%	10.28%

In Appendix C of the Exhibit, CNPI documents its IT strategy. CNPI documents that SAP is a core part of its Information Technology strategy. After a review in 2007, a decision on upgrading SAP in 2010 was deferred, and CNPI states that it will review its decision again in 2009 regarding an upgrade in 2010/11.

In Exhibit 2/Tab 3/Schedule 1/Appendix B, CNPI documents SAP expenditures of at least $100,000 in each year from 2006 actual to 2009 test.

In light of CNPI's IT Strategy documented in Appendix C, please explain CNPI's ongoing computer hardware and software capital expenditures, which amount to $1.718 Million cumulative from 2006 to 2009 and represent an average of about 10% of annual capital expenditures.

RESPONSE:

The management of CNPI's IT assets includes capital expenditures in hardware and software. While CNPI's IT strategy involves continued use of the existing version of SAP, ongoing capital expenditures are made to replace out of warranty hardware and for improvements and automations to enhance customer service and comply with regulatory requirements.

Hardware

Workstations and laptops have a five year lifecycle after which they are replaced. Servers also have a five year lifecycle based on the warranty available by the hardware vendor and business requirements. SAP servers also follow a similar replacement schedule, notwithstanding the decision to continue with the existing version of SAP. A detailed discussion of the hardware purchased has been provided in Exhibit 2, Tab 3, Schedule 1, Appendix B, pages 1 – 4.

Software

CNPI's corporate software includes all applications associated with workstations and/or servers. Operating system, productivity and function specific software are included in this allocation. A detailed discussion of the software and IT projects is set out in Exhibit 2, Tab 3, Schedule 1, Appendix B, pages 4 – 7.

INTERROGATORY # 12 - Transportation

CNPI – Fort Erie specific interrogatories

Ref: Exhibit 2/Tab 1/Schedule 1 – Transportation

On page 2 of Exhibit 2/Tab 1/Schedule 1, CNPI provides a table showing capital expenditures by year and by asset account. For Transportation, the following data are provided:

Account		2006 Actual	2007 Actual	2008 Bridge	2009 Test	Cumulative Total
1930	GA Transportation Equipment	$ 397,207	$ 299,862	$ 354,199	$ 365,198	$ 1,416,466
Total Capital Expenditures (before CIAC)		$ 3,949,523	$ 4,312,787	$ 4,327,533	$ 4,116,771	$ 16,706,614
	Transportation capex as % of total capex	10.06%	6.95%	8.18%	8.87%	8.48%

In Exhibit 2/Tab 3/Schedule 1 Appendix A, on pages 12 and 13 under Transportation Equipment, CNPI provides further documentation on the types of vehicles being purchased in each year.

a) Please explain why CNPI documents $158,000 in vehicle capital expenditures for 2006 Actuals in the table on Exhibit 2/Tab 3/ Schedule 1/Appendix A/page 12/line 23, but $397,207 in Exhibit 2/Tab 1/Schedule 1.

b) Are these vehicles dedicated to serving CNPI's Fort Erie distribution customers only?

c) If the answer to b) is in the negative, please explain how the capital costs are allocated to other of CNPI's distribution and transmission operations, as applicable, or how cost recovery when these assets are utilized elsewhere is effected.

d) Based on the above analysis, CNPI has spent or plans to spend $1.416 Million cumulative from 2006 to 2009. This represents an average of about 8.5% of annual capital expenditures. Please provide further explanation of CNPI's transportation capital strategy in support of these expenditures.

RESPONSE:

a) The $158,000 relates to four vehicles purchased in 2006 as explained in Exhibit 2 / Tab 3 / Schedule 1 Appendix A, on pages 12 and 13. Additional expenditures of approximately $158,000 were made on new braking and winching units that were not included in the transportation explanation as they were included in a different project order [See OEB-7 (a)]. A transfer of $81,000 was recognized both as an addition and retirement in 2006.

b) No, these vehicles are not dedicated to serving CNPI-Fort Erie's distribution customers only. CNPI's vehicles in Fort Erie are generally used to serve the CNPI-Fort Erie, CNPI-Port Colborne, and CNPI-transmission business units.

c) The capital costs for ratemaking purposes are allocated to each business unit based on an allocation factor as described in the BDR report (Exhibit 4, tab 2, Schedule 4, Appendix B, page 6).

d) CNPI has a vehicle replacement cycle that is updated annually based on assessments of future operational needs and the condition of existing vehicles. CNPI has targeted time periods for vehicle replacement, though vehicles may be retained for longer periods depending on their condition. The target replacement periods for different classes of vehicle are as follows:

   a. Line trucks: 10 years.
   b. Pickup trucks: 5 years.
   c. Cargo vans: 8 years.
   d. Pool vehicles: 180,000 km.

INTERROGATORY # 13 – Station 12 Projects

CNPI – Fort Erie specific interrogatories

Ref: Exhibit 2/Tab 3/Schedule 1/Appendix A – Station 12 Projects

CNPI documents the following capital expenditures to refurbish Station 12, its largest distribution station and one which is 60 years old:

Year	2006 Actual	2007 Actual	2008 Bridge	2009 Test	Cumulative Total
Investment	$66,000	$32,000	$207,000	$230,000	$ 535,000

a) Please provide CNPI's forecasts, if available, for Station 12 capital expenditures for the period 2010-2012.

Please explain what options to its approach for sustaining the 60-year facility, such as replacement, CNPI has considered. Please explain CNPI's rationale for adopting its approach to sustain the existing distribution station

RESPONSE:

Since the filing of the Application, CNPI has deferred the Station 12 works planned for 2008 Bridge Year into 2009 Test Year in order to reallocate investments to Distribution Upgrades. As a consequence, investment planned for 2009 Test Year was deferred to 2010. Revised forecasts for 2008 Bridge Year, 2009 Test Year, and for the period 2010-2012 are shown below.

Year	2006 Actual	2007 Actual	2008 Bridge	2009 Test	2010	2011	2012	Total
	$66,000	$32,000	$12,000	$230,000	$210,000	$50,000	$25,000	$625,000

Investments for 2009 Test Year and 2010 are for the replacing underground cables, upgrading riser poles, and upgrading the ground grid. Investments planned for 2011 and 2012 are for upgrading protection systems by replacing aged electromechanical relays with modern microprocessor-based relays.

In devising its plan for sustaining this station, CNPI did consider the option of replacing the facility. Key factors in the decision process were:

1. Replacement cost. This was estimated at $2.5 million.
2. Condition of existing components. The buswork, breakers, medium-voltage switchgear, and power transformers at Station 12 are still in good operating condition.
3. Timeframe over which Station 12 has to continue to serve 4.8 kV delta load. The current CNPI plans for voltage conversion entail Station 12 serving 4.8 kV delta load for another 20 years.

Given the above factors, CNPI decided that the overall investment of $625,000 allocated for ongoing minor investments and prudent maintenance practices was a reasonable and appropriate approach to sustaining Station 12 for at least another 20 years, compared to the cost of constructing a new facility.

INTERROGATORY # 14 – Meters

CNPI – Fort Erie specific interrogatories

Ref: Exhibit 2/Tab 1/Schedule 1 and Exhibit 2/Tab 3/Schedule 1/Appendix A/ page 12 – Meters

CNPI provides the following table for meter capital expenditures in Fort Erie in two exhibits:

Year	2006 Actual	2007 Actual	2008 Bridge	2009 Test
Exhibit 2 / Tab 1 / Schedule 1 / page 2 Capital Expenditures	$ 90,899	$ 190,786	$ 137,292	$ 121,471
Exhibit 2 / Tab 3 / Schedule 1 / Appendix A / page 12 Investment	$ 122,000	$ 161,000	$ 137,000	$ 123,000

CNPI states: "Increased expenditure levels in 2007 Actual reflect an increased emphasis on meter change-outs to meet Measurement Canada reverification requirements. CNPI has delayed further meter changeouts until a decision is made regarding the smart meter technology that will be employed in the smart meter implementation planned for 2009. Once CNPI selects a technology and vendor, that smart meter specification will be used for future meter changeouts. This will avoid the incremental cost of installing conventional meters in 2008, then replacing them in 2009 with smart meters." With CNPI expecting that smart meter deployment will actually commence in 2009, the 2008 bridge and 2009 test year meter capital expenditures are higher than 2006 actuals.

a) Please explain the differences between the two exhibits as shown in the above table.

b) Please provide further explanation of meter capital expenditures by year, breaking out actual and forecast expenditures by:
   i) Wholesale meters
   ii) Residential meters
   iii) General Service < 50 kW non-interval meters
   iv) General Service, Intermediate and Large Use Interval meters.

c) What, if any, options has CNPI considered, to avoid capital expenditures for conventional meter expenditures until CNPI is authorized to and commences smart meter deployment.

d) Is CNPI making efforts to become authorized to deploy smart meters pursuant to O. Reg. 427/06 as amended on June 25, 2008? If yes, please provide further explanation.

e) Please provide CNPI's estimate of when it expects to begin smart meter deployment once authorized.

RESPONSE:

a) The differences between the two exhibits are a result of the difference between capital project orders used for managing the capital expenditures and the OEB asset classes.

The amounts shown in Exhibit 2/Tab 3/Schedule 1/Appendix A are the capital expenditures that the business has made through project orders. The project orders normally contain a number of different asset classes and include all expenditures made in the year but capitalized in the following year.

The amounts shown in Exhibit 2/Tab 1/Schedule 1 are the actual amounts capitalized in that particular year. These amounts consist of all or portions of numerous project orders and may also include intercompany transfers.

b) The requested information is provided in the table below.

	2006 Actual	2007 Actual	2008 Forecast	2009 Forecast
Wholesale	$0	$0	$0	$0
Residential	95,400	155,700	12,000	8,000
Gen. Service < 50 kW	18,500	4,400	2,500	3,000
Gen. Service, Intermediate, Large Use	8,100	900	500	1,000
TOTAL	**$122,000**	**$161,000**	**$15,000**	**$12,000**

Amounts for 2008 Bridge Year and 2009 Test year have been adjusted from what was previously included in the rate application . CNPI will be deploying Smart Meters and Automated Meter Infrastructure (AMI) in 2009, and is, therefore, reducing purchases of conventional residential meters in anticipation of the mass Smart Meter deployment.

c) In anticipation of Smart Meter/AMI deployment in 2009, to avoid capital expenditures for new meters CNPI deliberately scaled back on the purchase of conventional meters in 2008 and will do the same in 2009. CNPI also scaled back on 2008 meter changeouts for Measurement Canada reverification requirements and used available reverified meters as much as possible to avoid purchasing new meters. Measurement Canada was informed of CNPI plans in this regard. Reforecasted meter capital expenditures for 2008 and 2009 are shown in the table in response (b) above.

d) CNPI is part of the Niagara Erie Power Association (NEPA), a consortium comprising nine utilities in the Niagara Region that is pursuing a collective approach to Smart Meter/AMI implementation. NEPA engaged the services of Util-Assist, Inc. to facilitate the process, a service that Util-Assist is also providing to other utility consortiums in Ontario working towards Smart Meter/AMI implementation. NEPA has prepared technical and economic models for evaluating Smart Meter/AMI suppliers and installers and temporary Operational Data Storage (ODS) providers. Pursuant to O. Reg. 427/06, NEPA "piggybacked" on the London Hydro RFP process for selecting a Smart Meter/AMI supplier. The evaluation process was facilitated by London Hydro and overseen by a Fairness Commissioner authorized by the Ministry of Energy. As a result of this process, Sensus Technologies was selected as the Smart Meter/AMI supplier for the NEPA consortium. Progress to date on Smart Meter/AMI implementation can be summarized as follows:

- Sensus selected as Smart Meter/AMI supplier. Contract expected to be signed by December 31, 2008.
- Proposals for Installation services are currently being evaluated and a decision will be made following such evaluation.
- RFP issued for temporary ODS services.

e) By “piggybacking” on the London Hydro RFP process in accordance with the provisions of O. Reg. 427/06, the NEPA consortium and CNPI is authorized by the Ministry of Energy to deploy Smart Meter/AMI. CNPI expects to commence deployment in July 2009.

INTERROGATORY # 15 – Leasehold Improvements

CNPI – Fort Erie specific interrogatories

Ref: Exhibit 2/Tab 3/Schedule 1/Appendix A/pages 14-15 – Leasehold Improvements

CNPI projects a leasehold improvement of $189,000 in 2009 for the Fort Erie Service Centre. What is the lease term over which CNPI will be amortizing the leasehold improvement?

RESPONSE:

The lease term over which CNPI will be amortizing the leasehold improvement is five years. This is based on the OEB Accounting Procedures Handbook guidelines which provide that the amortization period be the shorter of the term of the lease or the service life of the asset.

INTERROGATORY # 16 - Service Quality and Reliability

CNPI – FE specific interrogatories

Ref: Exhibit 2/Tab 1/Schedule 1/Appendix B – Service Reliability

CNPI provides reliability performance for the years 2003 to 2007 inclusive in the appendix, but states that the statistics shown "excludes outages due to Loss of Supply and Major Storms".

a) Please provide CNPI's definition of what constitutes a Major Storm, and how reliability statistics are adjusted for such events.

b) Please provide reliability performance data for the Fort Erie service area in the following table format.

	All Causes of Interruptions			All Interruptions except for Loss of Supply (Cause Code 2)		
Year	SAIDI	SAIFI	CAIDI	SAIDI	SAIFI	CAIDI
2002						
2003						
2004						
2005						
2006						
2007						

c) Please indicate any reliability indicator and year where performance was out of standard, meaning that it was higher than the range of the previous years. For any such case, please provide an explanation for the decreased reliability and the actions taken by CNPI to address the issue.

RESPONSE:

(a) CNPI considers a Major Storm to be a significant weather event, such as a snow, ice, electrical, or wind storm, that results in major outages to the distribution system and/or damage to property. The determination of a Major Storm is presently one of judgment, and CNPI takes into account factors such as the number of customers affected, the duration of outages, and whether contractors or crews from other utilities were needed to assist with restoration efforts. For the period 2003 - 2007, the only such major event that was adjusted for in the reliability statistics was the October 2006 Natural Disaster (snowstorm). For the data presented in the referenced Appendix, cumulative customer-hours of interruption and customer-interruptions as a result of this Disaster were deducted from the annual totals for 2006, resulting in adjusted reliability indices.

Outage data that CNPI formally submits to the OEB is collated and presented in accordance with OEB guidelines, so those submissions reflect all outages regardless of cause. In the Application, CNPI was attempting to illustrate its reliability performance over several years without the influence of major factors, such as major storms and loss of supply, that are beyond the control of CNPI. CNPI is considering adopting the IEEE 2.5 Beta Methodology for defining Major Event Days, though this would be for the purposes of internal CNPI analysis only, as the OEB has no mechanism for defining Major Events for reliability purposes.

(b)

	All Causes of Interruptions			All Interruptions except for Loss of Supply (Cause Code 2)		
Year	SAIDI	SAIFI	CAIDI	SAIDI	SAIFI	CAIDI
2002	**15.15**	4.26	3.56	**15.15**	4.26	3.56
2003	6.51	4.87	1.34	4.17	3.66	1.14
2004	4.90	2.92	1.68	4.90	2.92	1.68
2005	2.67	3.10	0.86	2.67	3.10	0.86
2006	61.87	12.54	4.94	**61.68**	**12.06**	**5.11**
2007	3.95	3.13	1.26	3.95	3.13	1.26

(c) Any indices that are higher than the range of previous years' performance are highlighted in bold in the "All Interruptions except for Loss of Supply" section of the Table, as CNPI has no control over Loss of Supply events. The only such instances occurred in 2006, where SAIDI, SAIFI, and CAIDI all were in excess of previous years' ranges. This was because of the severe impact of the October 2006 Natural Disaster.

INTERROGATORY # 17 – Meters

CNPI – Port Colborne specific interrogatories

Ref: Exhibit 2/Tab 3/Schedule 1/Appendix A/page 91 – Meters

CNPI provides the following table for meter capital expenditures, excluding smart meters:

Year	**2006 Actual**	**2007 Actual**	**2008 Bridge**	**2009 Test**
Investment ($)	71,000	70,000	130,000	101,000

CNPI states: "Increased capital expenditure levels for 2008 Bridge and 2009 Test Years reflect an increased emphasis on meter changeouts to meet Measurement Canada reverification requirements. CNPI has delayed further meter changeouts until a decision is made regarding the smart meter technology that will be employed in the smart meter implementation planned for 2009. Once CNPI selects a technology and vendor, the smart meter specifications will be used for future meter changeouts. This will avoid the incremental cost of installing conventional meters in 2008, then replacing them in 2009 with smart meters."

a) Please provide further explanation for the increased 2008 and 2009 conventional meter capital expenditures, and reconcile the increases versus CNPI's statement to defer meter changeouts until it starts smart meter deployment, which CNPI has also stated that it has planned to begin in 2009.

b) What, if any, options has CNPI considered to avoid capital expenditures for conventional meter replacements until CNPI is authorized to and commences smart meter deployment?

RESPONSE:

(a) In its Application, CNPI-PC quoted originally budgeted meter capital expenditures for 2008 and 2009. At the time these budgets were prepared, plans for Smart Meter deployment were still in development and schedules were very tentative. In its Application, CNPI-PC omitted to reforecast the 2008 and 2009 amounts to reflect the fact that CNPI-PC has deliberately scaled back on the purchase of conventional meters in 2008 and will do the same in 2009. CNPI also scaled back on 2008 meter changeouts for Measurement Canada reverification requirements and used available reverified meters as much as possible to avoid purchasing new meters. Measurement Canada was informed of CNPI-PC plans in this regard. The CNPI-PC approach is reasonable and appropriate to reduce meter capital expenditures as much as possible in anticipation of Smart Meter deployment in 2009.

Correct reforecasted Meter Capital expenditure amounts for 2008 and 2009 are as follows:

- 2008: $9,000
- 2009: $7,000

(b) As explained in (a) above, CNPI-PC has and is taking action to minimize capital expenditures for conventional meter replacements until CNPI-PC deploys Smart Meter/Automated Metering Infrastructure (AMI). With its affiliates CNPI-FE and CNPI-EOP, CNPI-PC is part of the Niagara Erie Power Association (NEPA), a consortium comprising nine utilities in the Niagara Region that is pursuing a collective approach to Smart Meter/AMI implementation. NEPA engaged the services of Util-Assist, Inc. to facilitate the process, a service that Util-Assist is also providing to other utility consortiums in Ontario working towards Smart Meter/AMI implementation. NEPA has prepared technical and economic models for evaluating Smart Meter/AMI suppliers and installers and temporary Operational Data Storage (ODS) providers.

Pursuant to O. Reg. 427/06, NEPA “piggybacked” on the London Hydro RFP process for selecting a Smart Meter/AMI supplier. The evaluation process was facilitated by London Hydro and overseen by a Fairness Commissioner authorized by the Ministry of Energy. As a result of this process, Sensus Technologies was selected as the Smart Meter/AMI supplier for the NEPA consortium. Progress to date on Smart Meter/AMI implementation can be summarized as follows:

- Sensus selected as Smart Meter/AMI supplier. Contract expected to be signed by December 31, 2008.
- Proposals for Installation services are currently being evaluated and a decision will be made following such evaluation.
- RFP issued for temporary ODS services.

By “piggybacking” on the London Hydro RFP process in accordance with the provisions of O. Reg. 427/06, the NEPA consortium and CNPI-PC is authorized by the Ministry of Energy to deploy Smart Meter/AMI. CNPI-PC expects to commence deployment in July 2009.

INTERROGATORY # 18 – Service Quality & Reliability

CNPI–PC specific interrogatories

Ref: Exhibit 2/Tab 1/Schedule 1/Appendix B – Service Reliability

On Page 2 of the Exhibit, CNPI provides reliability statistics for 2005 to 2007 excluding outages due to Loss of Supply and Major Storms.

a) Please provide reliability performance data for the Fort Erie service area in the following table format.

	All Causes of Interruptions			All Interruptions except for Loss of Supply (Cause Code 2)		
Year	SAIDI	SAIFI	CAIDI	SAIDI	SAIFI	CAIDI
2002						
2003						
2004						
2005						
2006						
2007						

b) Please indicate any reliability indicator and year where performance was out of standard, meaning that it was higher than the range of the previous years.

c) Please define what CNPI defines as a Major Storm for the purposes of excluding the associated outage statistics from reported reliability performance.

d) CNPI states that " … both SAIDI and SAIFI indices in Port Colborne have increased over the three-year period. This indicates that outages are occurring more frequently in Port Colborne partially as a result of equipment failures but also because of an increase in bad weather activity over the last few years." Please provide a breakdown of all outages, outage duration, and customers affected, with respect to the Cause Codes listed in Table 15.2 of the *Electricity Distribution Rate Handbook,* for all outages in 2006. 2007, and 2008 year-to-date.

RESPONSE:

(a)

	All Causes of Interruptions			All Interruptions except for Loss of Supply (Cause Code 2)		
Year	SAIDI	SAIFI	CAIDI	SAIDI	SAIFI	CAIDI
2002	N/A	N/A	N/A	0.58	1.36	0.43
2003	2.63	1.80	1.46	**2.27**	**1.68**	**1.35**
2004	0.71	0.26	2.72	0.71	0.26	**2.72**
2005	3.94	3.86	1.02	**3.94**	**3.86**	1.02

2006	14.77	5.86	2.52	**14.77**	**5.86**	2.52
2007	3.57	4.95	0.72	3.51	4.87	0.72

(b) Any indices that are higher than the range of previous years' performance are highlighted in bold in the "All Interruptions except for Loss of Supply" section of the Table, as CNPI has no control over Loss of Supply events.

(c) CNPI does not presently have a formal definition for what constitutes a Major Storm. CNPI considers a Major Storm to be a significant natural phenomenon, such as a snow, ice, electrical, or wind storm, that results in major outages to the distribution system. Defining when such an event occurs is presently one of judgement, and CNPI takes into account factors such as the number of customers affected, the duration of outages, and whether contractors or crews from other utilities were needed to assist with restoration efforts. For the period 2003-2007, the only such major events for which data was adjusted were the October 2006 Natural Disaster (snowstorm) and a windstorm in December 2006. For the data presented in the referenced Appendix, cumulative customer-hours of interruption and customer-interruptions as a result of these storms were deducted from the annual totals for 2006, resulting in adjusted reliability indices.

Outage data that CNPI formally submits to the OEB is collated and presented in accordance with OEB guidelines, so those submissions reflect all outages regardless of cause. In its Application, CNPI was attempting to illustrate its reliability performance over several years without the influence of major factors, such as storms and loss of supply, that are beyond the control of CNPI. CNPI is considering adopting the IEEE 2.5 Beta Methodology for defining Major Event Days, though this would be for the purposes of internal CNPI analysis only, as the OEB presently has no mechanism for defining Major Events for reliability purposes.

(d) The requested data in the prescribed format is attached to this response as Attachment A.

ATTACHMENT A: INTERROGATORY # 18

2006 Outage Data					
Date	Time Off	Time On	Outage Duration	# of Customers Affected	Cause Code
July 12 2006	9:12:00	11:50:00	2:38:00	95	0
August 5 2006	6:33:00	8:00:00	1:27:00	1	0
August 15 2006	08:30:00	10:20:00	1:50:00	1149	0
August 18 2006	09:30:00	10:15:00	0:45:00	1	0
August 25 2006	00:45:00	02:00:00	1:15:00	8	0
January 17 2006	17:31:00	17:46:00	0:15:00	299	1
September 21 2006	13:00:00	13:45:00	0:45:00	1	1
October 5 2006	14:00:00	14:30:00	0:30:00	1	1
November 23 2006	13:00:00	14:00:00	1:00:00	1	1
January 18 2006	14:10:00	16:47:00	2:37:00	4	3
January 18 2006	17:47:00	19:07:00	1:20:00	4746	3
July 12 2006	6:40:00	7:45:00	1:05:00	60	3
July 26 2006	10:35:00	10:50:00	0:15:00	1	3
August 14 2006	18:00:00	18:22:00	0:22:00	12	3
September 13 2006	02:27:47	03:30:42	1:02:55	1606	3
September 25 2006	19:03:00	20:45:00	1:42:00	2	3
January 13 2006	18:20:00	19:30:00	1:10:00	2	4
January 17 2006	16:16:00	16:30:00	0:14:00	216	4
March 13 2006	7:10:00	7:15:00	0:05:00	2012	4
March 13 2006	16:20:00	17:15:00	0:55:00	1	4
March 13 2006	18:40:00	19:17:00	0:37:00	1	4
April 3 2006	15:40:00	17:17:00	1:37:00	2	4
June 30 2006	15:00:00	16:34:00	1:34:00	4736	4
July 10 2006	6:30	7:25	0:55:00	14	4
August 3 2006	23:00:00	1:15:00 AM	2:15:00	1	4
October 1 2006	16:59:00	19:10:00	2:11:00	1	4
October 4 2006	07:33:00	08:50:00	1:17:00	2012	4
January 17 2006	16:31:00	17:46:00	1:15:00	216	5
January 17 2006	19:22:00	19:37:00	0:15:00	88	5
January 18 2006	19:09:00	19:17:00	0:08:00	6661	5
January 18 2006	17:47:00	20:53:00	3:06:00	4746	5
February 9 2006	17:30:00	20:00:00	2:30:00	1	5
May 10 2006	17:30:00	18:42:00	1:12:00	1	5
May 26 2006	16:07:00	16:55:00	0:48:00	1	5
May 31 2006	18:20:00	19:25:00	1:05:00	12	5
June 6 2006	18:40:00	20:17:00	1:37:00	1	5
July 27 2006	16:10:00	17:10:00	1:00:00	2	5
July 28 2006	10:30:00	13:30:00	3:00:00	200	5
July 31 2006	15:30:00	16:45:00	1:15:00	15	5
August 3 2006	12:00:00	14:30:00	2:30:00	1	5
August 6 2006	22:01:00	23:15:00	1:14:00	1	5
August 29 2006	12:45:00	13:25:00	0:40:00	20	5
September 2 2006	18:00:00	22:00:00	4:00:00	2	5
September 11 2006	09:32:00	10:03:00	0:31:00	1	5
September 11 2006	13:07:00	13:50:00	0:43:00	2	5
September 20 2006	09:45:00	10:00:00	0:15:00	10	5
September 24 2006	12:30:00	14:00:00	1:30:00	100	5
October 11 2006	15:53:00	16:49:00	0:56:00	12	5
October 12 2006	12:10:00	12:20:00	0:10:00	1	5
October 28 2006	17:50:00	21:15:00	3:25:00	15	5
November 4 2006	06:45:00	07:40:00	0:55:00	1	5
November 16 2006	15:00:00	16:30:00	1:30:00	2	5
November 19 2006	09:17:00	11:12:00	1:55:00	25	5
December 6 2006	18:32:00	19:32:00	1:00:00	12	5

Date	Time Off	Time On	Outage Duration	# of Customers Affected	Cause Code
December 12 2006	22:20:00	22:38:00	0:18:00	1	5
October 12 2006	N/A	N/A	01:36	4,736	6
October 12 2006	N/A	N/A	06:41	983	6
October 12 2006	N/A	N/A	15:00	99	6
October 12 2006	N/A	N/A	01:33	338	6
October 12 2006	N/A	N/A	01:33	380	6
October 12 2006	N/A	N/A	01:33	85	6
October 12 2006	N/A	N/A	01:34	805	6
October 12 2006	N/A	N/A	00:12	338	6
October 13 2006	N/A	N/A	07:23	1,425	6
October 13 2006	N/A	N/A	00:13	2,012	6
October 13 2006	N/A	N/A	00:05	983	6
October 13 2006	N/A	N/A	00:12	983	6
October 13 2006	N/A	N/A	14:22	983	6
October 13 2006	N/A	N/A	13:48	662	6
October 13 2006	N/A	N/A	14:46	202	6
October 13 2006	N/A	N/A	14:46	285	6
October 14 2006	N/A	N/A	34:28	59	6
October 14 2006	N/A	N/A	60:30	93	6
October 14 2006	N/A	N/A	36:38	92	6
October 14 2006	N/A	N/A	43:32	70	6
October 14 2006	N/A	N/A	41:10	69	6
October 14 2006	N/A	N/A	44:21	119	6
October 14 2006	N/A	N/A	36:00	61	6
October 14 2006	N/A	N/A	57:07	102	6
December 1 2006	12:20:00	13:00:00	0:40:00	10	6
December 1 2006	N/A	N/A	02:45	2012	6
December 1 2006	N/A	N/A	02:20	2012	6
December 1 2006	N/A	N/A	02:27	983	6
December 1 2006	N/A	N/A	01:45	413	6
December 1 2006	N/A	N/A	01:45	549	6
December 2 2006	N/A	N/A	08:13	73	6
August 28 2006	16:49:00	18:20:00	1:31:00	1	7
September 13 2006	02:27:47	03:30:42	1:02:55	2	8
March 28 2006	16:27:00	17:23:00	0:56:00	2012	9
July 12 2006	9:12:00	10:15:00	1:03:00	92	9
Sept. 14 2006	21:50:00	22:50:00	1:00:00	1	9
November 7 2006	20:00:00	22:50:00	2:50:00	12	9

2007 Outage Data					
Date	**Time Off**	**Time On**	**Outage Duration**	**# of Customers Affected**	**Cause Code**
July 4 2007	07:07:00	08:40:00	1:33:00	2012	0
July 4 2007	08:40:00	08:42:00	0:02:00	1494	0
July 4 2007	08:42:00	08:58:00	0:16:00	202	0
August 1 2007	17:10:00	18:30:00	1:20:00	78	0
October 21 2007	10:57:00	12:07:00	1:10:00	10	0
January 16 2007	13:00:00	14:15:00	1:15:00	1	1
May 1 2007	13:08:00	13:10:00	0:02:00	2	1
May 1 2007	13:08:00	13:17:00	0:09:00	83	1
May 29 2007	09:20:00	13:20:00	4:00:00	1	1
July 6 2007	09:45:00	10:02:00	0:17:00	11	1
July 10 2007	09:30:00	09:37:00	0:07:00	11	1
July 12 2007	10:15:00	11:00:00	0:45:00	1	1
July 24 2007	11:00:00	11:45:00	0:45:00	2	1
October 4 2007	15:14:12	15:26:00	0:11:48	1104	1
November 9 2007	13:15:00	14:30:00	1:15:00	10	1
November 12 2007	10:35:00	12:35:00	2:00:00	10	1
November 15 2007	14:00:00	14:30:00	0:30:00	1	1
November 16 2007	09:30:00	14:15:00	4:45:00	1	1
November 19 2007	10:35:00	11:00:00	0:25:00	15	1
November 23 2007	09:35:00	11:00:00	1:25:00	4	1
November 27 2007	12:50:00	13:20:00	0:30:00	11	1
November 27 2007	15:34:00	15:45:00	0:11:00	22	1
November 28 2007	10:38:00	12:18:00	1:40:00	8	1
November 28 2007	14:30:00	15:30:00	1:00:00	13	1
November 29 2007	10:40:00	12:00:00	1:20:00	14	1
December 5 2007	13:30:00	14:45:00	1:15:00	8	1
December 7 2007	10:30:00	12:30:00	2:00:00	9	1
December 10 2007	12:45:00	13:45:00	1:00:00	14	1
December 11 2007	10:30:00	11:30:00	1:00:00	1	1
December 12 2007	12:40:00	13:50:00	1:10:00	11	1
December 13 2007	10:15:00	11:45:00	1:30:00	12	1
April 1 2007	08:47:00	09:36:00	0:49:00	4	2
January 30 2007	18:05:00	20:25:00	2:20:00	1	3
February 3 2007	16:44:00	17:42:00	0:58:00	4736	3
March 24 2007	11:26:00	12:45:00	1:19:00	73	3
June 8 2007	13:10:00	13:56:00	0:46:00	6	3
June 13 2007	10:46:00	14:30:00	3:44:00	2	3
June 19 2007	16:30:00	17:10:00	0:40:00	50	3
June 27 2007	17:30:00	18:10:00	0:40:00	1	3
July 4 2007	09:30:00	10:15:00	0:45:00	25	3
September 7 2007	21:15:00	22:45:00	1:30:00	386	3
September 11 2007	21:30:00	04:00:00	6:30:00	86	3
September 11 2007	21:30:00	18:15:00	20:45:00	1	3
September 11 2007	21:30:00	02:40:00	5:10:00	10	3
September 11 2007	21:00:00	20:00:00	23:00:00	1	3
September 11 2007	21:00:00	20:00:00	23:00:00	1	3
September 12 2007	01:00:00	02:30:00	1:30:00	30	3
November 1 2007	08:40:00	09:38:00	0:58:00	40	3
November 8 2007	16:10:00	16:30:00	0:20:00	1	3
November 9 2007	12:50:00	11:25 (Nov 12)	70:35:00	1	3
November 27 2007	16:00:00	17:00:00	1:00:00	47	3
November 30 2007	15:00:00	16:00:00	1:00:00	2	3
November 30 2007	12:50:00	13:20:00	0:30:00	1	3

Date	Time Off	Time On	Outage Duration	# of Customers Affected	Cause Code
December 2 2007	06:20:00	07:40:00	1:20:00	457	3
April 26 2007	16:30:00	18:35:00	2:05:00	83	4
May 10 2007	05:45:00	08:05:00	2:20:00	50	4
June 8 2007	17:08:00	22:00:00	4:52:00	25	4
June 8 2007	17:08:00	21:26:00	4:18:00	4	4
June 8 2007	17:29:20	18:56:00	1:26:40	2012	4
June 8 2007	18:56:00	19:23:00	0:27:00	202	4
June 8 2007	19:20:00	20:00:00	0:40:00	1	4
June 8 2007	22:20:00	23:30:00	1:10:00	1	4
June 8 2007	21:00:00	22:40:00	1:40:00	1	4
June 11 2007	09:45:00	10:35:00	0:50:00	1	4
June 19 2007	16:30:00	17:50:00	1:20:00	25	4
August 23 2007	10:30:00	11:30:00	1:00:00	31	4
September 11 2007	23:30:00	01:30:00	2:00:00	12	4
September 11 2007	22:00:00	00:00:00	2:00:00	12	4
September 11 2007	21:00:00	22:00:00	1:00:00	20	4
September 12 2007	02:00:00	03:15:00	1:15:00	14	4
September 12 2007	01:30:00	02:00:00	0:30:00	30	4
September 12 2007	02:00:00	03:15:00	1:15:00	20	4
September 25 2007	17:00:00	17:30:00	0:30:00	1	4
September 25 2007	22:10:00	23:30:00	1:20:00	1	4
October 7 2007	00:53:00	00:59:00	0:06:00	2021	4
October 7 2007	01:00:00	06:00:00	5:00:00	1	4
October 7 2007	01:00:00	02:30:00	1:30:00	1	4
October 7 2007	09:30:00	10:17:00	0:47:00	1	4
October 10 2007	18:00:00	21:30:00	3:30:00	1	4
January 4 2007	12:30:00	13:30:00	1:00:00	2012	5
January 4 2007	12:30:00	14:12:00	1:42:00	119	5
January 5 2007	16:44:00	17:44:00	1:00:00	1	5
January 8 2007	21:55:00	23:00:00	1:05:00	10	5
January 21 2007	13:30:00	17:10:00	3:40:00	1	5
January 23 2007	10:15:00	11:55:00	1:40:00	1	5
February 1 2007	21:26:00	01:26:00	4:00:00	1	5
February 15 2007	09:05:00	10:30:00	1:25:00	2	5
February 16 2007	22:20:00	23:40:00	1:20:00	2	5
February 18 2007	15:54:00	17:20:00	1:26:00	1	5
February 20 2007	22:10:00	23:20:00	1:10:00	83	5
February 23 2007	03:00:00	03:05:00	0:05:00	1	5
March 2 2007	21:44:00	23:00:00	1:16:00	2	5
March 2 2007	10:02:00	10:45:00	0:43:00	1	5
March 5 2007	16:05:00	18:00:00	1:55:00	1	5
March 5 2007	13:47:00	14:30:00	0:43:00	75	5
March 14 2007	00:00:00	00:30:00	0:30:00	1	5
March 16 2007	08:00:00	08:25:00	0:25:00	1	5
March 23 2007	12:45:00	13:15:00	0:30:00	1	5
March 30 2007	22:00:00	22:05:00	0:05:00	1	5
April 10 2007	12:15:00	12:25:00	0:10:00	1	5
April 10 2007	15:50:00	16:10:00	0:20:00	1	5
April 14 2007	09:00:00	11:15:00	2:15:00	1	5
April 15 2007	13:15:00	14:00:00	0:45:00	1	5
April 18 2007	18:35:00	19:05:00	0:30:00	2	5
April 22 2007	16:00:00	19:05:00	3:05:00	1	5
May 1 2007	03:08:00	04:15:00	1:07:00	6	5
May 7 2007	11:54:39	12:35:11	0:40:32	2012	5
May 8 2007	15:10:00	15:25:00	0:15:00	1	5
May 16 2007	20:07:00	20:07:03	0:00:03	983	5

Date	Time Off	Time On	Outage Duration	# of Customers Affected	Cause Code
May 16 2007	21:40:00	22:00:00	0:20:00	56	5
May 16 2007	20:07:00	22:00:00	1:53:00	27	5
May 22 2007	11:40:00	12:10:00	0:30:00	1	5
May 29 2007	17:00:00	18:00:00	1:00:00	1	5
June 5 2007	10:10:00	10:40:00	0:30:00	2	5
June 8 2007	10:16:00	10:58:00	0:42:00	4737	5
June 8 2007	10:58:00	11:36:00	0:38:00	1620	5
June 8 2007	11:36:00	11:38:00	0:02:00	1608	5
June 14 2007	13:10:00	13:40:00	0:30:00	1	5
June 15 2007	18:00:00	18:30:00	0:30:00	1	5
June 17 2007	12:45:00	14:29:00	1:44:00	10	5
June 22 2007	13:45:00	14:30:00	0:45:00	1	5
June 26 2007	11:40:00	11:55:00	0:15:00	1	5
July 4 2007	09:00:00	09:30:00	0:30:00	1	5
July 15 2007	04:10:00	05:50:00	1:40:00	6	5
July 16 2007	10:25:00	11:00:00	0:35:00	1	5
July 17 2007	13:05:00	13:15:00	0:10:00	1	5
July 26 2007	17:18:00	21:50:00	4:32:00	6	5
July 27 2007	19:00:00	20:35:00	1:35:00	13	5
August 1 2007	17:05:00	17:25:00	0:20:00	1	5
August 26 2007	08:40:00	09:40:00	1:00:00	3	5
September 6 2007	12:10:00	12:50:00	0:40:00	1	5
September 7 2007	09:40:00	10:00:00	0:20:00	1	5
September 15 2007	14:15:00	15:35:00	1:20:00	1	5
September 21 2007	13:05:00	13:25:00	0:20:00	1	5
September 23 2007	11:45:00	13:00:00	1:15:00	67	5
October 4 2007	14:26:13	14:35:00	0:08:47	25	5
October 4 2007	14:35:00	14:36:49	0:01:49	477	5
October 4 2007	14:36:49	15:26:00	0:49:11	627	5
October 5 2007	13:55:00	14:10:00	0:15:00	1	5
October 30 2007	21:30:00	21:40:00	0:10:00	1	5
November 1 2007	10:40:00	11:00:00	0:20:00	1	5
November 5 2007	15:01:00	16:15:00	1:14:00	3	5
November 5 2007	23:55:00	00:15:00	0:20:00	1	5
November 6 2007	14:00:00	15:28:00	1:28:00	55	5
November 12 2007	12:40:00	13:30:00	0:50:00	2	5
November 20 2007	14:30:00	14:43:00	0:13:00	1	5
November 22 2007	23:25:50	00:29:04	1:03:14	627	5
November 23 2007	16:55:00	17:15:00	0:20:00	1	5
November 24 2007	14:00:00	15:30:00	1:30:00	10	5
November 26 2007	11:15:00	11:45:00	0:30:00	1	5
November 26 2007	15:20:00	15:45:00	0:25:00	1	5
November 26 2007	22:10:00	22:25:00	0:15:00	1	5
November 29 2007	10:00:00	10:30:00	0:30:00	1	5
November 30 2007	15:00:00	15:50:00	0:50:00	15	5
December 23 2007	13:00:00	13:30:00	0:30:00	1	5
January 15 2007	18:25:00	18:33:00	0:08:00	2012	6
January 15 2007	12:36:00	18:28:00	5:52:00	4	6
January 15 2007	19:54:00	19:58:00	0:04:00	4	6
January 15 2007	09:43:00	10:26:00	0:43:00	4736	6
January 15 2007	15:00:00	16:15:00	1:15:00	1	6
January 15 2007	15:15:00	16:23:00	1:08:00	1	6
January 15 2007	16:10:00	16:40:00	0:30:00	1	6
January 15 2007	16:10:00	23:00:00	6:50:00	1	6
January 16 2007	00:05:00	02:30:00	2:25:00	31	6
January 16 2007	03:15:00	03:46:00	0:31:00	61	6
March 26 2007	15:40:00	20:05:00	4:25:00	15	6

Date	Time Off	Time On	Outage Duration	# of Customers Affected	Cause Code
September 11 2007	21:00:00	Midnight Sept. 12	27:00:00	14	6
September 11 2007	21:00:00	13:45 Sept. 13	16:45:00	12	6
September 11 2007	21:00:00	Midnight Sept. 12	27:00:00	3	6
September 11 2007	21:00:00	13:45 Sept. 13	16:45:00	14	6
September 12 2007	00:40:00	01:25:00	0:45:00	9	6
November 5 2007	15:00:00	16:00:00	1:00:00	12	6
November 30 2007	14:40:00	16:00:00	1:20:00	12	6
December 24 2007	18:25:00	18:35:00	0:10:00	1	7
January 16 2007	12:00:00	12:49:00	0:49:00	1	8
July 29 2007	13:50:00	14:38:00	0:48:00	99	8
October 4 2007	13:51:20	14:26:13	0:34:53	2021	8
May 1 2007	02:00:00	09:00:00	7:00:00	1	9
May 15 2007	02:50:00	03:45:00	0:55:00	1	9
June 10 2007	21:15:00	22:00:00	0:45:00	1	9
July 3 2007	09:40:00	10:20:00	0:40:00	2	9
July 7 2007	06:00:00	07:15:00	1:15:00	10	9
July 23 2007	09:00:00	09:50:00	0:50:00	1	9
July 27 2007	16:21:00	16:41:00	0:20:00	2012	9
July 29 2007	14:10:00	14:10:03	0:00:03	983	9
July 29 2007	14:10:00	15:30:00	1:20:00	10	9
August 5 2007	22:30:00	00:55:00	2:25:00	1	9
August 7 2007	11:50:00	12:00:00	0:10:00	1	9
August 21 2007	09:10:00	10:20:00	1:10:00	1	9
August 24 2007	23:35:00	00:45:00	1:10:00	2	9
September 1 2007	17:30:00	19:00:00	1:30:00	1	9
September 2 2007	07:45:00	08:45:00	1:00:00	4	9
September 11 2007	10:30:00	11:45:00	1:15:00	1	9
September 20 2007	16:14:11	17:40:51	1:26:40	805	9
September 20 2007	17:40:51	21:36:00	3:55:09	4	9
October 4 2007	15:20:00	16:00:00	0:40:00	1	9
October 19 2007	09:00:00	10:30:00	1:30:00	1	9
November 5 2007	06:03:00	06:47:00	0:44:00	1304	9
November 5 2007	06:03:00	06:47:00	0:44:00	717	9
November 5 2007	06:47:00	08:05:00	1:18:00	1304	9
November 5 2007	08:05:00	11:00:00	2:55:00	75	9
November 17 2007	11:30:00	12:30:00	1:00:00	54	9
November 18 2007	13:20:00	16:00:00	2:40:00	1	9
December 24 2007	17:45:00	20:36:00	2:51:00	30	9

2008 Outage Data					
Date	Time Off	Time On	Outage Duration	# of Customers Affected	Cause Code
February 19, 2008	10:40	10:45:00	0:05:00	1	0
May 17, 2008	20:21	21:30:00	1:08:53	30	0
July 25, 2008	13:30	15:30:00	2:00:00	9	1
July 25, 2008	9:30	11:00:00	1:30:00	1	1
July 30, 2008	13:25	14:40:00	1:15:00	29	1
July 8, 2008	11:15	14:55:00	3:40:00	4	1
July 4, 2008	12:30	15:30:00	3:00:00	14	1
June 2, 2008	13:35	14:20:00	0:45:00	1	1
July 9, 2008	13:00	14:00:00	1:00:00	4	1
March 12, 2008	11:00	16:00:00	5:00:00	1	1
February 29, 2008	12:35	14:00:00	1:25:00	1	1
April 2, 2008	10:00	13:00:00	3:00:00	6	1
February 28, 2008	11:35	12:05:00	0:30:00	5	1
May 2, 2008	11:00	11:45:00	0:45:00	3	1
January 8, 2008	12:45	13:10:30	0:25:30	2	1
March 11, 2008	13:25	15:15:00	1:50:00	1	1
March 17, 2008	10:00	16:00:00	6:00:00	8	1
March 14, 2008	13:28	16:05:00	2:37:00	8	1
March 18, 2008	10:20	16:10:00	5:50:00	8	1
June 4, 2008	13:35	13:50:00	0:15:00	1	1
May 21, 2008	13:30	14:30:00	1:00:00	19	1
May 28, 2008	14:10	15:30:00	1:20:00	19	1
September 25, 2008	11:15	11:45:00	0:30:00	10	1
September 25, 2008	8:11	14:44:00	6:33:00	7	1
May 26, 2008	15:00	15:40:00	0:40:00	1	1
May 23, 2008	10:45	13:00:00	2:15:00	15	1
March 10, 2008	9:20	9:27:00	0:07:00	1429	1
September 25, 2008	13:00	14:30:00	1:30:00	10	1
September 24, 2008	8:10	14:25:00	6:15:00	7	1
August 14, 2008	10:30	12:00:00	1:30:00	14	1
August 12, 2008	9:15	10:00:00	0:45:00	1	1
August 13, 2008	10:10	17:15:00	7:05:00	1	1
August 18, 2008	9:05	9:40:00	0:35:00	3	1
August 15, 2008	9:30	12:20:00	2:50:00	1	1
August 15, 2008	10:19	10:22:00	0:03:00	1430	1
June 28, 2008	17:20	17:28:00	0:08:00	1	1
March 10, 2008	9:20	17:35:00	8:15:00	1	1
September 20, 2008	7:00	11:20:00	4:20:00	1	1
June 18, 2008	2:15	3:30:00	1:15:00	4	1
August 28, 2008	11:00	13:30:00	2:30:00	1	1
June 22, 2008	8:10	15:10:00	7:00:00	1	1
August 15, 2008	9:45	10:22:00	0:37:00	2016	2
October 26, 2008	22:10	22:50:00	0:40:00	3	3
June 13, 2008	18:30	21:00:00	2:30:00	6	3
March 21, 2008	17:15	17:35:00	0:20:00	69	3
January 9, 2008	13:30	15:40:00	2:10:00	3	3

February 5, 2008	16:15	18:00:00	1:45:00	140	3
January 10, 2008	15:00	15:20:00	0:20:00	4	3
September 22, 2008	12:32	12:35:00	0:03:00	27	3
June 10, 2008	5:30	7:00:00	1:30:00	8	3
June 10, 2008	14:38	15:50:00	1:12:00	2	3
January 30, 2008	11:05	18:26:00	7:21:00	4	3
September 14, 2008	21:00	23:00:00	2:00:00	50	3
September 14, 2008	23:04	23:35:00	0:30:11	4735	3
January 30, 2008	1:00	5:00:00	4:00:00	50	3
September 14, 2008	20:15	21:00:00	0:45:00	20	3
June 10, 2008	1:00	5:00:00	4:00:00	50	4
June 9, 2008	23:14	23:14:34	0:00:22	393	4
May 31, 2008	9:50	11:00:00	1:10:00	1	4
June 9, 2008	23:56	1:39:00	1:43:00	800	4
August 2, 2008	5:45	7:25:00	1:40:00	3	4
September 6, 2008	21:24	23:05:00	1:41:00	1	4
August 2, 2008	7:15	8:15:00	1:00:00	9	4
June 9, 2008	12:10	13:00:00	0:50:00	50	4
August 2, 2008	7:15	8:10:00	0:55:00	1	4
August 2, 2008	5:45	6:55:00	1:10:00	1	4
August 7, 2008	18:50	23:00:00	4:10:00	21	4
September 9, 2008	3:20	4:30:00	1:10:00	1	4
June 10, 2008	9:22	12:30:00	3:08:00	1	4
June 10, 2008	7:30	9:00:00	1:30:00	4	4
February 6, 2008	17:50	18:20:00	0:30:00	2	5
January 27, 2008	8:00	9:20:00	1:20:00	12	5
June 15, 2008	12:00	15:00:00	3:00:00	2	5
February 17, 2008	21:29	22:10:00	0:41:00	1	5
January 31, 2008	11:05	11:20:00	0:15:00	1	5
January 25, 2008	20:15	21:00:00	0:45:00	2	5
February 21, 2008	14:30	15:00:00	0:30:00	1	5
February 5, 2008	11:50	12:10:00	0:20:00	1	5
February 6, 2008	7:30	8:25:00	0:55:00	6	5
June 16, 2008	18:00	18:18:00	0:18:00	21	5
April 5, 2008	11:15	12:30:00	1:15:00	1	5
February 20, 2008	14:40	15:00:00	0:20:00	1	5
January 12, 2008	9:50	11:20:00	1:30:00	1	5
February 28, 2008	13:00	13:40:00	0:40:00	27	5
June 23, 2008	10:45	10:55:00	0:10:00	10	5
January 22, 2008	14:10	14:30:00	0:20:00	2	5
April 27, 2008	19:09	3:00:00	7:51:00	70	5
October 27, 2008	13:00	13:25:00	0:25:00	2	5
January 12, 2008	19:00	21:40:00	2:40:00	2	5
February 17, 2008	18:25	20:05:00	1:40:00	7	5
October 23, 2008	10:10	10:30:00	0:20:00	1	5
March 3, 2008	20:47	21:50:00	1:03:00	1	5
January 16, 2008	11:45	14:50:00	3:05:00	61	5
October 7, 2008	7:50	8:45:00	0:55:00	1	5
October 26, 2008	12:05	12:45:00 PM	0:40:00	1	5

February 1, 2008	12:50	13:05:00	0:15:00	1	5
February 1, 2008	19:10	20:05:00	0:55:00	1	5
September 3, 2008	18:06	19:15:00	1:09:00	1	5
September 4, 2008	21:53	23:00:00	1:07:00	12	5
September 16, 2008	14:41	15:00:00	0:19:00	1	5
September 17, 2008	18:10	18:40:00	0:30:00	1	5
July 3, 2008	22:00	23:10:00	1:10:00	1	5
March 7, 2008	12:30	14:15:00	1:45:00	1	5
May 28, 2008	8:21	10:00:00	1:38:06	5	5
October 7, 2008	9:20	10:00:00	0:40:00	1	5
April 25, 2008	9:40	9:45:00	0:05:00	1	5
May 3, 2008	23:05	0:35:00	1:30:00	3	5
February 20, 2008	14:30	15:50:00	1:20:00	1	5
June 9, 2008	18:30	19:30:00	1:00:00	3	5
October 1, 2008	12:50	13:15:00	0:25:00	2	5
May 28, 2008	8:21	8:21:55	0:00:01	256	5
March 19, 2008	20:23	21:45:00	1:22:00	16	5
July 28, 2008	16:30	16:45:00	0:15:00	1	5
April 25, 2008	10:34	11:00:00	0:26:00	5	5
September 6, 2008	7:53	9:40:00	1:47:00	9	5
January 9, 2008	13:30	13:55:00	0:25:00	18	5
October 10, 2008	12:55	13:05:00	0:10:00	12	5
April 25, 2008	10:30	10:34:00	0:04:00	238	5
June 28, 2008	7:30	7:38:00	0:08:00	5	5
February 22, 2008	1:45	5:15:00	3:30:00	40	5
October 29, 2008	19:40	21:30:00	1:50:00	8	5
April 18, 2008	9:20	9:40:00	0:20:00	1	5
January 9, 2008	11:30	12:25:00	0:55:00	20	6
February 19, 2008	9:16	10:10:00	0:54:00	1	6
April 1, 2008	19:45	20:40:00	0:55:00	1	6
January 3, 2008	22:00	23:15:00	1:15:00	15	6
January 9, 2008	13:30	14:40:00	1:10:00	2	6
June 9, 2008	23:56	1:42:00	1:46:00	275	8
June 9, 2008	23:56	1:40:00	1:46:00	334	8
June 9, 2008	23:56	1:42:00	1:46:00	81	8
July 9, 2008	9:50	10:50:00	1:00:00	1	9
October 13, 2008	9:23	10:23:00	1:00:00	14	9
October 7, 2008	10:10	10:45:00	0:35:00	200	9
May 12, 2008	7:30	8:50:00	1:20:00	1	9
May 7, 2008	4:10	5:30:00	1:20:00	2	9
August 25, 2008	11:06	12:02:00	0:56:00	1	9
September 26, 2008	8:50	11:10:00	2:20:00	2	9
October 16, 2008	7:20:00 PM	9:10:00 PM	1:50:00	20	9
June 27, 2008	4:26	8:36:00	4:10:00	5	9
August 5, 2008	13:00	14:30:00	1:30:00	1	9
October 31, 2008	8:32	10:41:00	2:09:00	1	9

INTERROGATORY # 19 – Financial Statements

CNPI – Port Colborne specific interrogatories

Ref: Exhibit 1/Tab 3/Schedule 2 – 2007 Audited Financial Statements and Pro forma financial statements for 2008 and 2009

In Exhibit 1/Tab 3/Schedule 2, CNPI documents a net loss after taxes for the Port Colborne service area of $75,074 in 2007, $82,631 forecasted in 2008 and $217,839 forecasted in 2009. In Note 16 of CNPI's Audited Financial Statements, CNPI shows a net loss after taxes of $168K in 2007 for the Port Colborne service area, following net earnings of $245K in 2006.

a) Please reconcile the 2007 actual results between Note 16 of the 2007 Audited Financial Statements.
b) Please provide further explanation for the actual and forecasted net losses in the Post Colborne service area from 2007 to 2009 forecasted.

RESPONSE:

a) Please refer to Exhibit 1/Tab 3/Schedule 1 Appendix B page 1. This Schedule reconciles the 2007 Audited results to the 2007 RRR and to the 2007 Pro Forma Statements.

b) The 2006 EDR was based on 2004 actuals. In the two year period, capital improvements to the distribution system were made that increased interest and amortization expenses that were not reflected in rates. In the pro forma financial statements, the operating costs from 2007 to 2009 are relatively flat except for amortization and interest expenses. Port Colborne has actual and forecasted losses because of the growth in the rate base with no rebasing of distribution rates.

INTERROGATORY # 20 - Weather Normalization and Modelling

Interrogatories common to all three applications

Ref: Exhibit 3/Tab 2/Schedule 1

CNPI references the Cost Allocation Informational Filing for which Hydro One determined the weather-normalized data that was subsequently used for the current applications. CNPI explains how the Province-wide IESO historical weather correction factors were used as the basis for weather-normalizing the Applicant's 2005 to 2007 data.

Please:

a) Provide the Hydro One report and any spreadsheets containing data supporting the calculation of the weather-normalized historical load,
b) Rationalize how the IESO data which averages the weather-load data from throughout the *whole* Province, is a sufficiently accurate weather-load basis for the Applicant's three geographically-diverse service areas (and required only to be modified for weather-sensitive and non-weather-sensitive loads) to make them applicable for each respective service area.

RESPONSE:

a) Three WINZIP files are accompanying these responses with the Hydro One spreadsheets containing data supporting the calculation of the weather-normalized historical load. The files are:
   - Hydro One Load Shape details for Fort Erie
   - Hydro One Load Shape details for Port Colborne
   - Hydro One Load Shape details for EOP

b) For all electricity distribution companies, throughput and demand will be changing constantly in response to a number of external factors including customer additions and deletions, weather conditions, customer behaviour and industrial commercial activity and economic indicators. The IESO, in its role as manager of Ontario's electricity market, is an authority as it relates to electricity consumption in the province. It is CNPI's belief, from reviewing the Ontario 18-Month Demand Forecast that the IESO considers many variables when assessing the impact of weather upon electricity consumption; data that may not be available at the local level for LDCs.

These variables include but are not limited to provincial economic indicators, coincidence weather data with on peak and off peak loads, correlation of prolonged weather patterns and consumption and industrial and commercial activity.

It is CNPI's assertion that for smaller LDCs, like CNPI's operating territories, with operations confined to a small geographic and demographic footprint, there is a lack of available data to construct a valid weather normalization algorithm. In its discussions with The Weather Network Commercial Services, there is insufficient data available at the localized level, like Fort Erie, Port Colborne or Gananoque, to construct an estimation of weather impact. Other than minimum and maximum air temperature little other data was available. For example there is no data on wind speed, cloud cover and humidity, etc. There is insufficient economic statistics maintained at the municipal level that could provide a comprehensive data set for the service territory.

A smaller LDC with limited diversity in its customer base will recognize volatility in its throughput arising from both localized economic impacts such as the loss of major customers in Port Colborne and Gananoque, or the impact on cross border traffic resulting from the relative value of the Canadian and American currency that would have to factored into a normalization algorithm. The provincial perspective of the IESO also recognizes these economic indicators and their impacts on an aggregate basis.

On this basis, CNPI suggests that the IESO 18-Month Demand Forecast is a proven and accepted barometer of the impact of weather on electricity consumption in the province and in the absence of a proven localized solution is among the most acceptable means available to put forth a rational forecast.

The IESO has the expertise, data, and means to produce an accurate normalized data set.

Recognizing that the IESO normalized data is for the entire load, CNPI has prorated the calculated annual adjustment on the basis of CNPI's ratio of weather and non-weather loads. This has been done on a service territory specific basis using the data set provided by Hydro One as part of the 2006 Cost Allocation Informational Filing.

INTERROGATORY # 21 - Weather Normalization and Modelling

Interrogatories common to all three applications

Ref: Exhibit 3/Tab 2/Schedule 1/ and Appendix A

In Schedule 1 CNPI states: "To further support the reasonableness of the weather normalization factor derived …" additional data were derived; specifically, the number of Heating and Cooling Degree Days were determined based on a 30 Year Average and for 2005, 2006 and 2007. Appendix A shows the GWh Weather Correction values for each week for the May 2002 to May 2008 period. It is not obvious how (a) the additional data support the reasonableness of the factors determined, (b) how the number of Heating and Cooling Degree Days were determined to ascertain the 30 Year Average, or (c) the role played, if any, by the 2002-2004 data in Appendix A.

Please:
a) Explain how, with reference to the values calculated for each service area in turn, the reasonableness of the weather normalization factor is supported by the additional data derived,
b) Explain how, with reference to the values calculated for each service area in turn, the Applicant's forecast would change if, instead of basing the forecast on the average weather over a 30 year period, the Applicant had based it on:
   (i) 10 year average weather, or
   (ii) 20 year trend in weather,
c) Explain how the number of Heating and Cooling Degree Days were ascertained to determine the 30 Year Average and the values for 2005, 2006 and 2007, and
d) Explain the role played by the 2002-2004 data in Appendix A.

RESPONSE:

a) CNPI has included this information only to illustrate the correlation that exists between the total mean degree days recorded for the year and the normalizing adjustment factors to develop the normalized throughput of that same year.

b) Using the average weather over 30 years, 10 years or 20 year average weather forecast would not have an impact on CNPI's forecast. As explained in a) above, the reference to weather normals was merely use to illustrate that the weather adjustment factors stemming from the use of the IESO 18-Month Demand Outlook correlate with the total degree days determined from the data obtained by CNPI from The Weather Network Commercial Services.

c) CNPI acquired the 30 year average temperature data from The Weather Network Commercial Services along with data for 2005, 2006 and 2007.

If the mean temperature for a given day is in excess of 18 degrees Celsius, the heating degree day value is equal to the temperature for that day minus 18. For example, if the temperature was 23 then it would correspond to 5 heating degree days. Correspondingly, it the temperature on that day was 5 degrees Celsius, the cooling degree day would be 13.

Using the data acquired, the heating and cooling degree days were calculated for the thirty year average, 2005, 2006 and 2007.

d) In Appendix A, the IESO 18-Month Demand Outlook data is taken from the IESO public website. Specifically Table 2.2 Actual and Weather Corrected Weekly Energy Demand is shown from May 2002. The 2002 to 2004 was shown for completeness of the data. CNPI did not modify the original table in any manner other than to aggregate data for the years 2005, 2006 and 2007.

INTERROGATORY # 22 - Expected Future Change

Interrogatories common to all three applications

Ref: Exhibit 3/Tab 2/Schedule 1

CNPI explains that it has "…taken a microeconomic view in determining its customer and load forecast through to 2009. Being a smaller LDC, its customer forecasts for growth and energy throughput are more influenced by the microeconomic and socioeconomic conditions within the community, rather than larger scale macroeconomics and the use of econometric equations." It goes on to explain that in many cases the annual *average* use per customer per year (normalized in many customer classes) is the constant value that is extrapolated for establishing future values.

Please:

a) Explain how CNPI's forecasting methodology is differentiated from an approach that would rely solely (or substantially) on a 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
b) 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:

a) CNPI's forecast is differentiated from an approach that would rely solely (or substantially) on a simple extrapolation of the past and which would ignore both broader economic effects that would impact the Province as a whole, because it looks at the discrete events that influence the local forecast. In its forecast, CNPI has attempted to factor the impacts of local industrial, commercial and residential indicators. These indicators have a significant impact on future values.

For example, in Port Colborne CNPI has analyzed, what was described in the Application as atypical General Service 50 to 4,999 kW customers. Following such analysis it divided the customers into sub groups to allow a more comprehensive forecasting and understanding of the customers in that class.

An examination of the utilization of boat services and the anticipated load characteristics of the embedded generation customers was necessary at a micro level to fully understand and forecast the class.

Another example is the loss of industrial customers in Port Colborne and Gananoque. For a smaller LDC, these discrete events have to be understood and forecasted individually to produce a valid forecast. In a smaller LDC with limited customer diversity, it is unlikely that a simple extrapolation of the past will provide a valid forecast.

With the Residential and General Service less than 50 kW, customer volumes and diversity do permit a more generalized extrapolation to forecast future values. However, in this instance it is still necessary to understand the local LDC community, the economic pressures it is experiencing and be able to use this information to help guide the forecast.

With respect to energy consumption associated with provincial CDM initiatives, the forecast based on normalized historic metrics would have taken into account the most recent customer behavioural changes stemming from conservation initiatives. Maintaining per customer consumption at existing levels reflects these reductions in the forecast.

b) To help address this interrogatory, CNPI has referenced the *Provincial Outlook Autumn 2008: Economic Forecast,* prepared by the Conference Board of Canada.

In the Applications, CNPI projected modest growth and as described in the response to part a), factored known events into such projections. The communities served by CNPI, especially Gananoque and Port Colborne, were, already in the first quarter of 2008, experiencing losses in the industrial sector. CNPI in its forecasting recognized these events and forecasted accordingly.

In the *Provincial Outlook Autumn 2008: Economic Forecast* in particular its discussion of Ontario on page 26, wrote, “In the early half of 2008, a robust domestic economy counterbalanced a tenuous trade outlook. Low financing rate and favourable wage settlement agreements fuelled consumption of automotive products and household semi-durables.” During the preparation of its electricity distribution rate applications, in the communities serviced by CNPI, CNPI had already began to experience a much less robust economy than that described above and had tempered its forecasting accordingly.

Later in *Provincial Outlook Autumn 2008: Economic Forecast,* on that same page it goes on to say, “However, the aftermath of the global financial crisis has spread beyond financial markets. By the final quarter of 2008, the effects of the crisis had begun to permeate Ontario’s “real” economy in the form of job losses, slower household consumer demand, and weak investment activity.”

The economic recession referred to in the latter reference had begun to be experienced by communities served by CNPI, especially Gananoque, at the time CNPI was preparing forecasts for the Applications. For these reasons, CNPI chose not to forecast using broader economic indicators but rather to concentrate on what was happening locally.

INTERROGATORY # 23 - kW and Revenue Forecast

Interrogatories common to all three applications

Ref: Exhibit 3/Tab 2/Schedule 1

CNPI discusses the role played by the class load factors in its kWh to kW conversion process and provides a definition of the factors. The numerical value of the class load factors is not shown nor is the derivation of the values.

Please provide full details of the development of the kWh to kW conversion factors including the process and values used to develop the factors for each of the customer classes.

RESPONSE:

This process is used only to develop normalized kW for the General Service 50 to 4,999 kW class; the Street Lighting and Sentinel class, also billed on kW, are not weather sensitive.

The methodology is employed in the Customer and Load Forecast Model. For illustration purposes this response refers to the CNPI – Fort Erie Customer and Load Forecast Model, CNPI_CustomerandLoad_Forecast.xls. The actual recorded kW for the General Service 50 to 4,999 kW for 2007 is provided on Tab [Fort Erie Forecast] Cell H28 (383,911 kW). On the same worksheet, Tab [FE Normalization] provides the details of the conversion process described in Exhibit 3/Tab 2/Schedule 1. On Tab [FE Normalization] Cells F24 (14,072,764 kWh) and F27 (383,911 kW) contain the actual recorded sales data for the General Service 50 to 4,999 kW brought forward from the Tab [Fort Erie Forecast]. Cell F26 (141,700,013 kWh) contains the normalized kWh and was developed using the weather normalization methodology explained in the Application and in other interrogatories. In row 27 the recorded kW sales in Cell F27 has been split into the weather sensitive, D27 (135,521 kW), and non-weather sensitive, E27 (248,390 kW), using the percentage determined by Hydro One Networks in the Cost Allocation Informational Filing process. For CNPI – Fort Erie, Hydro One Networks had determined that 35.3% of the General Service 50 to 4,999 kW class load was weather sensitive.

Cell 28 (51%) is the average class load factor calculated using the methodology under review in this interrogatory. The General Service 50 to 4,999 kW class load factor is determined by dividing the recorded annual kWh in Cell D24 by the product of recorded annual kW in Cell D27, the average number of days in a billing period (365/12), and the number of hours in a day (24). In this particular case;

$$\text{Load Factor} = \frac{50{,}151{,}686\text{ kWh}}{(135{,}521\text{ kW} * 365/12 * 24\text{hours})} = 51\%$$

By reversing the equation and using the weather adjusted kWh, the weather sensitive kW can be determined. This is calculated in Cell D29 (134,513 kW) by dividing the weather sensitive kWh in Cell D26 (49,778,934 kWh) by the product of the load factor calculated in Cell D28 (51%), the average number of days in a billing period (365/12) and the number of hours in a day (24).

$$\text{Normalized kW} = \frac{49{,}778{,}934\text{ kWh}}{(51\% * 365/12 * 24\text{hours})} = 134{,}513\text{ kW}$$

Note that any discrepancy between the spreadsheet and this illustration is due to rounding.

This is the only application for the methodology discussed in Exhibit 3/Tab 2/Schedule 1 page 5. It provides a means of adjusting the billing demand to reflect the weather normalized throughput.

INTERROGATORY # 24 - Load and Revenue Forecast

Interrogatories common to all three applications

Ref: Exhibit 3

In Exhibit 3, CNPI has developed its load and revenue forecasts. While there is no precise method to measure the accuracy of this forecast until after the actual load has been met, the applicant's forecasting track record based on historical forecasts or backcasting statistics based on the current forecast, may provide some indication of the accuracy of the current forecast.

Please provide any data CNPI has that may indicate the accuracy of its current or previous load forecasts.

RESPONSE:

CNPI does not normally produce an annual customer and load forecast. Because actual customer and load growth has been very modest in the past, financial and business forecasting has been produced using generalized assumptions regarding throughput and distribution rates. Throughput growth has normally been forecasted in a range of 0.25% to 0.5% per annum and rates forecasted using assumptions drawn from the Incentive Rate Mechanism process.

In the CNPI distribution operating territories, actual growth (or decline) has been more a function of the local economic environment. For example the plant closures and cutbacks in all three territories have influenced the actual customer counts and throughput realized. The downturn in the industrial base in Gananoque, the loss of a major industry in Port Colborne, the utilization of boat services in Port Colborne and down sizing of some industries in Fort Erie are all examples of discreet metrics that will have a profound impact on forecasting.

CNPI will normally factor these known and/or predicted events into its business planning while using the modest throughput growth metrics discussed in the first paragraph. CNPI is unable to provide any form of backcasting that could aid the Board in assessing the accuracy of its forecast used in the Applications.

INTERROGATORY # 25 - Weather Normalization and Modelling

CNPI – EOP specific interrogatories

Ref: Exhibit 3/Tab 2/Schedule 1/ pages 4-5

On page 4, CNPI shows the Weather Correction Factors it developed for the years 2005, 2006 and 2007 to be respectively a 2.24% correction for a more-than-average electrically-demanding year, a 1.14% correction for a less-than-average electrically-demanding year, and a 0.79% correction for a more-than-average electrically-demanding year. On page 5, in the un-numbered table, CNPI shows the number of Heating and Cooling Degree Days determined for a 30 Year Average and for 2005, 2006 and 2007.

Please:

a) Confirm that the 2005, 2006 and 2007 Total Mean Degree Days in the un-numbered table on page 5, show that based on Total Mean Degree Days these years were approximately 2.84% more-than-average electrically demanding, 10.36% less-than-average electrically demanding, and 5.98% more-than-average electrically demanding compared to the 30 Year Average (value 4,282.1),
b) Explain the differences in magnitude (from an average electrically-demanding year) between the data values in pages 4 and 5; specifically:

Year	Page 4 data indicates the year was more/less electrically demanding	Page 5 data indicates the year was more/less electrically demanding
2005	2.24% more	2.84% more
2006	1.14% less	10.36% less
2007	0.79% more	5.98% more

RESPONSE:

a) CNPI – Eastern Ontario Power can confirm that in the un-numbered table on page 5, the Total Mean Degree Days in years 2005 through 2007 respectively, when compared to the average were 2.84% more-than-average, 10.36% less-than-average and 5.98% more-than-average mathematically. However, CNPI cannot confirm whether they were more or less electrically demanding than average.

As explained in the response to question #20 of this set of interrogatories, the temperature is only one of many variables that determine if the day is more or less electrically demanding.

Matters such as;

Did this day occur on a weekend of statutory holiday?
Was the day preceded by a cooler day?
Was the warmer period merely an anomaly during spring or fall?
Were the economic conditions at the time one of restraint?
Was there significant cloud cover and rain?

As discussed in the response to question #20, while temperature is an indicator it is not the sole variable that must be considered when developing a weather normalized forecast.

b) The explanation for the variance highlighted in the table shown in the question is likely due to variables discussed above. For many reasons, while there is correlation between the total degree days and the electrical consumption, there are other variables that must be considered. CNPI – Eastern Ontario Power believes that the IESO considers these variables, in its determination of a weather normalized forecast.

INTERROGATORY # 26 - Weather Normalization and Modelling

<u>CNPI – EOP specific interrogatories</u>

Ref: Exhibit 3/Tab 2/Schedule 1/Appendix A, page 4

On page 4, CNPI shows separately for the years 2005, 2006 and 2007, the "IESO Weather Normalization Factor" for the applicable year. For any year, the value of the factor is shown to be the same for the first three classes/sub-classes (i.e. Residential, GS < 50 kW and GS > 50 kW Weather Sensitive) but different for GS > 50 kW T.O.U. Weather Sensitive.

Please:

a) Clarify if the "IESO Weather Normalization Factor" value used for the first three classes/sub-classes is an IESO-provided value or a value calculated by the Applicant based on an IESO-provided value,
b) Explain the rationale for using the Applicant's value for some classes/sub-classes and using the IESO value for another sub-class.

RESPONSE:

a) The "IESO Weather Normalization Factor" is a value calculated by the Applicant based on an IESO-provided value. The methodology for determining the value is shown in Exhibit 3/Tab 2/Schedule 1/Appendix A, page 10.

b) It was the Applicant's intent to use its calculated value for all classes/sub-classes. Using the IESO value for the GS > 50 kW T.O.U. Weather Sensitive was an error. During the evolution of the spreadsheet, "CNPI-EOP_CustomerandLoadForecast_20080815.xls', the determination of normalized values on Tab [EOP Normalization] contained hard coded values; this was later revised to reference cells on the Tab [EOP Factors]. The calculations in column G Tab [EOP Normalization] relating to the GS > 50 kW T.O.U. subclass were omitted from the revision.

   CNPI will correct this error, along with any other revisions arising from the interrogatories. The is no impact to the customer forecast because the remaining two customers in the General Service 50 to 4,999 kW Time of Use class have been moved to the General Service 50 to 4,999 kW class for the 2009 forecast and the two have been forecasted discretely because of the significant loss of customers and throughput.

INTERROGATORY # 27- kWh and Revenue Forecast

CNPI – EOP specific interrogatories

Ref: Exhibit 3/Tab 2/Schedule 1/ pages 11-12

On page 11, CNPI explains that by the end of 2008 there will be only two of the six customers remaining in the General Service 50 to 4,999 kW class. While some supporting data are provided, there is not sufficient data to permit an independent assessment of the forecasted load for this key customer class.

Please provide multi-year data separately for each of the two remaining customers together with supporting text that fully explains the forecast shown in the un-numbered table on page 11. To retain confidentiality, it will be sufficient to refer to the customers as “A” and “B”.

RESPONSE:

The chart below provides sales data in kWh and kW for the two customers that remain as General Service 50 to 4,999 kW Time of Use following closure of the fourth customer in September 2008. It is important to note that the 2008 data shown Exhibit 3/Tab 2/Schedule 1 includes data for the last of the four customers to cease operation.

Consumption Data for Two Customers Remaining as GS > 50 kW TOU

	2006				2007				2008 (1)			
	Customer "A"		Customer "B"		Customer "A"		Customer "B"		Customer "A"		Customer "B"	
Month	**kW**	**kWh**	**kW**	**kWh**	**kW**	**kWh**	**kW**	**kWh**	**kW**	**kWh**	**kW**	**kWh**
January	324	94,864	526	240,540	506	109,655	530	250,659	333	86,528	552	251,379
February	331	91,140	526	226,876	323	87,247	541	226,267	357	88,255	524	236,044
March	344	95,335	571	260,521	341	88,368	551	245,526	352	91,326	548	244,439
April	311	70,678	594	232,806	322	105,780	588	237,163	341	81,653	629	267,554
May	309	85,542	680	265,349	335	117,471	643	279,179	334	73,154	613	264,278
June	312	94,887	642	288,072	348	87,967	704	297,103	324	97,871	667	287,610
July	315	78,156	672	288,391	344	66,108	704	311,091	343	88,136	680	302,651
August	311	113,746	688	302,365	365	120,002	703	309,124	320	80,795	666	274,876
September	292	97,760	638	268,408	330	94,228	686	271,813	347	64,492	671	270,007
October	306	122,146	611	258,336	339	122,928	657	274,474	362	72,792	599	253,996
November	298	122,461	583	260,690	343	112,003	560	240,558				
December	302	92,673	535	208,913	359	74,026	530	204,608				
Total	3,755	1,159,388	7,266	3,101,267	4,255	1,185,783	7,397	3,147,565	4,096	990,002	7,379	3,183,401
Monthly Avg	313	96,616	606	258,439	355	98,815	616	262,297	341	99,000	615	265,283

(1) 2008 has been prorated to 12 months for Total and Monthly Average

The 2008 data is actual billing data to the end of October; the totals have been prorated by a factor of 12/10 to estimate 12 months data.

In preparation of the forecast data used in the Application only five months of actual data were available for 2008. These five months were extrapolated to estimate the 2008 usage per customer and then the 2009 projections.

Historical & Forecst Values

	2006	2007	2008	2009 (1)
kWh	4,260,655	4,333,348	4,173,403	4,067,427
kWh per Customer	2,130,328	2,166,674	2,086,702	2,033,714
kW	11,021	11,652	11,474	11,049
kW per Customer	5,511	5,826	5,737	5,525

(1) Forecast values used in the Application

Above is the annual and per customer values for the two customers. The 2009 values are those used in the Application.

INTERROGATORY # 28 - kWh and Revenue Forecast

<u>CNPI – EOP specific interrogatories</u>

Ref: Exhibit 3/Tab 1/Schedule 2/ page 1 and Exhibit 3/Tab 2/Schedule 1/page 16

In the first un-numbered table in Exhibit 3/Tab 1/Schedule 2/page 1, CNPI provides a summary of its 2009 kWh forecasted load. In the un-numbered table in Exhibit 3/Tab 2/Schedule 1/page 16, it provides a summary of its 2009 kWh and kW forecasted load. The kWh values in the two referenced tables do not agree. Also, the kWh and kW values in the second referenced table do not appear to be the respective sums of the individual customer classes values detailed in the pages preceding page 16.

Please provide a table showing the class-by-class values and totals (for Number of Connections, kWh load and kW load) for the Applicant's historical periods, its 2008 forecast and its 2009 forecast.

RESPONSE:

The origin of this discrepancy between the tables is in the rate design model for CNPI – Eastern Ontario Power. The 2009 volumes for kW and kWh for the respective customer classes and subclasses used to calculate distribution rates were incorrectly calculated as the average of the 2008 and 2009 forecasted volumes. CNPI discovered the error while responding to these and other interrogatories.

Interrogatories from the Vulnerable Energy Consumers Coalition revealed the same discrepancy.

This will be corrected in a revised rate design model and new tables generated.

INTERROGATORY # 29 - Customer Count, kWh load, kW load and Revenue

CNPI – EOP specific interrogatories

Ref: Exhibit 3

Some of CNPI'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:

In light of issues raised in these and other interrogatories, CNPI – Eastern Ontario Power will be re-filing portions of its 2009 Electricity Distribution Rate Application. These issues include the following:

- Correction of the kW and kWh volumes used to calculate distribution rates. CNPI – Eastern Ontario Power had in advertently taken the average of 2008 and 2009 volumes as its determinant for rate design.
- Correction of the General Service 50 to 4,999 kW TOU weather normalization as determined by OEB Board Staff interrogatory # 26.

For purposes of these interrogatories, CNPI – Eastern Ontario Power will re-file its Rate Design Model, including the electronic version, with the revisions highlighted.

INTERROGATORY # 30 - Weather Normalization and Modelling

CNPI – Fort Erie specific interrogatories

Ref: Exhibit 3/ Tab 2/ Schedule 1/ pages 4-5

On page 4, CNPI shows the Weather Correction Factors it developed for the years 2005, 2006 and 2007 to be respectively a 2.10% correction for a more-than-average electrically-demanding year, a 1.07% correction for a less-than-average electrically-demanding year, and a 0.74% correction for a more-than-average electrically-demanding year. On page 4, in the second un-numbered table, the Applicant also shows the number of Heating and Cooling Degree Days determined for a 30 Year Average and for 2005, 2006 and 2007.

Please:

a) Confirm that the 2005, 2006 and 2007 Total Mean Degree Days in the second un-numbered table on page 4, show that based on Total Mean Degree Days these years were approximately 4.33% more-than-average electrically demanding, 9.83% less-than-average electrically demanding, and 0.94% less-than-average electrically demanding compared to the 30 Year Average (value 4,282.1),
b) Explain the differences in sign and in magnitude (from an average-electrically demanding year) between the data values in pages 4 and 5; specifically:

Year	Page 4 data indicates the year was more/less electrically demanding	Page 5 data indicates the year was more/less electrically demanding
2005	2.10% more	4.33% more
2006	1.07% less	9.83% less
2007	0.74% *more*	0.94% *less*

RESPONSE:

a) CNPI – Fort Erie can confirm that in the un-numbered table on page 5, that the Total Mean Degree Days in years 2005 through 2007 respectively, when compared to the average, were 4.33% more-than-average, 9.83% less-than-average and 0.94% more-than-average mathematically. However, CNPI cannot confirm whether they were more or less electrically demanding than average.

As explained in the response to question #20 of this set of interrogatories, the temperature is only one of many variables that determine if the day is more or less electrically demanding.

Matters such as;

Did this day occur on a weekend of statutory holiday?

Was the day preceded by a cooler day?

Was the warmer period merely an anomaly during spring or fall?

Were the economic conditions at the time one of restraint?

Was there significant cloud cover and rain?

As discussed in the response to question #20, while temperature is an indicator it is not the sole variable that must be considered when developing a weather normalized forecast.

b) The explanation for the variance highlighted in the table shown in the question is likely due to variables discussed above. For many reasons, while there is correlation between the total degree days and the electrical consumption, there are other variables that must be considered. CNPI – Fort Erie believes that the IESO considers these variables in its determination of a weather normalized forecast.

INTERROGATORY # 31 - kWh and Revenue Forecast

CNPI – Fort Erie specific interrogatories

Ref: Exhibit 3/Tab 1/Schedule 2/page 1 and Exhibit 3/Tab 2/Schedule 1/page 14

In the first un-numbered table in Exhibit 3/Tab 1/Schedule 2/page 1, CNPI provides a summary of its 2009 kWh forecasted load. In the un-numbered table in Exhibit 3/Tab 2/Schedule 1/page 14, it provides another kWh summary. While the total kWh values in the two tables agree, some kWh values in the first referenced table do not appear to agree with the values detailed in the subsequent pages thus resulting in a different total from that shown in both tables.

Please provide a table showing the class-by-class values and totals (for Number of Connections, kWh load and kW load) for the Applicant's historical periods, its 2008 forecast and its 2009 forecast.

RESPONSE:

The origin of this discrepancy between the tables is in the rate design model for CNPI – Fort Erie. The 2009 volumes for kW and kWh for the respective customer classes and subclasses used to calculate distribution rates were incorrectly calculated as the average of the 2008 and 2009 forecasted volumes. CNPI discovered the error while responding to these and other interrogatories.

Interrogatories from the Vulnerable Energy Consumers Coalition revealed the same discrepancy.

This will be corrected in a revised rate design model and new tables generated.

INTERROGATORY # 32 – Other Revenue

CNPI – Fort Erie specific interrogatories

Ref: Exhibit 3/Tab 3/Schedule 1/pages 1-2

On page 1, CNPI shows a significant reduction from historical levels in the forecasted Interest and Dividend Income.

Please provide supporting data.

RESPONSE:

The interest and dividend income account consists of interest on bank accounts. The reduction from historical levels is a result of reductions and fluctuations in cash balances in the bank accounts. Please refer to the balance sheet in the pro forma financial statements (Exhibit 1/Tab 3/Schedule 2), the cash balance at December 31 in 2007 is $7.3M dropping to $1.3M in 2008 and $3.6M in 2009.

INTERROGATORY # 33 - Customer Count, kWh load, kW load and Revenue

CNPI – Fort Erie specific interrogatories

Ref: Exhibit 3

Some of CNPI'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:

In light of issues raised in these and other interrogatories, CNPI – Fort Erie will be re-filing portions of its 2009 Electricity Distribution Rate Application. These issues include the following:

- Correction of the kW and kWh volumes used to calculate distribution rates. CNPI – Fort Erie had inadvertently taken the average of 2008 and 2009 volumes as its determinant for rate design.

For purposes of these interrogatories, CNPI – Fort Erie will re-file its Rate Design Model, including the electronic version, with the revisions highlighted.

INTERROGATORY # 34 - Weather Normalization and Modelling

CNPI – Port Colborne specific interrogatories

Ref: Exhibit 3/Tab 2/Schedule 1/ pages 4-5

On page 4, CNPI shows the Weather Correction Factors it developed for the years 2005, 2006 and 2007 to be respectively a 2.15% correction for a more-than-average electrically-demanding year, a 1.09% correction for a less-than-average electrically-demanding year, and a 0.76% correction for a more-than-average electrically-demanding year. On page 5, in the un-numbered table, the Applicant shows the number of Heating and Cooling Degree Days determined for a 30 Year Average and for 2005, 2006 and 2007.

Please:

a) Confirm that the 2005, 2006 and 2007 Total Mean Degree Days in the un-numbered table on page 5, show that based on Total Mean Degree Days these years were approximately 6.75% more-than-average electrically demanding, 9.35% less-than-average electrically demanding, and 0.25% more-than-average electrically demanding compared to the 30 Year Average (value 3,861.4),

b) Explain the differences in magnitude (from an average electrically-demanding year) between the data values in pages 4 and 5; specifically:

Year	Page 4 data indicates the year was more/less electrically demanding	Page 5 data indicates the year was more/less electrically demanding
2005	2.15% more	6.75% more
2006	1.09% less	9.35% less
2007	0.76% more	0.25% more

RESPONSE:

a) CNPI – Port Colborne can confirm that in the un-numbered table on page 5, that the Total Mean Degree Days in the years 2005 through 2007 respectively were, when compared to the average, 6.75% more-than-average (2005), 9.35% less-than-average (2006) and 0.25% more-than-average (2007) mathematically. However, CNPI cannot confirm if they were more or less electrically demanding than average.

As explained in the response to question #20 of this set of interrogatories, the temperature is only one of many variables that determine if the day is more or less electrically demanding.

Matters such as;

Did this day occur on a weekend of statutory holiday?
Was the day preceded by a cooler day?
Was the warmer period merely an anomaly during spring or fall?
Were the economic conditions at the time one of restraint?
Was there significant cloud cover and rain?

As discussed in the response to question #20, while temperature is an indicator it is not the sole variable that must be considered when developing a weather normalized forecast.

b) The explanation for the variance highlighted in the table shown in the question is likely due to variables discussed above. For many reasons, while there is correlation between the total degree days and the electrical consumption, there are other variables that must be considered. CNPI – Port Colborne believes that the IESO considers these variables in its determination of a weather normalized forecast.

INTERROGATORY # 35 - kWh and Revenue Forecast

CNPI – Port Colborne specific interrogatories

Ref: Exhibit 3/Tab 2/Schedule 1/pages 8-10 and Appendix A, page 2

On page 8, CNPI explains regarding the Residential class and on page 9 regarding the General Service < 50 kW class, that it has assumed the forecasted growth to be the average of the annual growth in the previous three years (2005-2007). In Appendix A, page 2, the Applicant provides historical growth for the previous six years (2002-2007). The historical growth over the shorter period (2005-2007) would appear to be moderately lower for both the Number of Customers and kWh load compared to the longer historical period (2002-2007), thus resulting in higher rates.
Please:

a) Explain why CNPI has chosen to base its forecast on the shorter historical period, and
b) Estimate the resulting Number of Customers and kWh load if the forecasts were based on the longer historical period.

RESPONSE:

a) CNPI has chosen to base its customer forecast on the shorter historical period to better reflect the current economic climate in Port Colborne. There have only been 67 new residential services from 2004 to 2007; with only 33 of these in the past two years, 2006 and 2007. With the exception of 2004, growth has been minimal. These actual statistics combined with the recent closures of a large industry in Port Colborne (discussed in Exhibit 3, Tab 2, Schedule 1, page 16), the earlier closure of an oil storage facility in 2007 and the announced closure of a nearby John Deere plant all indicate continued minimal growth. These closures coupled with no known significant economic growth indicate a trend similar to that seen in the past few years. The use of the longer historical period would minimize the current circumstances and would therefore result in CNPI – Port Colborne experiencing a revenue deficiency.

   For these reasons, CNPI has used only the period of 2005 to 2007 as an indicator of growth in the test year.

b) Had CNPI used the longer historical period residential growth in the bridge year and test year would have been 0.62% as opposed to the forecasted value of 0.28%. For the General Service < 50 kW, growth in 2009 would have been 0.44% as opposed to the forecasted amount of 0.21%.

An estimate of the resulting number of Customers and kWh load if the forecasts were based on the longer historical period is shown in the table below.

Revised to Respond to OEB Interrogatory # 35

CNPI - Port Colborne Load and Customer Forecast Information

	Data From 2006 EDR Board Approved Model				From Energy Sales			Projected	
	2002	2003	2004	2006 EDR	2005 Year End	2006 Year End	2007 Year End	2008 Bridge Year	2009
Residential									
Number of Customers	7,885	7,943	8,064	8,064	8,098	8,115	8,131	8,160	8,211
Percent Change in Customers		0.74%	1.52%		0.42%	0.21%	0.20%	0.62%	0.62%
Recorded Kilowatt-hours Sold	55,948,133	67,222,437	61,303,778	62,256,160	65,834,052	63,377,413	65,276,604		
Recorded Avg Use per Customer	7,096	8,463	7,602	7,720	8,130	7,810	8,028		
Normalized Kilowatt-hours Sold					64,421,796	64,068,976	64,781,193	65,013,925	65,415,406
Normalized Avg Use per Customer					7,955	7,895	7,967	7,967	7,967
GS < 50 kW									
Number of Customers	911	921	962	962	968	937	930	934	938
Percent Change in Customers		1.10%	4.45%		0.62%	-3.20%	-0.75%	0.44%	0.44%
Recorded Kilowatt-hours Sold	24,146,580	28,166,788	27,297,710	27,405,586	27,395,952	26,343,975	25,917,221		
Recorded Avg Use per Customer	26,506	30,583	28,376	28,488	28,302	28,115	27,868		
Normalized Kilowatt-hours Sold					26,808,261	26,631,436	25,720,525	25,834,906	25,949,795
Normalized Avg Use per Customer					27,694	28,422	27,656	27,656	27,656

Residential year end 2008 reduced by the 21 transfer customers

INTERROGATORY # 36 - kWh and Revenue Forecast

CNPI – Port Colborne specific interrogatories

Ref: Exhibit 3/Tab 2/Schedule 1/page 8

On page 8, CNPI discusses its plan to eliminate long term load transfer arrangements and its December 20, 2007 (EB-2007-0005) filing with the Board.

Please clarify if the adjustments made in the current application are consistent with those proposed in the December 20, 2007 filing and/or consistent with any subsequent Board findings.

RESPONSE:

Yes, the projections of customer counts and volumes in this Application are consistent with those proposed in the December 20, 2007 filing.

INTERROGATORY # 37 - kWh and Revenue Forecast

CNPI – Port Colborne specific interrogatories

Ref: Exhibit 3/Tab 2/Schedule 1/pages 11-19

On pages 11-19, CNPI discusses the development of its load forecast for the General Service 50 to 4,999 kW class. While a number of details are provided, it is not possible to make an independent assessment based on the information filed.

Please provide an active Excel spreadsheet with comments demonstrating the development of this forecast; i.e. a spreadsheet showing the formulae that were used for the calculations in the individual cells together with comments showing the rationale.

RESPONSE:

The details of the derivation of the General Service 50 to 4,999 kW class has been provided in the "CNPI-PC_CustomerandLoadForecast_20080815.xls" workbook provided with the Application. Specifically, two tabs of the workbook; TAB [Port Colborne Forecast] and TAB [Port Colborne GS > 50kW Detail].

As requested and for further detail, CNPI – Port Colborne is providing a separate workbook detailing the development of the General Service 50 to 4,999 kW class forecast.

Reference; CNPI-PC_GSGT50ForecastDetails_OEB37_20081212.xls

Explanation

General	This workbook is an extension of the CNPI - Port Colborne Customer and Load Forecast filed with the CNPI - Port Colborne 2009 EDR Application, EB-2008-0224. The purpose of the workbook is to isolate what are referred to in the Application in Exhibit 3, Tab 2, Schedule 1, pages 11 - 19, as atypical customers from the general population of General Service 50 to 4,999 kW customers for forecasting purposes. In general, the sales data in kW and kWh associated with particular

customers were isolated from data for the entire population for the period of 2005 to 2007 inclusive. This yielded a customer and load data for the balance of customers. It was this balance of customers that were forecasted independently and then added back to the population of atypical customers to provide the final forecast.

The following narrative describes the steps in more detail;

Tab	Comments
Embedded Gx	The embedded Gx Tab provides the combined load data for the two customers in CNPI - Port Colborne with load displacement generation behind their meter. Customer data for these two customers is captured and recorded in the general population of the General Service 50 to 4,999 kW class. These customers are unique in their load mix and are forecasted independently. The forecast for 2008 and 2009 for these two customers was developed following discussions with the customers. Both customers had been increasing their dependency on electricity in order to manage operating costs. 2008 had been forecasted as a straight line extrapolation of the year to date information and 2009 had been forecasted to be similar to 2008.
Embedded Dx	The embedded Dx Tab is the load data associated with an embedded distribution customer, Hydro One Networks, connected to the CNPI - Port Colborne distribution system. 2007 load data was used as the basis for the forecast for 2008 and 2009. Discussion with Hydro One Networks' staff did not yield any forecast data particular to this group of customers. It was generally agreed that any localized growth would be offset by conservation efforts.
Work Interruption	The Work Interruption Tab provides the load information related to a customer that had been subject to a work interruption and eventual closure during preparation of the Customer and Load Forecast for CNPI - Port Colborne. This customer had been one of the larger customers in the class and heavily influenced the class load data. To properly factor in the effects of this customer, its load data was isolated from the data for the general population of customers in the class for the period of 2005 to 2007 inclusive. The plant is currently in lay up mode and is expected to remain that way for the forecast period. CNPI - Port Colborne has forecasted

2008 as an extrapolation of the year to date consumption and has used this same data for 2009.

Boats

The Boats Tab, summarizes the customer and load data associated with Boat Services, supplied as General Service 50 to 4,999 kW, for the period of 2005 to 2007 inclusive.

Utilization of the Boat services is very difficult to predict. It depends on such issues as contract awards from the boat operators and the amount of maintenance work being carried out, if any. For this reason, CNPI - Port Colborne has used the average values for the two most recent years, 2006 and 2007, as the 2008 and 2009 forecast. It is assumed that all eight services will be utilized. The quantities associated with 2005 were lower than more recent years and its inclusion would lower the forecasted quantities.

Summary

The Summary Tab is the summary of all information discussed above. The total class customer and load data for the period of 2002 to 2007 inclusive has been entered here on lines 44 and 45.

For the period of 2005 to 2007, the loads associated with each of the particular groups of customers discussed above were subtracted from the total for the class. This resulted in a sub population of customers that are referred to as typical and are label on the Tab as "Balance of Customers in the Class".

It is these "typical" customers that are in the Balance of Customers category that CNPI - Port Colborne has forecasted collectively for 2008 and 2009. Based on the limited growth that CNPI is seeing, this forecast has been moderately stated at approximately 1.25% per annum.

Once the Balance of Customers grouping had been forecasted the entire population of the General Service 50 to 4,999 kW class was totalled by combing the Balance of Customers grouping with those discussed above to recreate the total customer and load forecast for the class. It is this forecast that is used to develop rates for the General Service 50 to 4,999 kW class.

INTERROGORY # 38 - kWh and Revenue Forecast

CNPI – Port Colborne specific interrogatories

Ref: Exhibit 3/Tab 1/Schedule 2/page 1 and Exhibit 3/Tab 2/Schedule 1/page 22

In the first un-numbered table in Exhibit 3/Tab 1/Schedule 2/page 1, CNPI provides a summary of its 2009 kWh forecasted load. In the un-numbered table in Exhibit 3/Tab 2/Schedule 1/page 22, it provides a summary of its 2009 kWh and kW forecasted load. The kWh values in the two referenced tables do not agree. Also, the kWh value in the second referenced table does not appear to be the sum of the individual customer classes values detailed in the pages preceding page 22.

Please provide a table showing the class-by-class values and totals (for Number of Connections, kWh load and kW load) for the Applicant's historical periods, its 2008 forecast and its 2009 forecast.

RESPONSE:

The origin of this discrepancy between the tables is in the rate design model for CNPI – Port Colborne. The 2009 volumes for kW and kWh for the respective customer classes and subclasses used to calculate distribution rates were incorrectly calculated as the average of the 2008 and 2009 forecasted volumes. CNPI discovered the error while responding these and other interrogatories.

Interrogatories from the Vulnerable Energy Consumers Coalition revealed the same discrepancy.

This will be corrected in a revised rate design model and new tables generated.

INTERROGATORY # 39 - Other Revenue

CNPI – Port Colborne specific interrogatories

Ref: Exhibit 3/Tab 2/Schedule 1/page 21, Exhibit 3/Tab 3/Schedule 1/pages 1-2

In Exhibit 3/Tab 2/Schedule 1/page 21, CNPI discusses Standby/Backup for two customers with load displacement generation facilities and the compensation received for provision of this service. CNPI states it "has allocated standby distribution revenue, if any, to the Base Revenue Requirement…" In Exhibit 3/ Tab 3/Schedule 1/pages 1-2, the Applicant shows how the compensation is allocated to the Miscellaneous Services Revenue account.

Please clarify the Applicant's rationale for allocating *revenue* to *revenue requirement* (i.e. by apparently subtracting *income* from the *cost of operating the utility*) rather than including the standby/backup revenue as part of the utility's total revenue.

RESPONSE:

Below is the excerpt from Exhibit 3/Tab 3/Schedule 1/pages 1-2

Miscellaneous Service Revenues (OEB Account 4235)

Revenues generated from other specific service charges. In 2006, CNPI applied for and received approval from the Board to charge the set of standardized service charges. There are no changes to specific service charges being requested for 2009. Stand-by revenues for two co-generation customers have been allocated to this account up to and including the 2008 Bridge Year. As explained in Schedule 3, these revenues have been removed from the 2009 Test Year.

To clarify this, in the 2006 EDR, CNPI had reported revenue associated with standby distribution revenue for two customers with load displacement generation facilities. At that time in 2006, CNPI's financial recording system was not enabled to account for these revenues as electric revenue. Consequently, CNPI forecasted and reported this revenue as miscellaneous revenue. For rate making purposes the forecasted revenue from standby service was included as miscellaneous revenue and subtracted from the service revenue requirement, therefore the base revenue requirement used to develop distribution rates did not include the revenue associated with standby service.

Below is the excerpt from Exhibit 3/Tab 2/Schedule 1/pages 21/lines 29 to 31

CNPI has allocated standby distribution revenue, if any, to the Base Revenue Requirement for the General Service 50 to 4,999 kW customer class.

To further clarify, for 2009 Test Year, CNPI's financial recording system has the capability to report standby revenue as electric distribution revenue. Therefore, it is no longer necessary to assign forecasted revenue from standby service to miscellaneous revenue and deduct that same forecast from the base revenue requirement.

In this Application, the Miscellaneous Service Revenues (OEB Account 4235) has no association with revenue from standby service. Revenue from standby service, if any, has been forecasted in and will be reported in electric distribution revenue and is part of the base revenue requirement.

INTERROGATORY # 40 - Customer Count, kWh load, kW load and Revenue

CNPI – Port Colborne specific interrogatories

Ref: Exhibit 3

Some of CNPI'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:

In light of issues raised in these and other interrogatories, CNPI – Port Colborne will be re-filing portions of its 2009 Electricity Distribution Rate Application. These issues include the following:

- Correction of the kW and kWh volumes used to calculate distribution rates. CNPI – Port Colborne had inadvertently taken the average of 2008 and 2009 volumes as its determinant for rate design.

For purposes of these interrogatories, CNPI – Port Colborne will re-file its Rate Design Model, including the electronic version, with the revisions highlighted.

INTERROGATORY # 41 - Corporate Cost Allocation

Interrogatories common to all three applications

Ref: Exhibit 4/Tab 3/Schedule 4/Appendix B, and
RP-2005-0020/EB-2005-0344/0345/0346, Exhibit C/Tab 4/Appendix A.

In CNPI's 2006 EDR applications, it proposed a corporate cost allocation study that the Board only accepted for the purposes of the 2006 rates. In its Decision, the Board found that the study had not been sufficiently tested. CNPI has now in the Application for 2009 rates brought forward a corporate cost allocation study to be tested. Comparing the Appendix from the 2006 study to the one filed supporting the 2009 costs of service; there are several differences in departments being allocated. The proposed study appears to not address some of these departments.

a) Please provide a table showing the corporate functions being allocated separately from Fort Erie and Cornwall Electric. In this table list:
   - Function (customer service. financial, etc.)
   - Cost type – (LEM, contractors, etc.)
   - Allocator and rationale
b) When costs are applied to the allocators, how are they applied (simple average, weighted average, specific determination)?
c) For those allocators in b) that are based on historical analysis, would the results differ if they were based on future expectations flowing from corporate plans?

RESPONSE:

a) Attached is the schedule of shared allocations from CNPI-Fort Erie and Cornwall Electric. Please refer to the BDR report "Study of Affiliate Service Costs and Cost Allocation" for detailed discussions of the rationale of all allocations.

b) The derivation of the final cost allocations are based on simple averages as per the schedule. However as discussed in the BDR report each allocator would be derived at by various methods within the particular Function group.

c) The allocators used in the analysis are consistent with future plans and expectations of the corporation. Allocations will be reexamined if such future plans change.

Table of 2009 Corporate Functions Allocated-Shared Services

Function	From Company	To Company	Allocator	Cost	Cost Type	
Finance	CNPI-Fort Erie	CNPI-Fort Erie	20%	170,505	Labour and benefits	796,449
		CNPI-Port Colborne	15%	127,879	Equip., Mat. and training	41,076
		CNPI-EOP	10%	85,252	Consultants	15,000
		CNPI-Transmission	10%	85,252		
		Cornwall Electric	40%	341,010		
		FortisOntario	5%	42,626		
			100%	852,525		852,525
Information Technology	CNPI-Fort Erie	CNPI-Fort Erie	29%	240,862	Labour and benefits	397,825
		CNPI-Port Colborne	17%	141,195	Equip., Mat. and training	117,400
		CNPI-EOP	8%	66,445	Consultants	40,000
		CNPI-Transmission	5%	41,528	Mtce agreements	368,333
		Cornwall Electric	39%	323,918	outside service recoveries	(93,000)
		FortisOntario	2%	16,611		
			100%	830,558		830,558
Human Resources	CNPI-Fort Erie	CNPI-Fort Erie	29%	71,880	Labour and benefits	151,107
		CNPI-Port Colborne	13%	32,222	Equip., Mat. and training	38,756
		CNPI-EOP	10%	24,786	Consultants	9,000
		CNPI-Transmission	5%	12,393	Professional	49,000
		Cornwall Electric	39%	96,666		
		FortisOntario	4%	9,915		
			100%	247,863		247,863
Health and Safety	CNPI-Fort Erie	CNPI-Fort Erie	29%	101,008	Labour and benefits	257,302
		CNPI-Port Colborne	17%	59,212	Equip., Mat. and training	73,002
		CNPI-EOP	8%	27,864	Professional	18,000
		CNPI-Transmission	5%	17,415		
		Cornwall Electric	39%	135,839		
		FortisOntario	2%	6,966		
			100%	348,304		348,304
Regulatory	CNPI-Fort Erie	CNPI-Fort Erie	21%	35,008	Labour and benefits	149,594
		CNPI-Port Colborne	21%	35,008	Equip., Mat. and training	17,110
		CNPI-EOP	21%	35,008		
		CNPI-Transmission	21%	35,008		
		Cornwall Electric	11%	18,337		
		FortisOntario	5%	8,335		
			100%	166,704		166,704
Short Term Incentive	CNPI-Fort Erie	CNPI-Fort Erie	29%	74,385	Labour and benefits	256,500
		CNPI-Port Colborne	17%	43,605		
		CNPI-EOP	8%	20,520		
		CNPI-Transmission	5%	12,825		
		Cornwall Electric	39%	100,035		
		FortisOntario	2%	5,130		
			100%	256,500		
Materials Management	CNPI-Fort Erie	CNPI-Fort Erie	64%	137,680	Labour and benefits	204,553
		CNPI-Port Colborne	24%	51,630	Equip., Mat. and training	10,573
		CNPI-EOP	0%	-		
		CNPI-Transmission	2%	4,303		
		Cornwall Electric	0%	-		
		FortisOntario	10%	21,513		
			100%	215,126		215,126
CNPI Board of Directors	CNPI-Fort Erie	CNPI-Fort Erie	25%	1,500	Professional	6,000
		CNPI-Port Colborne	25%	1,500		
		CNPI-EOP	25%	1,500		
		CNPI-Transmission	25%	1,500		
		Cornwall Electric	0%	-		
		FortisOntario	0%	-		
			100%	6,000		6,000
Property Maintenance	CNPI-Fort Erie	CNPI-Fort Erie	60%	316,025	Labour and benefits	161,924
		CNPI-Port Colborne	30%	158,012	Equip., Mat. and training	132,644
		CNPI-EOP	0%	-	Contractors	117,600
		CNPI-Transmission	10%	52,671	Utilities	114,540
		Cornwall Electric	0%	-		
		FortisOntario	0%	-		
			100%	526,708		526,708
Building Rent	CNPI-Fort Erie	CNPI-Fort Erie	46%	218,647	Rent	475,320
		CNPI-Port Colborne	20%	95,064		
		CNPI-EOP	6%	28,519		
		CNPI-Transmission	7%	33,272		
		Cornwall Electric	18%	85,558		
		FortisOntario	3%	14,260		
			100%	475,320		475,320
***Summary* CNPI Fort Erie**	**CNPI-Fort Erie**	**CNPI-Fort Erie**		**1,367,500**	**Labour and benefits**	**2,375,254**
		CNPI-Port Colborne		**745,327**	**Equip., Mat. and training**	**430,559**
		CNPI-EOP		**289,895**	**Contractors**	**117,600**
		CNPI-Transmission		**296,167**	**Professional**	**73,000**
		Cornwall Electric		**1,101,362**	**Consultants**	**64,000**
		FortisOntario		**125,355**	**Mtce agreements**	**368,333**
					Outside service recoveries	**(93,000)**
					Utilities	**114,540**
					Rent	**475,320**
				3,925,606		**3,925,606**
Materials Management	**Cornwall Electric**	**CNPI-Fort Erie**	**0%**	**-**	**Labour**	**159,678**
		CNPI-Port Colborne	**0%**	**-**	**Equip and Mat**	**16,194**
		CNPI-EOP	**17%**	**29,898**		
		CNPI-Transmission	**0%**	**-**		
		Cornwall Electric	**83%**	**145,974**		
		FortisOntario	**0%**	**-**		
			100%	**175,872**		**175,872**

INTERROGATORY # 42 - Corporate Cost Allocation

Ref: Exhibit 4/Tab 3/Schedule 4/Appendix B, and EB-2005-0001, page 88 (Enbridge Gas)

The Board in its Decision on rates for 2006 for Enbridge Gas listed 5 principles that should be addressed when an independent reviewer assesses corporate cost allocations:

"10.9.28 The Board further finds that in evaluating each service, the independent review should consider whether:
• the service is specifically required by the utility;
• the level of service provided is required by the utility;
• the costs are allocated based on cost causality and cost drivers;
• the cost to provide the service internally would be higher and the cost to acquire the service externally on a standalone basis would be higher; and,
• there are scale economies."

With respect to the BDR Review:
a) Please provide the BDR report on the 5 principles that the Board has stated in its Enbridge Decision if it is available.
b) If BDR did not report on these principles, please comment on them as they apply to the services provided in the corporate cost allocation.

RESPONSE:

The BDR report provided as Exhibit 4/Tab 3/Schedule 4/Appendix B and its 2005 Review, which was filed with the OEB in EB-2005-0344, EB-2005-0345 and EB-2005-0346 are the only reports provided by BDR to the Company on the subject of corporate cost allocations.

The focus of both of these reports is the third of the five principles above, that is, "the costs are allocated based on cost causality and cost drivers". The BDR report documents the nature of each type of cost, identifies the basis of cost causality and cost drivers, and on that basis has provided an opinion that the allocation approach is reasonable and consistent with principles of cost allocation.

The Company's comments on the other four principles are as follows:

1. "the service is specifically required by the utility"

Except for its unregulated generation assets, which now represent a very small component of FortisOntario's operations and costs, FortisOntario's operations are comprised entirely of its four Ontario electricity distribution business units and a transmission business unit, which are regulated by the Board. To maximize available efficiencies of scale, certain general plant and administrative, general and customer service functions are shared by the business units. All of the functions and activities which are shared costs in the case of FortisOntario's operations are the required core functions of electricity distribution and transmission businesses, namely:

- Administrative and general costs, including:
  - executive
  - property and procurement
  - regulatory
  - finance (accounts payable and receivable, payroll, financial analysis and reporting, and supervision of these functions)
  - information technology
  - health, safety and environment
  - human resources management,
  - the Board of Directors of CNPI, and
  - service centre building expenses (rental and maintenance)
- Customer services including billing and collection, call center and on-premises services; and
- Engineering and operations.

The purpose of the allocation process and the filing of its results with the Board is to support the share of the costs of these core functions that should be recovered from each distribution service territory and from transmission through its separate revenue requirement and rates.

2. "the level of service provided is required by the utility"

The level of each service is the level required to meet the requirements of CNPI's distribution customers and of regulation by the Board. There is no duplication through shared services of services or functions that are also provided on a fully dedicated basis within the service territories.

3. "the cost to provide the service internally would be higher"

For historical reasons and because of the Port Colborne lease arrangement, CNPI is continuing to maintain separation of its distribution service territories for rate and regulatory purposes, but has integrated operations and management for all other purposes. Therefore in CNPI's view, the shared services are being provided "internally", in the sense they are provided to all the service territories by an integrated function within CNPI. Only executive management is outside CNPI in FortisOntario. The executive group consists of only five staff, including administrative support. It is our view that ceasing to share the services of this executive team with the other business units of FortisOntario would not enable a reduction in its total size or cost.

CNPI has documented in its evidence the recent measures taken that have reduced staffing levels and costs, and these measures are made possible by the sharing of resources among its business units. CNPI has not specifically studied the cost of duplicating each administrative and general, operations and customer service function for each of the four distribution service territories and its transmission business unit, but would anticipate the result of any such duplication to be cost increases, rather than cost reductions.

4. "and the cost to acquire the service externally on a standalone basis would be higher"

The services shared by CNPI's distribution service territories are all core business functions that are not normally contracted out by Ontario LDCs. With respect to the administrative services such as executive management, information technology, human resources, etc., the Board took this into account in defining the "shared corporate services" that would be excluded from the test for market-based transfer pricing in the Affiliate Relationships Code for Electricity Distributors and Transmitters as revised in May, 2008. The only cost element which would have a specific market comparator would be the allocated cost of space in the Fort Erie head office and service center building, which is priced to each business unit based on the market price for comparable space available for lease.

It is therefore CNPI's position that a comparison of its internal shared costs with the cost to procure from some external source has been made for its building lease costs, and could not reasonably be made for the other services in question.

INTERROGATORY # 43

Ref: Exhibit 4/Tab 2/Schedule 1/Appendix C

CNPI has a vegetation management program that is based on a three-year cycle. In their application before the Board, EB-2007-0681, Hydro One Networks Inc. stated that they were intending to reach an optimum cycle of eight years for their vegetation management program and potentially six years as noted by their consultant's report.

a) Has CNPI assessed their 3 year program relative to other cycle periods?
b) If so, what were the results?
c) If not, would a longer cycle period not provide sufficient vegetation management to protect plant at a lower cost?

RESPONSE:

a) CNPI – Fort Erie has determined with experience that a three-year cycle is a reasonable and appropriate period for vegetation management.

b) and c)

Fort Erie is a heavily treed area with rapid vegetation growth. The vegetation management program aims to maintain adequate clearance between trees and lines while respecting as much as possible the natural environment. A cycle longer than three years would not provide as effective vegetation control, because trees would encroach on lines before scheduled trimming. This could result in outages, affect employee and public safety and increase vegetation management costs. A cycle of less than three years would be inefficient.

INTERROGATORY # 44 – Regulatory Costs

Interrogatories common to all three applications

Ref: Exhibit 4/Tab 2/Schedule 2 p. 5

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 table format shown below.

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 the utility's proposal on how it intends to recover the "One-time" costs as part of its 2009 rate application

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									
2. OEB Hearing Assessments (applicant initiated)									
3. OEB Section 30 Costs (OEB initiated)									
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. Operating expenses associated with other resources allocated to regulatory matters (please identify the resources)									
9. Other regulatory agency fees or assessments									
10. Any other costs for regulatory matters (please define)									

RESPONSE:

a)

CNPI-Fort Erie

Regulatory Cost Category	Ongoing or One-time Cost?	2006 Board Approved	2006 Actual	2007 Actual	% Change in 2007 vs. 2006	2008 Bridge Year	% Change in 2008 vs. 2007	2009 Test Year	% Change in 2009 vs. 2008
1. OEB Annual Assessment	ongoing			46,798	100%	54,300	16%	54,300	0%
2. OEB Hearing Assessments (applicant									
3. OEB Section 30 Costs (OEB initiated)									
4. Expert Witness cost for regulatory matters									
5. Legal costs for regulatory matters	ongoing	14,307	15,633	9,965	-36%	5,500	-45%	8,367	52%
6. Consultants costs for regulatory matters	ongoing		4,747	192	-96%	2,000	942%	13,100	555%
7. Operating expenses associated with staff resources allocated to regulatory matters	ongoing							5,000	100%
8. Operating expenses associated with other resources allocated to regulatory matters (please identify the resources)									
9. Other regulatory agency fees or assessments	ongoing	13,400	13,532	16,685	23%	20,340	22%	20,700	2%
10. Any other costs for regulatory matters (please define)									

CNPI-Port Colborne

Regulatory Cost Category	Ongoing or One-time Cost?	2006 Board Approved	2006 Actual	2007 Actual	% Change in 2007 vs. 2006	2008 Bridge Year	% Change in 2008 vs. 2007	2009 Test Year	% Change in 2009 vs. 2008
1. OEB Annual Assessment	ongoing			32,020	100%	34,300	7%	34,300	0%
2. OEB Hearing Assessments (applicant initiated)									
3. OEB Section 30 Costs (OEB initiated)									
4. Expert Witness cost for regulatory matters									
5. Legal costs for regulatory matters	ongoing		15,874	9,964	-37%		-100%	8,333	100%
6. Consultants costs for regulatory matters	ongoing		4,746	192	-96%	5,000	2504%	11,467	129%
7. Operating expenses associated with staff resources allocated to regulatory matters	ongoing	13,492	53,134	46,440	-13%	31,109	-33%	40,008	29%
8. Operating expenses associated with other resources allocated to regulatory matters (please identify the resources)									
9. Other regulatory agency fees or assessments	ongoing	8,100	8,131	10,266	26%	12,500	22%	12,500	0%
10. Any other costs for regulatory matters (please define)									

CNPI-Gananoque

Regulatory Cost Category	Ongoing or One-time Cost?	2006 Board Approved	2006 Actual	2007 Actual	% Change in 2007 vs. 2006	2008 Bridge Year	% Change in 2008 vs. 2007	2009 Test Year	% Change in 2009 vs. 2008
1. OEB Annual Assessment	ongoing			12,073	100%	13,800	14%	13,800	0%
2. OEB Hearing Assessments (applicant initiated)									
3. OEB Section 30 Costs (OEB initiated)									
4. Expert Witness cost for regulatory matters									
5. Legal costs for regulatory matters	ongoing		10,439	3,691	-65%	-	-100%	8,333	100%
6. Consultants costs for regulatory matters	ongoing		4,747	192	-96%	2,800	1358%	9,134	226%
7. Operating expenses associated with staff resources allocated to regulatory matters	ongoing	24,714	53,134	46,440	-13%	31,109	-33%	40,008	29%
8. Operating expenses associated with other resources allocated to regulatory matters (please identify the resources)									
9. Other regulatory agency fees or assessments	ongoing	3,150	3,187	3,900	22%	4,750	22%	4,850	2%
10. Any other costs for regulatory matters (please define)									

b) The ongoing costs include the regulatory costs for the 2009 Rate Application, in the 2009 Test Year, which will be expensed over three years of the 3^{rd} Generation IRM process.

c) N/A

INTERROGATORY # 45 - Adequacy of skilled staffing

Interrogatories common to all three applications

Ref: Exhibit 4/Tab 2/Schedule 5, Appendix A

The forecast for FTE are given on this exhibit. Considering the industry wide issue of an aging skilled workforce, what plans are in the forecast to ensure adequate skilled staffing in the future as these employees retire?

RESPONSE:

Succession planning is a key component of CNPI's human resources strategy, and succession plans have been developed and continue to be updated. These plans provide a means for forecasting and identifying the required skill sets for future resource needs before they arise. Integral to succession planning is CNPI's commitment to the training and development of key personnel. Programs are in place to formulate individualized developmental plans for high potential candidates identified in the succession planning process. These strategies position CNPI to be adequately prepared for any skilled staffing requirements that may arise in the future.

INTERROGATORY # 46 - Productivity Targets

Interrogatories common to all three applications

Ref: Exhibit 1/Tab 2/Schedule 2

This exhibit describes CNPI's budget process.

a) Please describe any cost efficiency programs that are either in place now or planned in the budget.

b) Please describe the nature of any such program and the scope of the benefits envisioned in the planning horizon for the budget

c) Are the efficiency programs successes measurable?

RESPONSE:

a) CNPI continues to look for opportunities to reduce costs as evidenced by the modest increases in the operating expenses for the distribution business units. Historically, CNPI used programs such as the 2007 ERW and automation of previously manual processes to reduce operating expenditures. All managers have as part of their short term incentive compensation, a performance target to reduce their department's operating expenditure budget below plan. In addition to these cost efficiency initiatives, there is a constant reminder to all employees the need maintain or reduce costs in an effort to increase efficiencies for the benefit of the customer. CNPI is also pursuing possible mergers and acquisitions involving other LDC's in an effort to promote improved economics of scale in service delivery. These acquisitions may also result in service agreements with CNPI, providing revenue which allows CNPI to offset certain operating costs and benefit ratepayers.

b) N/A

c) N/A

INTERROGATORY # 47 - Incentive compensation

Interrogatories common to all three applications

Ref: Exhibit 4/Tab 2/Schedule 5, page 4.

A list of six corporate targets is given in this exhibit for the short-term incentive compensation. This evidence describes the benefits of such programs. In better understanding the incentive/performance relationship, please provide the following information:

a) Are the programs described in response to 45a) above tied to these incentives?

b) Are the performance targets for the employees set as personal goals to achieve?

c) Are the performance targets for the employees measurable?

RESPONSE:

a) The programs described in response to 45(a) are in relation to succession planning, and the corporate targets are in respect of our short-term incentive program, which is a separate and distinct human resources program.

b) The short-term incentive program includes both an individual and a corporate component for all Executive, Management and Non-union staff. These individual targets are set as personal goals to achieve. The Applications do not include costs related to performance targets that are “primarily shareholder related”.

c) Yes.

INTERROGATORY # 48 - Operating Costs

CNPI – EOP specific interrogatories

Ref: Exhibit 4/Tab 1/Schedule 1

The figures in Table 1 below 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. Please confirm the utility's agreement with the numbers for Total OM&A Expenses that are summarized in Table 1.

Table 1

		Col. 1	*Col. 2*	*Col. 3*
		2003	**2004**	**2005**
1	**Operation**	$225,186	$257,502	$243,559
2	**Maintenance**	$101,467	$148,402	$164,644
3	**Billing and Collection**	$37,478	$335,698	$240,109
4	**Community Relations**	$5,166	$2,168	$347
5	**Administrative and General Expenses**	$798,375	$256,077	$577,447
6	**Total OM&A Expenses**	**$1,169,675**	**$1,001,850**	**$1,228,110**

a) Please confirm the utility's agreement with the numbers for Total OM&A Expenses that are summarized in Table 1.

Board staff prepared Table 2 below to review CNPI's OM&A expenses. Note rounding differences may occur, but are immaterial to the questions below.

Table 2

		Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*
		2006 Bd Appr.	**2006 Actual**	**2007**	**2008 Bridge**	**2009 Test**
1	**Operation**	257,502	286,543	211,361	234,418	250,755
2	**Maintenance**	173,348	155,026	192,808	242,150	205,570
3	**Billing and Collection**	310,698	286,279	267,986	258,419	269,081
4	**Community Relations**	2,160	-	951	2,450	4,000
5	**Administrative and General Expenses**	575,355	656,664	514,893	424,408	462,469
6	**Total**	1,319,063	1,384,512	1,187,999	1,161,845	1,191,875

Board Staff Table 3 below was created to review CNPI's OM&A forecasted expenses from the evidence provided in the application's Exhibit 4. Note rounding differences may occur, but are immaterial to the following questions.

Table 3

Eastern Ontario Power (CNP)

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10
		2006 Board Approved	Variance 2006/2006	**2006** Actual	Variance 2007/2006	**2007** Actual	Variance 2008/2007	**2008** Bridge	Variance 2009/2008	**2009** Test	Variance 2009/2006
1	Operation	257,502	29,041	286,543	-75,182	211,361	23,057	234,418	16,337	250,755	-35,788
2			*11.3%*		*-26.2%*		*10.9%*		*7.0%*		***-12.5%***
3	Maintenance	173,348	-18,322	155,026	37,782	192,808	49,342	242,150	-36,580	205,570	50,544
4			*-10.6%*		*24.4%*		*25.6%*		*-15.1%*		***32.6%***
5	Billing & Collections	310,698	-24,419	286,279	-18,293	267,986	-9,567	258,419	10,662	269,081	-17,198
6			*-7.9%*		*-6.4%*		*-3.6%*		*4.1%*		***-6.0%***
7	Community Relations	2,160	-2,160	0	951	951	1,499	2,450	1,550	4,000	4,000
8			*-100.0%*		*#DIV/0!*		*157.6%*		*63.3%*		***#DIV/0!***
9	Administrative and General Expenses	575,355	81,309	656,664	-141,771	514,893	-90,485	424,408	38,061	462,469	-194,195
10			*14.1%*		*-21.6%*		*-17.6%*		*9.0%*		***-29.6%***
11	Total OM&A Expenses	**1,319,063**	**65,449**	**1,384,512**	**-196,513**	**1,187,999**	**-26,154**	**1,161,845**	**30,030**	**1,191,875**	**-192,637**
12			4.96%		-14.19%		-2.20%		2.58%		***-13.91%***

b) Please confirm that CNPI agrees with the two tables prepared by Board Staff presented above. If CNPI does not agree with any table please advise why not. If CNPI determines that the tables require corrections, please provide amended tables with full explanation of changes made.

c) Please complete Table 4 by identifying the key cost drivers that are contributing to the overall increase of 13.9% over 2006 Historical relative to 2009.

Table 4

		Col. 1	*Col. 2*	*Col. 3*	*Col. 4*
		2006	**2007**	**2008**	**2009**
	Opening Balances	**1,319,063**	**1,384,512**	**1,187,999**	**1,161,845**
1	Cost Driver 1				
2	Cost Driver 2				
3	Cost Driver 3				
4	Cost Driver 4				
…	Etc.				
	Closing Balances	**1,384,512**	**1,187,999**	**1,161,845**	**1,191,875**

RESPONSE:

a) CNPI-Gananoque agrees with the numbers in Table 1.

b) CNPI-Gananoque agrees with the numbers in Tables 2 and 3.

c) The change from 2006 Board Approved to 2009 Test Year is an overall decrease of 13.9%. Refer to Table 4 below.

Table 4

		Col. 1	*Col. 2*	*Col. 3*	*Col. 4*
		2006	**2007**	**2008**	**2009**
	Opening Balances	**1,319,063**	**1,384,512**	**1,187,999**	**1,161,845**
1	PCB testing and servicing	**82,400**	**(91,100)**	**29,500**	**(26,000)**
2	Vegetation management	**40,900**	**33,100**		
3	Capital construction program	**(101,000)**		**(22,500)**	
4	Closed customer service office	**(24,600)**			
5	Property maintenance	**44,600**	**(19,900)**		
6	Low voltage wheeling	**(107,300)**			
7	Office supplies and expenses	**11,700**	**3,600**	**9,100**	**(6,700)**
8	Revised shared cost allocations	**119,000**	**(47,000)**	**(62,000)**	**17,000**
9	Move to company owned building		**(81,600)**		
10	2007 ERW costs		**15,300**	**(15,300)**	
11	Mapping and system documentation			**17,200**	
12	Meter Expense			**15,700**	
13	General salary and incentive				**18,900**
14	Rate Application				**20,000**
15	Miscellaneous other	**(251)**	**(8,913)**	**2,146**	**6,830**
	Closing Balances	**1,384,512**	**1,187,999**	**1,161,845**	**1,191,875**

Note – The above table reconciles the yearly changes in operating expenses. The cost drivers, both increases and decreases, are reproduced from the variance analysis included in Exhibit 4/Tab 2/Schedule 3, Appendix A/B/C. The identified cost drivers are the primary reason for the change in the account balances.

INTERROGATORY # 49 - Contracted services from third parties

CNPI – EOP specific interrogatories

Ref: Exhibit 4/Tab 2/Schedule 1

a) For the 2009 test year, what portion of total OM&A expenses is related to contracted services from third parties?

b) Please identify how these contracted services are selected?

c) For each contracted service, please identify the year in which a tendering process was used to obtain the contract.

RESPONSE:

a) For the 2009 Test Year, the portion of total OM&A expenses related to contracted services from third parties is $120,140.

b) Contracted services are generally selected through our purchasing practice involving a requisition of required materials or services needed by a department to complete their duties, tasks, assignments or projects. This requisition then goes through a requisition approval process. This process involves the following steps:

   1. Review of requisition to ensure it contains the required information to be properly processed.
   2. Requisition processing, monitoring and determination of whether a request for quotation or a request for proposal is required.
   3. Request for quotations are required for any purchases where the anticipated amount will be over $10,000, the scope and specifications are clearly identified and stated, and it does not meet the sole sourcing criteria (sole source purchasing may be used in exceptional circumstances for purchases under $10,000 or for purchases over $10,000 provided certain parameters are met). Generally, a minimum of three quotations, but no less than two quotations are required.

4. Requests for proposal are required for any purchases where the anticipated amount will be over $10,000, and the vendor will be supplying the scope and specifications, and it does not meet the sole sourcing criteria.
5. Quotations and proposals are analyzed by the materials management group. The lowest price quote is generally selected unless there are extenuating circumstances upon which this should not occur. e.g. – delivery date, quality factor, warranties, etc.

c) For contracted services over $10,000, the table below provides information identifying the year in which the tendering process was used to obtain the contract:

OEB Account #	Description	Amount	Year Tendered
5020, 5120 & 5175	Overhead Distribution Lines and Feeders, Maint. of Poles, Towers & Fixtures & Maint. of Meters	$5,100	N/A
5135	Overhead Distribution Lines & Feeder ROW	$70,000	2007, 2008 & 2009
5065	Utilismart	$34,800	2003
5675	Service Center	$6,240	N/A
5420 & 5425	Community Safety Program & Misc. Customer Service	$4,000	N/A
	TOTAL	**$120,140**	

INTERROGATORY # 50 - Charitable donations

CNPI – EOP specific interrogatories

Ref: Exhibit 4/Tab 2/Schedule 2

Please confirm that charitable donations are not included in the revenues sought from utility ratepayers.

RESPONSE:

All charitable donations are funded through the unregulated business and are not included in the revenue requirement.

INTERROGATORY # 51 - Operating Costs

CNPI – Fort Erie specific interrogatories

Ref: Exhibit 4/Tab 1/Schedule 1

The figures in Table 1 below 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. Please confirm the utility's agreement with the numbers for Total OM&A Expenses that are summarized in Table 1.

Table 1

		Col. 1	*Col. 2*	*Col. 3*
		2003	**2004**	**2005**
1	**Operation**	$739,002	$714,745	$869,059
2	**Maintenance**	$833,420	$932,164	$890,055
3	**Billing and Collection**	$581,062	$849,730	$1,016,664
4	**Community Relations**	$2,434	$4,234	$1,322
5	**Administrative and General Expenses**	$1,413,592	$1,344,862	$1,109,075
6	**Total OM&A Expenses**	**$3,571,514**	**$3,847,739**	**$3,888,181**

a) Please confirm the utility's agreement with the numbers for Total OM&A Expenses that are summarized in Table 1.

Board staff prepared Table 2 below to review CNPI's OM&A expenses. Note rounding differences may occur, but are immaterial to the questions below.

Table 2

		Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*
		2006 Bd Appr.	**2006 Actual**	**2007**	**2008 Bridge**	**2009 Test**
1	**Operation**	714,745	1,356,505	914,403	791,762	841,410
2	**Maintenance**	934,204	686,312	1,021,025	1,015,734	1,013,416
3	**Billing and Collection**	796,730	1,034,116	1,019,329	1,021,251	946,160
4	**Community Relations**	4,234	2,661	6,788	14,500	43,830
5	**Administrative and General Expenses**	1,869,376	1,464,801	1,872,730	1,588,543	1,645,174
6	**Total**	4,319,289	4,544,395	4,834,275	4,431,790	4,489,990

Board Staff Table 3 below was created to review CNPI's OM&A forecasted expenses from the evidence provided in the application's Exhibit 4. Note rounding differences may occur, but are immaterial to the following questions.

Table 3

Fort Erie (CNP)

		Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*	*Col. 6*	*Col. 7*	*Col. 8*	*Col. 9*	*Col. 11*
		2006 Board Approved	Variance 2006/2006	**2006** Actual	Variance 2007/2006	**2007** Actual	Variance 2008/2007	**2008** Bridge	Variance 2009/2008	**2009** Test	Variance 2009/2006
1	Operation	714,745	641,760	1,356,505	-442,102	914,403	-122,641	791,762	49,648	841,410	-515,095
2			*89.8%*		*-32.6%*		*-13.4%*		*6.3%*		***-38.0%***
3	Maintenance	934,204	-247,892	686,312	334,713	1,021,025	-5,291	1,015,734	-2,318	1,013,416	327,104
4			*-26.5%*		*48.8%*		*-0.5%*		*-0.2%*		***47.7%***
5	Billing & Collections	796,730	237,386	1,034,116	-14,787	1,019,329	1,922	1,021,251	-75,091	946,160	-87,956
6			*29.8%*		*-1.4%*		*0.2%*		*-7.4%*		***-8.5%***
7	Community Relations	4,234	-1,573	2,661	4,127	6,788	7,712	14,500	29,330	43,830	41,169
8			*-37.2%*		*155.1%*		*113.6%*		*202.3%*		***1547.1%***
9	Administrative and General Expenses	1,869,376	-404,575	1,464,801	407,929	1,872,730	-284,187	1,588,543	56,631	1,645,174	180,373
10			*-21.6%*		*27.8%*		*-15.2%*		*3.6%*		***12.3%***
11	**Total OM&A Expenses**	**4,319,289**	**225,106**	**4,544,395**	**289,880**	**4,834,275**	**-402,485**	**4,431,790**	**58,200**	**4,489,990**	**-54,405**
12			5.21%		6.38%		-8.33%		1.31%		***-1.20%***

b) Please confirm that CNPI agrees with the two tables prepared by Board Staff presented above. If CNPI does not agree with any table please advise why not. If CNPI determines that the tables require corrections, please provide amended tables with full explanation of changes made.

c) Please complete Table 4 by identifying the key cost drivers that are contributing to the overall increase of 13.9% over 2006 Historical relative to 2009.

Table 4

		Col. 1	*Col. 2*	*Col. 3*	*Col. 4*
		2006	**2007**	**2008**	**2009**
	Opening Balances	**1,319,063**	**1,384,512**	**1,187,999**	**1,161,845**
1	Cost Driver 1				
2	Cost Driver 2				
3	Cost Driver 3				
4	Cost Driver 4				
…	Etc.				
	Closing Balances	**1,384,512**	**1,187,999**	**1,161,845**	**1,191,875**

RESPONSE:

a) CNPI-Fort Erie agrees with the numbers in Table 1.

b) CNPI-Fort Erie agrees with the numbers in Tables 2 and 3.

c) The change from 2006 Board Approved to 2009 Test Year is an overall decrease of 1.2%. Refer to Table 4 below.

Table 4

		Col. 1	*Col. 2*	*Col. 3*	*Col. 4*
		2006	**2007**	**2008**	**2009**
	Opening Balances	**4,319,289**	**4,544,395**	**4,834,275**	**4,431,790**
1	Operations labour/Rankine	**387,600**			
2	Customer service supervisor	**78,000**			
3	Revised shared cost allocations	**(639,000)**	**(146,000)**	**150,000**	**(149,000)**
4	Base salary increase	**288,400**			**75,000**
5	Office supplies and expenses	**(165,500)**	**(56,200)**		
6	Empolyee pension and benefit	**374,400**	**184,000**	**(304,200)**	
7	Regulatory asset settlement	**(147,600)**	**147,600**		
8	2007 ERW costs		**184,000**	**(184,000)**	
9	Staff reductions		**(227,800)**	**(235,800)**	
10	Maintenance of meters	**59,800**	**83,000**		
11	Software maintenance		**65,000**		
12	Property maintenance		**56,700**	**46,000**	**112,400**
13	Property insurance			**19,800**	
14	Outside services			**103,800**	
15	Rate Application				**19,300**
16	Miscellaneous other	**(10,994)**	**(420)**	**1,915**	**500**
	Closing Balances	**4,544,395**	**4,834,275**	**4,431,790**	**4,489,990**

Note – The above table reconciles the yearly changes in operating expenses. The cost drivers, both increases and decreases, are reproduced from the variance analysis included in Exhibit 4/Tab 2/Schedule 3, Appendix A/B/C. The identified cost drivers are the primary reason for the change in the account balances.

INTERROGATORY # 52 - Contracted services from third parties

CNPI – Fort Erie specific interrogatories

Ref: Exhibit 4/Tab 2/Schedule 1

a) For the 2009 test year, what portion of total OM&A expenses is related to contracted services?

b) Please identify how these contracted services are selected?

c) For each contracted service, please identify the year in which a tendering process was used to obtain the contract.

RESPONSE:

a) For the 2009 Test Year, the portion of total OM&A expenses related to contracted services from third parties is $610,252.

b) Contracted services are generally selected through our purchasing practice involving a requisition of required materials or services needed by a department to complete their duties, tasks, assignments or projects. This requisition then goes through a requisition approval process. This process involves the following steps:

1. Review of requisition to ensure it contains the required information to be properly processed.
2. Requisition processing, monitoring and determination of whether a request for quotation or a request for proposal is required.
3. Request for quotations are required for any purchases where the anticipated amount will be over $10,000, the scope and specifications are clearly identified and stated, and it does not meet the sole sourcing criteria (sole source purchasing may be used in exceptional circumstances for purchases under $10,000 or for purchases over $10,000 provided certain parameters are met). Generally, a minimum of three quotations, but no less than two quotations are required.

4. Requests for proposal are required for any purchases where the anticipated amount will be over $10,000, and the vendor will be supplying the scope and specifications, and it does not meet the sole sourcing criteria.
5. Quotations and proposals are analyzed by the materials management group. The lowest price quote is generally selected unless there are extenuating circumstances upon which this should not occur. e.g. – delivery date, quality factor, warranties, etc.

c) For contracted services over $10,000, the table below provides information identifying the year in which the tendering process was used to obtain the contract:

OEB Account #	Description	Amount	Year Tendered
5175	Maint. of Meters	$19,200	2001
5135	Overhead Distribution Lines & Feeder ROW	$216,000	2008
5065	Utilismart	$48,000	2003
5630	Information Technology	$40,000	2008
5360 & 5399	Health & Safety & Customer Service	$7,980	N/A
5310	Customer Reads	$144,000	Original 1995, Renewed 2003
5420 & 5340	Community Safety Program & General C.S. Expense	$8,472	N/A
5425	Misc. C.S. & Info. Expense	$9,000	N/A
5675	Service Center Maint.	*$117,600	N/A
	TOTAL	**$610,252**	

* This amount represents the total value the total value of the combined services supplied to CNPI service center by approximately twenty different suppliers. The average value per supplier is approximately $5,800.

INTERROGATORY # 53 - Charitable donations

CNPI – Fort Erie specific interrogatories

Ref: Exhibit 4/Tab 2/Schedule 2

Please confirm that charitable donations are not included in the revenues sought from utility ratepayers.

RESPONSE:

All charitable donations are funded through the unregulated business and are not included in the revenue requirement.

INTERROGATORY # 54 - Operating Costs

CNPI – Port Colborne specific interrogatories

Ref: Exhibit 4/Tab 1/Schedule 1

The figures in Table 1 below 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. Please confirm the utility's agreement with the numbers for Total OM&A Expenses that are summarized in Table 1.

Table 1

		Col. 1	*Col. 2*	*Col. 3*
		2003	**2004**	**2005**
1	**Operation**	$249,857	$328,347	$307,178
2	**Maintenance**	$437,386	$368,661	$386,448
3	**Billing and Collection**	$533,507	$664,533	$509,652
4	**Community Relations**	$0	$0	$0
5	**Administrative and General Expenses**	$305,728	$316,059	$2,749,691
6	**Total OM&A Expenses**	**$1,528,481**	**$1,679,605**	**$3,954,974**

a) Please confirm the utility's agreement with the numbers for Total OM&A Expenses that are summarized in Table 1.

Board staff prepared Table 2 below to review CNPI's OM&A expenses. Note rounding differences may occur, but are immaterial to the questions below.

Table 2

		Col. 1 **2006 Bd Appr.**	*Col. 2* **2006 Actual**	*Col. 3* **2007**	*Col. 4* **2008 Bridge**	*Col. 5* **2009 Test**
1	**Operation**	714,745	1,356,505	914,403	791,762	841,410
2	**Maintenance**	934,204	686,312	1,021,025	1,015,734	1,013,416
3	**Billing and Collection**	796,730	1,034,116	1,019,329	1,021,251	946,160
4	**Community Relations**	4,234	2,661	6,788	14,500	43,830
5	**Administrative and General Expenses**	1,869,376	1,464,801	1,872,730	1,588,543	1,645,174
6	**Total**	4,319,289	4,544,395	4,834,275	4,431,790	4,489,990

Board Staff Table 3 below was created to review CNPI's OM&A forecasted expenses from the evidence provided in the application's Exhibit 4. Note rounding differences may occur, but are immaterial to the following questions.

Table 3

Port Colborne (CNP)

		Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*	*Col. 6*	*Col. 7*	*Col. 8*	*Col. 9*	*Col. 11*
		2006 Board Approved	Variance 2006/2006	**2006** Actual	Variance 2007/2006	**2007** Actual	Variance 2008/2007	**2008** Bridge	Variance 2009/2008	**2009** Test	Variance 2009/2006
1	Operation	328,347	92,242	420,589	93,583	514,172	-112,736	401,436	9,267	410,703	-9,886
2			*28.1%*		*22.3%*		*-21.9%*		*2.3%*		***-2.4%***
3	Maintenance	370,866	8,896	379,762	73,764	453,526	13,980	467,506	78,247	545,753	165,991
4			*2.4%*		*19.4%*		*3.1%*		*16.7%*		***43.7%***
5	Billing & Collections	584,533	-56,715	527,818	129,811	657,629	-61,590	596,039	16,480	612,519	84,701
6			*-9.7%*		*24.6%*		*-9.4%*		*2.8%*		***16.0%***
7	Community Relations	0	0	0	1,847	1,847	4,453	6,300	17,398	23,698	23,698
8			*#DIV/0!*		*#DIV/0!*		*241.1%*		*276.2%*		***#DIV/0!***
9	Administrative and General Expenses	2,461,450	-34,923	2,426,527	34,049	2,460,576	25,651	2,486,227	6,289	2,492,516	65,989
10			*-1.4%*		*1.4%*		*1.0%*		*0.3%*		***2.7%***
11	**Total OM&A Expenses**	**3,745,196**	**9,500**	**3,754,696**	**333,054**	**4,087,750**	**-130,242**	**3,957,508**	**127,681**	**4,085,189**	**330,493**
12			0.25%		8.87%		-3.19%		3.23%		***8.80%***

b) Please confirm that CNPI agrees with the two tables prepared by Board Staff presented above. If CNPI does not agree with any table please advise why not. If CNPI determines that the tables require corrections, please provide amended tables with full explanation of changes made.

c) Please complete Table 4 by identifying the key cost drivers that are contributing to the overall increase of 13.9% over 2006 Historical relative to 2009.

Table 4

		Col. 1	*Col. 2*	*Col. 3*	*Col. 4*
		2006	**2007**	**2008**	**2009**
	Opening Balances	**1,319,063**	**1,384,512**	**1,187,999**	**1,161,845**
1	Cost Driver 1				
2	Cost Driver 2				
3	Cost Driver 3				
4	Cost Driver 4				
…	Etc.				
	Closing Balances	**1,384,512**	**1,187,999**	**1,161,845**	**1,191,875**

RESPONSE:

a) CNPI-Port Colborne agrees with the numbers in Table 1.

b) CNPI-Port Colborne agrees with the numbers in Table 3. The numbers in Table 2 appear to be CNPI-Fort Erie's numbers. The corrected Table 2 is below.

Table 2

		Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*
		2006	**2006**	**2007**	**2008**	**2009**
		BD Approved	**Actual**	**Actual**	**Bridge**	**Test**
1	Operation	328,347	420,589	514,172	401,436	410,703
2	Maintenance	370,866	379,762	453,526	467,506	545,753
3	Billing and Collection	584,533	527,818	657,629	596,039	612,519
4	Community Relations			1,847	6,300	23,698
5	Administrative and General Exoenses	2,461,450	2,426,527	2,460,576	2,486,227	2,492,516
6	Total	3,745,196	3,754,696	4,087,750	3,957,508	4,085,189

c) The change from 2006 Board Approved to 2009 Test Year is an overall increase of 8.8%. Refer to Table 4 below.

Table 4

		Col. 1	*Col. 2*	*Col. 3*	*Col. 4*
		2006	**2007**	**2008**	**2009**
	Opening Balances	**3,745,196**	**3,754,696**	**4,087,750**	**3,957,508**
1	Vegetation management	**99,000**	**(81,500)**		**42,800**
2	Revised shared cost allocations	**(114,000)**	**41,000**	**86,000**	**45,000**
3	Transition costs settlement	**99,000**	**(99,000)**		
4	Meter reading expense	**(58,500)**			
5	Property insurance	**(9,200)**		**9,500**	
6	Load dispatching		**40,200**		
7	Property maintenance		**30,400**		
8	Customer service training costs		**52,600**		
9	2007 ERW costs		**100,000**	**(100,000)**	
10	Bad debt expense		**46,600**	**(26,400)**	**26,000**
11	Distribution maintenance activities		**169,200**		
12	Operations supervision		**26,200**		
13	Staff reductions			**(148,000)**	
14	Maintenance of meters			**56,000**	
15	Rate Application				**19,800**
16	Miscellaneous other	**(6,800)**	**7,354**	**(7,342)**	**(5,919)**
	Closing Balances	**3,754,696**	**4,087,750**	**3,957,508**	**4,085,189**

Note – The above table reconciles the yearly changes in operating expenses. The cost drivers, both increases and decreases, are reproduced from the variance analysis included in Exhibit 4/Tab 2/Schedule 3, Appendix A/B/C. The identified cost drivers are the primary reason for the change in the account balances.

INTERROGATORY # 55 - Contracted services from third parties

<u>CNPI – Port Colborne specific interrogatories</u>

Ref: Exhibit 4/Tab 2/Schedule 1

a) For the 2009 test year, what portion of total OM&A expenses is related to contracted services?

b) Please identify how these contracted services are selected?

c) For each contracted service, please identify the year in which a tendering process was used to obtain the contract.

RESPONSE:

a) For the 2009 Test Year, the portion of total OM&A expenses related to contracted services from third parties is $306,988.

b) Contracted services are generally selected through our purchasing practice involving a requisition of required materials or services needed by a department to complete their duties, tasks, assignments or projects. This requisition then goes through a requisition approval process. This process involves the following steps:

   1. Review of requisition to ensure it contains the required information to be properly processed.
   2. Requisition processing, monitoring and determination of whether a request for quotation or a request for proposal is required,
   3. Request for quotations are required for any purchases where the anticipated amount will be over $10,000, the scope and specifications are clearly identified and stated, and it does not meet the sole sourcing criteria (sole source purchasing may be used in exceptional circumstances for purchases under $10,000 or for purchases over $10,000 provided certain parameters are met). Generally, a minimum of three quotations, but no less than two quotations are required.

4. Requests for proposal is required for any purchases where the anticipated amount will be over $10,000, and the vendor will be supplying the scope and specifications, and it does not meet the sole sourcing criteria.
5. Quotations and proposals are analyzed by the materials management group. The lowest price quote is generally selected unless there are extenuating circumstances upon which this should not occur. e.g. – delivery date, quality factor, warranties, etc.

c) For contracted services over $10,000, the table below provides information identifying the year in which the tendering process was used to obtain the contract:

OEB Account #	Description	Amount	Year Tendered
5175	Maint. of Meters	$24,000	2001
5135	Overhead Distribution Lines & Feeder ROW	$120,000	2008
5065	Utilismart	$62,400	2003
5675	General Maint.	*$18,000	N/A
5399	Customer Service	$4,980	N/A
5310	Customer Reads	$68,400	2006
5420, 5425 & 5340	Community Safety Program, Misc. Customer Service & General C.S	$9,208	N/A
	TOTAL	**$306,988**	

* This amount represents the total value the total value of the combined services supplied to CNPI service center by a number of different suppliers. The average value per supplier is approximately $5,800.

INTERROGATORY # 56 - Charitable donations

CNPI – Port Colborne specific interrogatories

Ref: Exhibit 4/Tab 2/Schedule 2

Please confirm that charitable donations are not included in the revenues sought from utility ratepayers.

RESPONSE:

All charitable donations are funded through the unregulated business and are not included in the revenue requirement.

INTERROGATORY # 57 - Determination of Loss Adjustment Factors

CNPI – EOP specific interrogatories

References:
Exhibit 4, Tab 2, Schedule 8, Page 1
Exhibit 4, Tab 2, Schedule 8, Page 2
Exhibit 4, Tab 2, Schedule 8, Page 4
"Loss Factors" - Exhibit 9, Tab 1, Schedule 1, Appendix A
Exhibit 1, Tab 1, Schedule 2, Appendix A, Page 3
Exhibit 1, Tab 1, Schedule 12, Page 1
Tariff of Rates and Charges, Effective May 1, 2006 (RP-2005-0020/EB-2005-0346)

- 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 the proposed loss factors for 2009.
- The 3rd reference provides an explanation of losses in the distribution system of the host distributor Hydro One.
- The 4th reference provides 2006 EDR Board approved and proposed (2009) loss factors.
- The 5th reference provides proposed TLF for 2009.
- The 6th reference provides an explanation of host and embedded utilities.
- The 7th reference provides TLF effective May 1, 2006 in the Tariff of Rates and Charges.

a) With respect to the table in the 1st reference:
  - Please confirm if the correct formulaic representation of "Total Supply – No Losses" is "G=D-E+F" rather than "G=D-E-F".
  - Please confirm if the correct formulaic representation of "Total Loss Factor" is "M=N*H" rather than "M=C*I".

b) With respect to the table in the 2nd reference, please confirm if the 2nd label "Distribution Loss Factors" should be corrected to read "Total Loss Factors".

c) Losses within the distribution system of CNPI-EOP as reflected by "Distribution Loss Factor" in the 1st reference increase from 1.0093 in 2005 to 1.0350 in 2006 to 1.0870 in 2007.
  - Please explain reasons for the 835% increase in losses between 2005 and 2007 and confirm that the data underlying the calculations of these losses is correct.
  - Please describe any steps that are contemplated to decrease losses in the CNPI-EOP distribution system during the test year (2009) and/or during a longer planning period.

RESPONSE:

a) CNPI – Eastern Ontario Power confirms that the formulaic representation of "Total Supply – No Losses" should read "G=D-E+F" rather than "G=D-E-F". This was an editing error in the Application. The calculations in the table do reflect the correct representation "G=D-E+F".

CNPI – Eastern Ontario Power confirms that the correct formulaic representation of "Total Loss Factor" should read "M=N*H" rather than "M=C*I". This was an editing error in the Application. The calculations in the table do reflect the correct representation "M=N*H". In the final determination of the proposed "Total Loss Factor", CNPI – Eastern Ontario Power used the three year average "Effective Supply Facility Loss Factor" in Row H to compensate for varying amounts of generation being injected into the distribution system.

The corrected table is shown below with the editing corrections shown in bold type.

CNPI – Eastern Ontario Power, Determination of Loss Factors

Description	2006 EDR Board Approved	2005 Actual	2006 Actual	2007 Actual
Wholesale kWh - No Losses (A)		73,726,610	57,404,676	59,150,220
Wholesale kWh - With Losses (B)		76,233,315	59,356,435	61,161,327
Supply Facility Loss Factor (C=B/A)	1.0340	1.0340	1.0340	1.0340
Three Year Average				1.0340
Wholesale kWh - No Losses (D)		73,726,610	57,404,676	59,150,220
Embedded Wholesale Customers (E)		NIL	NIL	NIL
Embedded Generation – No Losses (F)		13,597,830	20,629,114	12,682,819
Total Supply – No Losses **(G=D-E+F)**		87,324,440	78,033,790	71,833,039
Effective Supply Facility Loss Factor		1.0287	1.0250	1.0280

(H=(B+F)/(A+F))				
Three Year Average(I)				1.0272
LTLT Physical Distributors (J)		NIL	NIL	NIL
Effective Supplied kWh (K=G+J)		87,324,440	78,033,790	71,833,039
Retail kWh (L)		86,515,636	75,398,070	66,086,052
Unaccounted For Energy (M=K-L)		808,804	2,635,720	5,746,987
Distribution Loss Factor (N=K/L)	1.0363	1.0093	1.0350	1.0870
Three Year Average				1.0438
Total Loss Factor **(M=N*H)**	1.0715	1.0383	1.0608	1.1166
Three Year Average				1.0719

b) CNPI – Eastern Ontario Power confirms that the second reference label "Distribution Loss Factors" should be corrected to read "Total Loss Factors". This was an editing error.

The corrected table is shown below with the editing corrections shown in bold type.

Loss Factors	
Supply Facility Loss Factor	1.0272
Distribution Loss Factors	
Secondary Metered Customer < 5,000 kW	1.0438
Primary Metered Customer < 5,000 kW	1.0336
Total Loss Factors	
Secondary Metered Customer < 5,000 kW	1.0719
Primary Metered Customer < 5,000 kW	1.0612

c) Part I - In 2006, CNPI – Eastern Ontario Power discovered an error in its Unbilled Revenue Program. The rate tables in the Program had not been updated to match the rate tables in the Customer Service System which were billing at the Board Approved Rates. As a result the Program returned incorrect data at year end. This error was not discovered until after year end amounts were posted. The 2005 quantities in the unbilled revenue projections were incorrect resulting in errors in the loss factor determination. This error was corrected in 2006 and the 2006 and 2007 quantities were projected correctly.

The 2006 Board Approved Distribution Loss Factor was 1.0363, this is in line with the 2006 reported Distribution Loss Factor of 1.035; a variance of 3.6%. However, in 2007, CNPI – Eastern Ontario Power is reporting a Distribution Loss Factor of 1.087, an increase of 149% over the 2006 value and 140% over the 006 Board Approved amount.

In its Application, CNPI – Eastern Ontario Power put forth several reasons for this increase in 2007. These were technical reasons but were impractical to quantify. The first related to the level of available generation in the spring of 2007 as compare to the corresponding base distribution load. At that time there was a reverse power relay on the delivery point from Hydro One Networks to CNPI – Eastern Ontario Power; at a time when generation may have been at its highest due to spring run off and distribution loads were at their lowest due to mild temperatures and off-tourist season, this relay detected energy flow from the distribution system into Hydro One Networks' system. The results were system outages to the entire distribution system in Gananoque. With cooperation from Hydro One Networks, this relaying functionality was defeated to prevent further outages. However, metering to measure reverse power flow was not installed until March 3, 2008. During the period the relaying was defeated until March 3, 2008, it is not possible to determine if energy purchases by CNPI – Eastern Ontario Power flowed unmetered from CNPI – Eastern Ontario Power's distribution system into Hydro One Networks' distribution system. Any unmetered energy flow of this nature would result in increased distribution losses.

The second reason relates to the mix of loads fed from the 44 kV, 27 kV and 4 kV distribution systems. Up until 2007, CNPI – Eastern Ontario Power had a significant distribution load serviced directly from it 44 kV and 27 kV distribution systems. By the end of 2007, CNPI – Eastern Ontario Power had lost approximately 23% of throughput and approximately 44% of billing demand as a result of plant closures; all of this lost load was serviced from the higher 44 kV and 27 kV distribution systems. Loads serviced from higher voltage distribution systems will inherently have lower loss percentages associated with them as compared to the same load serviced from lower voltage distribution systems. The resultant load mix (from a voltage level perspective) now has a greater percentage of loads serviced through the lower voltage system and consequently, as a percentage, has a greater loss factor.

d) Part II - The installation of the bi-directional meter in March 2008 will eliminate the possibility of unmetered energy leaving the system and will thus prevent it from influencing the distribution loss factor.

As explained earlier in this question, CNPI – Eastern Ontario Power believes that a contributing factor to the increase in the percentage of losses is the recent loss of the industrial load which was serviced on the higher voltage distribution facilities. This has been a recent occurrence and CNPI – Eastern Ontario has not yet evaluated any possible reconfiguration of the distribution system as a result of these customer reductions that could possibly contribute to loss reductions.

INTERROGATORY # 58 - Determination of Loss Adjustment Factors

CNPI – Fort Erie specific interrogatories

Ref:
Exhibit 4, Tab 2, Schedule 8, Page 1
Exhibit 4, Tab 2, Schedule 8, Page 2

- 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 loss factors proposed for 2009 and details of modifications and upgrades made to the distribution system to bring about an enduring reduction in CNPI-Fort Erie's DLF.

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 (1.0357) for the test year 2009 rather than a lower DLF such as the actual DLF for 2005 (1.0289).
b) Please provide details of losses pertaining to years 2003 and 2004 together with comments on whether recent performance demonstrates the success of the modifications and upgrades made to the distribution system provided in the 2nd reference.
c) Please explain the reason for proposing a SFLF of 1.0033 (2nd reference) that is different from the industry standard (1.0045).

RESPONSE:

a) As discussed in Interrogatory #57 c), CNPI experienced some anomalies with its unbilled revenue program at the end of 2005 which may have influenced the determination of the 2005 loss factor. CNPI – Fort Erie had an approved DLF of 1.0432 in its 2006 EDR; excluding the 2005 results CNPI – Fort Erie had a declining DLF through to 2007. CNPI – Fort Erie has interpreted this decline as an indicator that distribution projects including the conversion from a 4.8 kV delta distribution system to an 8.32 kV wye distribution system were contributing to a reduction in technical losses.

In addition, strengthened distribution ties between the two transmission stations allowed more maintenance to be done without transferring the entire distribution system load to one of the two transmission stations. Transferring the entire load to one of the two transmission stations results in a less effective distribution of electricity and can result in increased losses due to pattern of loading of the feeders.

In the first instance, the loss reductions associated with a voltage conversion is enduring. In the second instance, though increased transfer capability does enhance the operations related to maintenance, the opportunity, such as a failed transmission line or station, could require the transfer of an entire transmission station and thus additional losses would be incurred.

To employ a reasonable compromise, CNPI – Fort Erie opted to average the three years, including the lower value for 2005, yielding a distribution loss factor that is trending downward from the Board Approved 2006 EDR and the actuals for 2006 and 2007.

b) In the 2006 EDR, CNPI – Fort Erie reported a Total Loss Factor of 1.0479. This calculation was based on an accumulated calculation over the period of May 1, 2002 to July 31, 2005. In this Application CNPI – Fort Erie is forecasting a 2009 Total Loss Factor of 1.0391, a reduction of 0.8%.

It is intuitive to suggest that a continued conversion from a 4.8 kV three wire delta distribution system to an 8.32 kV four wire wye distribution system will have an enduring reduction in technical losses. Likewise, the expansion of the 34.5 kV distribution system to improve transfer capability between the stations has had an added advantage of converting some load that was on the 4.8 kV three wire delta distribution system to the 34.5 kV four wire wye distribution system; again the transfer of existing low voltage serviced load to a higher voltage serviced load will aid in loss reduction.

While it is difficult to quantifiably establish the contribution that these projects had to loss reduction, these initiatives have resulted in the reduction in the Total Loss Factor being forecasted.

c) As shown in the table provided in Exhibit 4, Tab 2, Schedule 8, page 1, the third row, Supply Facility Loss Factor (C=B/A), is the actual Supply Facility Loss Factor applied to the CNPI – Fort Erie monthly settlement. CNPI – Fort Erie opted to use this lower value (as compared to the industry standard, 1.0045) to reflect the actual loss factor being applied in settlement and to pass this lower loss factor along to its customers.

INTERROGATORY # 59 - Determination of Loss Adjustment Factors

CNPI – Port Colborne specific interrogatories

References:
Exhibit 4, Tab 2, Schedule 8, Page 1
Exhibit 4, Tab 2, Schedule 8, Page 2

- 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 loss factors proposed for 2009 and a rationale for using 2007 data as a basis for their determination.

a) The actual System Facility Loss Factor (SFLF), DLF and TLF for 2005 are shown as less than unity in the 1st reference. Please explain the rationale for the negative loss percentage implied by this and confirm that the data underlying the calculations of these losses is correct.

b) Notwithstanding the explanation provided in the 2nd reference for selecting the actual DLF for 2007 as the proposed DLF for 2009, please provide an explanation or rationale for not selecting a lower DLF such as the actual DLF for 2006 (1.0149) as the proposed DLF for 2009.

c) Please explain the reason for proposing a SFLF of 1.0052 (2nd reference) that is different from the industry standard (1.0045).

RESPONSE:

a) Similar to the circumstance discussed for CNPI – Eastern Ontario Power and CNPI – Fort Erie in Interrogatories #57 & 58, an anomaly with the unbilled revenue at the end of 2005 may have influenced the determination of the 2005 loss factor.

The Supply Facility Loss Factor, up until April 2006, was negative on the settlement reports for CNPI – Port Colborne. As shown in the table in Exhibit 4, Tab 2, Schedule 8, Page 1 the factor was 0.9976 for 2005. For the first four months of 2006, prior to the wholesale meter changes, it was 0.9998. In 2004 it was 0.9973.

b) CNPI – Port Colborne elected to go with the actual 2007 DLF as the proposed DLF for two primary reasons; the addition of Hydro One Networks as a customer and the operational behaviour changes forecasted for the embedded generators. Prior to December 2006, the load associated with the Hydro One Networks' embedded distribution, which is located at the end of a CNPI – Port Colborne feeder, was settled by Hydro One Networks with the IESO. Therefore the loads were not factored into CNPI – Port Colborne's settlement. With deregistration by Hydro One Networks, that energy is now settled by CNPI – Port Colborne with the IESO and sold to Hydro One networks at the retail meter located at the end of the feeder. The losses associated with this load now impact upon CNPI – Port Colborne.

The second cause is the operational behavioural changes forecasted for the two embedded generators. These load displacement generation facilities are located at the end of a heavily loaded 27.6 kV feeder. Historically, the embedded generators have met most of their own domestic load requirements, but as explained in the Application, are now becoming more dependent on electricity supplied by CNPI – Port Colborne. The losses associated with this operational behavioural change will impact upon CNPI – Port Colborne.

c) As shown in the table provided in Exhibit 4, Tab 2, Schedule 8, page 1, the third row, Supply Facility Loss Factor (C=B/A), is the actual Supply Facility Loss Factor applied to the CNPI – Port Colborne monthly settlement. CNPI – Port Colborne opted to use the value shown for 2009 because it reflects the enduring Supply Facility Loss Factor now that the wholesale metering points that were formerly maintained by Hydro One Networks, as the interim Meter Service Provider, have been replaced with new meters maintained by the enduring Meter Service Provider. The former wholesale meter points were located inside Hydro One Networks' transmission station, and, according to settlement reports, were attracting a loss factor of less than unity. Beginning in May 2006, the data from the new wholesale meter points, located outside of Hydro One Networks' transmission station were being used for settlement and were attracting a loss factor averaging 1.0052. CNPI – Port Colborne has elected 1.0052 as its Supply Facility Loss Factor because it is the factor applied to settlements.

INTERROGATORY # 60 – Taxes

Interrogatories common to all three applications

Ref: Exhibit 4/Tab 3/Schedule 2, 2007 Audited Financial Statements and Exhibit 1/Tab 3/Schedule 2 (pro forma financial statements) - Taxes

In Exhibit 4/Tab 3/Schedule 2, CNPI provides a spreadsheet deriving the tax expense allocated to each of the three operating service areas, based on a top-down derivation of CNPI's taxes on a corporate basis, then allocated between Transmission and Distribution, and finally allocated between the three service areas. The derivation is provided for 2006 and 2007 actual, 2008 and 2009 test years. Board staff has prepared the following table summarizing the utility and taxable income and tax expense from this exhibit in all three applications.

(Tables below)

CNPI Taxes (actual and forecasted) - per Exhibit 4 / Tab 3 / Schedule 2

Net Income (before addbacks and deductions)	**2006 Actual**	**2007 Actual**	**2008 Bridge**	**2009 Test**
All Operations	$ 2,141,257	$ 3,529,198	$ 348,000	$ 3,927,823
Transmission	$ 1,348,153	$ 3,178,959	-$ 181,000	$ 1,802,000
Distribution	$ 793,104	$ 350,239	$ 529,000	$ 2,125,823

Note: 2006, 2007, 2008 per financial statements; 2009 is regulated utility income.

Taxable Income	**2006 Actual**	**2007 Actual**	**2008 Bridge**	**2009 Test**
All Operations	$ 3,276,718	$ 5,344,019	$ 398,768	$ 3,953,457
Transmission	$ 2,874,196	$ 5,350,488	$ 347,993	$ 2,500,577
Distribution	$ 402,522	-$ 6,469	$ 50,795	$ 1,452,880

Taxes (Actual / Forecasted)	**2006 Actual**	**2007 Actual**	**2008 Bridge**	**2009 Test**
All Operations	$ 1,331,418	$ 2,098,652	$ 331,956	$ 1,710,151
Transmission	$ 1,044,060	$ 1,956,504	$ 163,484	$ 869,592
Distribution	$ 287,358	$ 142,148	$ 168,472	$ 840,559
Fort Erie (-0223)	$ 201,233	$ 95,244	$ 109,723	$ 538,151
Gananoque (-0222)	$ 29,478	$ 15,586	$ 22,024	$ 111,423
Port Colborne (-0224)	$ 56,647	$ 31,319	$ 36,724	$ 190,985

Distribution of Tax Payments (Actual and Forecasted)	**2006 Actual**	**2007 Actual**	**2008 Bridge**	**2009 Test**
Transmission	78.42%	93.23%	49.25%	50.85%
Distribution	21.58%	6.77%	50.75%	49.15%
Percentage of Distribution				
Fort Erie (-0223)	70.03%	67.00%	65.13%	64.02%
Gananoque (-0222)	10.26%	10.96%	13.07%	13.26%

Port Colborne (-0224)	19.71%	22.03%	21.80%	22.72%

Annual Percentage Changes	**2006 Actual**	**2007 Actual**	**2008 Bridge**	**2009 Test**	*3-year geometric average*
All Operations		57.63%	-84.18%	415.17%	8.70%
Transmission		87.39%	-91.64%	431.91%	-5.91%
Distribution		-50.53%	18.52%	398.93%	43.02%
Fort Erie (-0223)		-52.67%	15.20%	390.46%	38.80%
Gananoque (-0222)		-47.13%	41.31%	405.92%	55.77%
Port Colborne (-0224)		-44.71%	17.26%	420.06%	49.95%

In Exhibit 1/Tab 3/Schedule 1, CNPI provides its 2007 Audited Financial Statements ("AFS"). Note 16 of the AFS provides Segmented Information for transmission and the distribution operations in each of CNPI's three service areas. In Exhibit 1/Tab 3/Schedule 2 of each service area application, CNPI provides pro forma financial statements for that service area, showing 2007 Regulatory Actuals and 2008 and 2009 forecasts. Board staff has derived the following information based on the net earnings and taxes paid and forecasted from these exhibits below:

CNPI Taxes (per Audited Financial Statements and pro forma financial statements

Net Earnings	**2006 Actual**	**2007 Actual (AFS)**	**2007 Actual (pro forma)**	**2008 Bridge**	**2009 Test**
All Operations	$ 2,141,000	$ 3,529,000			
Transmission	$ 1,348,000	$ 3,178,000			
Distribution	$ 793,000	$ 351,000	$ 138,583	$ 432,760	$ 35,769
Fort Erie (-0223)	$ 440,000	$ 490,000	$ 126,318	$ 447,971	$ 317,534
Gananoque (-0222)	$ 108,000	$ 29,000	$ 87,339	$ 67,420	-$ 63,926
Port Colborne (-0224)	$ 245,000	-$ 168,000	-$ 75,074	-$ 82,631	-$ 217,839

Note: 2006 and 2007 from Note 16: Segement Information to 2007 Audited Financial Statements
Note: 2008 and 2009 forecasts taken from Exhibit 1/Tab 3/Schedule 2 (pro forma financial statements) of CNPI service area applications

Taxes	**2006 Actual**	**2007 Actual (AFS)**	**2007 Actual (pro forma)**	**2008 Bridge**	**2009 Test**
All Operations	$ 967,000	$ 1,725,000			
Transmission	$ 733,000	$ 1,580,000			
Distribution	$ 234,000	$ 145,000	$ 282,933	$ 404,000	$ 158,200

Fort Erie (-0223)	$ 94,000	$ 221,000	$ 318,591	$ 508,000	$ 383,200
Gananoque (-0222)	$ 44,000	$ 7,000	$ 26,240	-$ 26,000	-$ 70,600
Port Colborne (-0224)	$ 96,000	-$ 83,000	-$ 61,898	-$ 78,000	-$ 154,400

a) Please provide a detailed explanation of why the 2007 actuals for Net Earnings and Taxes differ between the 2007 Audited Financial Statements and the pro forma statements.
b) Please provide a detailed explanation of why the taxes derived in Exhibit 4/Tab 3/Schedule 2 differ from those shown in the Audited Financial Statements and pro forma financial statements.
a) Please provide an explanation for the year over year changes in net and taxable income and taxes calculated in Exhibit 4/Tab 3/Schedule 2 for:
   i. CNPI
   ii. Distribution;
   iii. Each of the three distribution service areas.

   In particular, please discuss what factors or tax planning CNPI has used or assumed for the 2008 bridge and 2009 test years.

RESPONSE:

a) Please see Tables below for a detailed reconciliation of the 2007 actual for net earnings and taxes to the 2007 Audited Financial Statements and the pro forma statements.

Table 1

	CNPI-Fort Erie	CNPI-Port Colborne	CNPI-Gananoque	Total Distribution
Net Earnings per Audited Financial Statements	$ 490,000	$ (168,000)	$ 29,000	$ 351,000
Removal of asset allocation charges*	(1,002,900)	297,756	100,116	(605,028)
Record depreciation re asset reallocations*	609,826	(222,287)	(50,493)	337,046
Remove non-recoverable STIs	29,776	17,753	8,796	56,325
Rounding differences	(384)	(296)	(80)	(760)
Net Earnings per pro forma statements	$ 126,318	$ (75,074)	$ 87,339	$ 138,583

Table 2

	CNPI-Fort Erie	CNPI-Port Colborne	CNPI-Gananoque	Total Distribution
Income Taxes per Audited Financial Statements	$ 221,000	$ (83,000)	$ 7,000	$ 145,000
Reallocated capital tax to income taxes	98,159	20,891	19,059	138,109
Rounding differences	(568)	211	181	(176)
Taxes per pro forma statements	$ 318,591	$ (61,898)	$ 26,240	$ 282,933

* See Exhibit 1, Tab 3, Schedule 1, page 2

b) The Audited Financial Statements are based on an accounting provision calculated at year end and include future taxes. Exhibit 4/Tab 3/Schedule 2 is based on the actual 2007 income tax return filed. Please see Table below for a detailed reconciliation of the taxes in Exhibit 4/Tab 3/Schedule 2 to the 2007 Audited Financial Statements.

Table 3

	CNPI 2007
Income Taxes per Audited Financial Statements	$ 1,725,000
Reconciling items:	
Future tax recovery(note 5 to AFS)	288,000
Capital cost allowance*	(50,981)
Amounts expensed for tax*	(7,420)
Apprenticeship credit*	(7,699)
Co-op credit*	(3,000)
Tax rate change*	(4,092)
CMT carryforward*	(14,699)
Miscellaneous other adjustments*	(9,548)
Income Taxes per Exhibit 4/Tab 3/Schedule 2	$ 1,915,561
Add capital taxes in operating expenses on AFS	$ 183,091
Total Taxes per Exhibit 4/Tab 3/Schedule 2	$ 2,098,652

*Adjustments between year end tax provision and preparation of corporate tax return.

c) **i**. The change in net earnings for CNPI from 2006 Actual to 2007 Actual is primarily due to a refund received from Niagara Mohawk (see Exhibit 1, Tab 3, Schedule 1, Appendix A, Note 18 to audited financial statements) and the 2007 early retirement window costs.

The change from 2007 Actual to 2008 Bridge Year is due to the repayment to Niagara Mohawk of the above referenced refund as ordered by FERC and the savings from the 2007 early retirement window.

The change from 2008 Bridge Year to 2009 Test Year is due to the increased distribution revenues associated with this cost of service rate application.

CNPI Earnings ($'000)			
2006 Actual	2007 Actual	2008 Bridge Year	2009 Test Year
2,141	3,529	348	3,928

ii. As discussed above, 2007 Actual earnings for transmission includes the Niagara Mohawk after-tax refund of approximately $1.6 million and 2008 Bridge Year includes the reversal of the same refund.

CNPI Transmission Earnings ($'000)			
2006 Actual	2007 Actual	2008 Bridge Year	2009 Test Year
1,348	3,179	(181)	1,802

The change in distribution earnings from 2006 Actual to 2007 Actual is primarily due to the 2007 early retirement window costs.

The change in distribution earnings from 2007 Actual to 2008 Bridge is due to the savings from the 2007 early retirement window.

The change in distribution earnings from 2008 Bridge Year to 2009 Test Year is due to the increased distribution revenues associated with this cost of service application requirement.

CNPI Distribution Earnings ($'000)			
2006 Actual	2007 Actual	2008 Bridge Year	2009 Test Year
793	350	529	2,126

iii. The explanation for changes in earnings for each distribution service area is similar to the total distribution earnings changes as described above. The cost of service applications provides variance analysis for changes in operating expenditures, capital expenditures, and revenue for each service territory. A detailed explanation of the change in operating expenditures for each service area includes the response to OEB-48, OEB-51 and OEB-54. The revenue requirement for each area is found in Exhibit 1/Tab 2/Schedule 4. In addition, the earnings for each service territory would be impacted by the allocation of interest expense amongst the business units.

In addition to earnings, changes in taxable income year over year are primarily a result of the difference between depreciation and CCA, and changes in reserve balances. From a tax planning perspective, CNPI continues in 2008 and 2009 to deduct for income tax purposes capitalized overhead, i.e., capitalized general expense. This deduction of capitalized overhead reduces income tax expense and therefore also reduces, revenue requirement. Where applicable, CNPI adjusted CCA taken to ensure no taxable income. The change in taxes year over year is a function of the tax rates.

INTERROGATORY # 61 - Deferral and Variance Accounts

CNPI – EOP specific interrogatories

References:
Exhibit 1, Tab 2, Schedule 1, page 12
Exhibit 5, Tab 1, Schedule 1, page 1
Exhibit 5, Tab 1, Schedule 2, page 1

- The 1st reference provides a brief statement about a deferral account related to seasonal customers.
- The 2nd reference provides an overview of deferral and variance accounts.
- The 3rd reference provides a calculation of balances by account.

a) In the 1st reference, the application states "CNPI - Gananoque is also seeking a deferral account mitigating rate effects on seasonal customers". In the 2nd reference, the application states "CNPI – Gananoque" is not requesting any new deferral accounts at this time". Please confirm which of the two statements is correct.

b) If the former is correct, please provide the following information.

- What is the regulatory precedent for this proposed deferral account?
- What is the justification for this account?
- What are the journal entries to be recorded?
- When does the applicant plan to ask for its disposition?
- How does the applicant plan to allocate this amount by rate class?
- If the costs or fees are not known, what would be the basis of the approval to record these amounts in a deferral account?
- What new or additional information is available that would improve the Board's ability to make a decision to approve the recording of these costs or fees in a deferral account?

c) Please provide the balance as of December 31, 2007 in each of the following accounts:

1508, 1518, 1525, 1548, 1570, 1571, 1572, 1574, 1582, 1590, 1592, 1595, and 2425

It is noted that the information provided in the table in the 3rd reference does not match previously reported information. Please provide any comments that might be helpful on the amounts provided.

d) Please provide a continuity schedule for the above accounts using the Excel spreadsheet attached. (Please note that forecasting principal transactions beyond December 31, 2007 and the interest on those transactions in columns AM – AP is optional.)

e) CNPI-EOP is requesting disposition of regulatory variance account 1508 only (2nd reference). Notwithstanding this, please provide rate riders that would dispose of the net balance of all of the accounts listed in part c), including details of how the individual balances would be allocated to customer classes and the length of time over which the rate rider would be charged or rebated.

RESPONSE:

a) The first reference stating "CNPI - Gananoque is also seeking a deferral account mitigating rate effects on seasonal customers" is an editing error and is incorrect. The second reference stating "CNPI - Gananoque is not requesting any new deferral accounts at this time" is correct.

b) N/A

c) The table below shows the December 31, 2007 balance (if any) in the requested accounts and the reconciliation with the balances previously filed in the RRR.

CNPI-Gananoque

OEB Account	1508	1590
Balance per 2007 RRR Filing	8,255	(16,175)
Adjustment re 2006 OEB fees	2,242	
Interest adjustment	1,183	
Balance Dec 31, 2007 per Rate Application	11,680	(16,176)

Note: There are no balances in the other accounts listed in Question A.

The information provided in the third reference does not match previously recorded information because it was calculated assuming the 2006 Board Approved regulatory asset balances were recorded in account 1590 at December 31, 2004. As of December 31, 2007 the balances agree with the "Board Staff Continuity Schedule".

d) In Attachment A to this response is the "OEB-61-BoardStaffContinuitySchedule". The "Adjustments during 2006-instructed by Board" are supported by the OEB Decision with Reasons, RP-2005-0020, EB-2006-0011. The "Adjustments during 2006-other" are either referred to in part c of this question or are reclassifications between CNPI - Fort Erie, CNPI - Port Colborne and CNPI - Gananoque.

e) Of the accounts listed in part c, CNPI-Gananoque only requires disposition of account 1508. Please see Exhibit 4/Tab 1/Schedule 4 for details.

ATTACHMENT A: INTERROGATORY # 61

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY Gananoque
Application ID NUMBER EB-2008-0222

Date

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

Account Description	Account Number	2005 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	$ 16,735					$ 16,735			$ -
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						$ -			$ -
Recovery of Regulatory Asset Balances	1590						$ -			$ -
Other Deferred Credits	2425						$ -			$ -
Sub-Totals		$ 16,735	$ -	$ -	$ -	$ -	$ 16,735	$ -	$ -	$ -
Disposition and Recovery of Regulatory Balances Control Account	1595	n/a								
Total		$ 16,735	$ -	$ -	$ -	$ -	$ 16,735	$ -	$ -	$ -

[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.

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Gananoque
Application ID NUMBER	EB-2008-0222
Date	

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	$ 16,735	$ 8,255	$ -		$ 2,242	$ (16,735)	$ 10,497	$ -	$ 2,723	$ (2,036)	$ 687
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	$ (38,000)	$ 236,839	$ (198,839)	$ -	$ -	$ 62,872	$ (62,872)	$ -
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	$ -						$ -	$ -			$ -
Recovery of Regulatory Asset Balances	1590	$ -		$ (73,324)			$ 121,781	$ 48,457	$ -	$ 2,579	$ 56,321	$ 58,900
Other Deferred Credits	2425	$ -						$ -	$ -			$ -
Sub-Totals		$ 16,735	$ 8,255	$ (73,324)	$ (38,000)	$ 239,081	$ (93,793)	$ 58,954	$ -	$ 68,174	$ (8,587)	$ 59,587
Disposition and Recovery of Regulatory Balances Control Account	1595						n/a					
Total		$ 16,735	$ 8,255	$ (73,324)	$ (38,000)	$ 239,081	$ (93,793)	$ 58,954	$ -	$ 68,174	$ (8,587)	$ 59,587

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Gananoque
Application ID NUMBER	EB-2008-0222
Date	

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	$ 10,497					$ 10,497	$ 687	$ 496	$ 1,183
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	$ -					$ -	$ -		$ -
Recovery of Regulatory Asset Balances	1590	$ 48,457		$ (123,409)			$ (74,952)	$ 58,900	$ (124)	$ 58,776
Other Deferred Credits	2425	$ -					$ -	$ -		$ -
Sub-Totals		$ 58,954	$ -	$ (123,409)	$ -	$ -	$ (64,455)	$ 59,587	$ 372	$ 59,959
Disposition and Recovery of Regulatory Balances Control Account	1595	$ -					$ -	$ -		$ -
Total		$ 58,954	$ -	$ (123,409)	$ -	$ -	$ (64,455)	$ 59,587	$ 372	$ 59,959

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Gananoque
Application ID NUMBER	EB-2008-0222
Date	

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			$ 11,680					$ 11,680
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			$ -					$ -
Recovery of Regulatory Asset Balances	1590			$ (16,176)					$ (16,176)
Other Deferred Credits	2425			$ -					$ -
Sub-Totals		$ -	$ -	$ (4,496)	$ -	$ -	$ -	$ -	$ (4,496)
Disposition and Recovery of Regulatory Balances Control Account	1595			$ -					$ -
Total		$ -	$ -	$ (4,496)	$ -	$ -	$ -	$ -	$ (4,496)

INTERROGATORY # 62 - Deferral and Variance Accounts

CNPI – Fort Erie specific interrogatories

Ref:
Exhibit 5, Tab 1, Schedule 1, page 1
Exhibit 5, Tab 1, Schedule 2, page 1

- The 1st reference provides an overview of deferral and variance accounts.
- The 2nd reference provides a calculation of balances by account.

a) Please provide the balance as of December 31, 2007 in each of the following accounts:
1508, 1518, 1525, 1548, 1570, 1571, 1572, 1574, 1582, 1590, 1592, 1595, and 2425.
It is noted that the information provided in the table in the 2nd reference does not match previously reported information. Please provide any comments that might be helpful on the amounts provided.

b) Please provide a continuity schedule for the above accounts using the Excel spreadsheet attached. (Please note that forecasting principal transactions beyond December 31, 2007 and the interest on those transactions in columns AM – AP is optional.)

c) CNPI-Fort Erie is requesting disposition of regulatory variance account 1508 only (1st reference). Notwithstanding this, please provide rate riders that would dispose of the net balance of all of the accounts listed in part a), including details of how the individual balances would be allocated to customer classes and the length of time over which the rate rider would be charged or rebated.

RESPONSE:

a) The table below shows the December 31, 2007 balance (if any) in the requested accounts and the reconciliation with the balances previously filed in the RRR.

CNPI-Fort Erie

OEB Account	1508	1572	1582	1590
Balance per 2007 RRR Filing	29,088	1,415,297	34,632	(231,544)
Adjustment re 2006 OEB fees	8,001			
Interest adjustment	4,181		5,613	
Balance Dec 31, 2007 per Rate Application	41,270	1,415,298	40,245	(231,544)

Note: There are no balances in the other accounts listed in Question A.

The information provided in the third reference does not match previously recorded information because it was calculated assuming the 2006 Board Approved regulatory asset balances were recorded in account 1590 at December 31, 2004. As of December 31, 2007 the balances agree with the "Board Staff Continuity Schedule".

b) In Attachment A to this response is the "OEB-62-BoardStaffContinuitySchedule". The "Adjustments during 2006-instructed by Board" are supported by the OEB Decision with Reasons, RP-2005-0020, EB-2006-0011. The "Adjustments during 2006-other" are either referred to in part c of this question or are reclassifications between CNPI - Fort Erie, CNPI - Port Colborne and CNPI - Gananoque.

c) In Attachment B to this response is the "OEB-62 regulatoryassetrecoveryworksheet" for disposition of accounts listed in part a).

ATTACHMENT A: INTERROGATORY # 62

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY CNPI-Fort Erie
Application ID NUMBER EB-2008-0223

Date

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

Account Description	Account Number	2005 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	$ 42,258					$ 42,258	$ -		$ -
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	$ (11,372)					$ (11,372)	$ -		$ -
Misc. Deferred Debits	1525	$ 20,728					$ 20,728	$ 3,005	$ 1,503	$ 4,508
Retail Cost Variance Account - STR	1548	$ 68,127					$ 68,127	$ -		$ -
Qualifying Transition Costs [4]	1570	$ 1,267,278	n/a	n/a			$ 1,267,278	$ 273,447	$ 91,878	$ 365,325
Pre-Market Opening Energy Variances Total [4]	1571		n/a	n/a			$ -			$ -
Extra-Ordinary Event Costs	1572	$ 221,718					$ 221,718	$ 45,009	$ 16,075	$ 61,084
Deferred Rate Impact Amounts	1574						$ -			$ -
RSVA -- One-time Wholesale Market Service	1582	$ 39,101	$ 17,072				$ 56,173	$ 1,782	$ 3,278	$ 5,060
Recovery of Regulatory Asset Balances	1590	$ (622,625)	$ 1,047,283	$ (113,954)			$ 310,704	$ (47,957)	$ 22,180	$ (25,777)
Other Deferred Credits	2425						$ -			$ -
Sub-Totals		$ 1,025,213	$ 1,064,355	$ (113,954)	$ -	$ -	$ 1,975,614	$ 275,286	$ 134,914	$ 410,200
Disposition and Recovery of Regulatory Balances Control Account	1595					n/a				
Total		$ 1,025,213	$ 1,064,355	$ (113,954)	$ -	$ -	$ 1,975,614	$ 275,286	$ 134,914	$ 410,200

[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.

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY CNPI-Fort Erie
Application ID NUMBER EB-2008-0223

Date

Account Description	Account Number	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
		2006										
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 42,258	$ 29,088			$ 8,001	$ (42,258)	$ 37,089	$ -	$ 7,731	$ (5,303)	$ 2,428
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	$ (11,372)					$ 11,372	$ -	$ -	$ (2,043)	$ 2,043	$ -
Misc. Deferred Debits	1525	$ 20,728					$ (20,728)	$ -	$ 4,508	$ 501	$ (5,009)	$ -
Retail Cost Variance Account - STR	1548	$ 68,127					$ (68,127)	$ -	$ -	$ 14,134	$ (14,134)	$ -
Qualifying Transition Costs [4]	1570	$ 1,267,278	n/a	n/a	$ (163,000)	$ (254,653)	$ (849,625)	$ -	$ 365,325	$ (99,866)	$ (265,459)	$ -
Pre-Market Opening Energy Variances Total [4]	1571	$ -	n/a	n/a				$ -	$ -			$ -
Extra-Ordinary Event Costs	1572	$ 221,718	$ 1,831,885	$ -	$ (60,539)		$ (161,179)	$ 1,831,885	$ 61,084	$ (2,698)	$ (48,299)	$ 10,087
Deferred Rate Impact Amounts	1574	$ -						$ -	$ -			$ -
RSVA -- One-time Wholesale Market Service	1582	$ 56,173	$ 8,624				$ (39,101)	$ 25,696	$ 5,060	$ 1,835	$ (2,673)	$ 4,222
Recovery of Regulatory Asset Balances	1590	$ 310,704	$ 719,172	$ (61,474)			$ (1,309,565)	$ (341,163)	$ (25,777)	$ 9,078	$ (51,749)	$ (68,448)
Other Deferred Credits	2425	$ -						$ -	$ -			$ -
Sub-Totals		$ 1,975,614	$ 2,588,769	$ (61,474)	$ (223,539)	$ (246,652)	$ (2,479,211)	$ 1,553,507	$ 410,200	$ (71,328)	$ (390,583)	$ (51,711)
Disposition and Recovery of Regulatory Balances Control Account	1595						**n/a**					
Total		$ 1,975,614	$ 2,588,769	$ (61,474)	$ (223,539)	$ (246,652)	$ (2,479,211)	$ 1,553,507	$ 410,200	$ (71,328)	$ (390,583)	$ (51,711)

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	CNPI-Fort Erie
Application ID NUMBER	EB-2008-0223
Date	

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	$ 37,089					$ 37,089	$ 2,428	$ 1,753	$ 4,181
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	$ 1,831,885	$ 554,146	$ (1,069,448)			$ 1,316,583	$ 10,087	$ 88,628	$ 98,715
Deferred Rate Impact Amounts	1574	$ -					$ -	$ -		$ -
RSVA -- One-time Wholesale Market Service	1582	$ 25,696	$ 8,936				$ 34,632	$ 4,222	$ 1,391	$ 5,613
Recovery of Regulatory Asset Balances	1590	$ (341,163)	$ 768,103	$ (577,981)			$ (151,041)	$ (68,448)	$ (12,055)	$ (80,503)
Other Deferred Credits	2425	$ -					$ -	$ -		$ -
Sub-Totals		$ 1,553,507	$ 1,331,185	$ (1,647,429)	$ -	$ -	$ 1,237,263	$ (51,711)	$ 79,717	$ 28,006
Disposition and Recovery of Regulatory Balances Control Account	1595	$ -					$ -	$ -		$ -
Total		$ 1,553,507	$ 1,331,185	$ (1,647,429)	$ -	$ -	$ 1,237,263	$ (51,711)	$ 79,717	$ 28,006

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	CNPI-Fort Erie
Application ID NUMBER	EB-2008-0223
Date	

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			$ 41,270					$ 41,270
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			$ -					$ -
Pre-Market Opening Energy Variances Total [4]	1571			$ -					$ -
Extra-Ordinary Event Costs	1572			$ 1,415,298					$ 1,415,298
Deferred Rate Impact Amounts	1574			$ -					$ -
RSVA -- One-time Wholesale Market Service	1582			$ 40,245					$ 40,245
Recovery of Regulatory Asset Balances	1590			$ (231,544)					$ (231,544)
Other Deferred Credits	2425			$ -					$ -
Sub-Totals		$ -	$ -	$ 1,265,269	$ -	$ -	$ -	$ -	$ 1,265,269
Disposition and Recovery of Regulatory Balances Control Account	1595			$ -					$ -
Total		$ -	$ -	$ 1,265,269	$ -	$ -	$ -	$ -	$ 1,265,269

ATTACHMENT B: INTERROGATORY # 62

SHEET 1 - December 31, 2007 Regulatory Assets

NAME OF UTILITY	Canadian Niagara Power Inc. Fort Erie	**LICENCE NUMBER**	EB-2008-0223
NAME OF CONTACT	Doug Bradbury	**DOCID NUMBER**	
E-mail Address	doug.bradbury@cnpower.com		
VERSION NUMBER		**PHONE NUMBER**	905-994-3634
Date		**(extension)**	

Account Description	**Account Number**	**Principal Amounts as of Dec-31 2007**	**Interest to Dec31-07**	**Interest Jan-1 to Dec31-08**	**Interest Jan1-09 to Apr30-09**				**Total Claim**
RSVA - Wholesale Market Service Charge	1580	$ -	$ -	$ -	$ -				$ -
RSVA - One-time Wholesale Market Service	1582	$ 34,632	$ 5,613	$ 1,160	$ 387				$ 41,791
RSVA - Retail Transmission Network Charge	1584	$ -	$ -	$ -	$ -				$ -
RSVA - Retail Transmission Connection Charge	1586	$ -	$ -	$ -	$ -				$ -
RSVA - Power	1588	$ -	$ -	$ -	$ -				$ -
Sub-Totals		$ 34,632	$ 5,613	$ 1,160	$ 387	$ -	$ -	$ -	$ 41,791
Other Regulatory Assets	1508	$ 37,089	$ 4,181	$ 1,242	$ 414				$ 42,927
Retail Cost Variance Account - Retail	1518	$ -	$ -	$ -	$ -				$ -
Retail Cost Variance Account - STR	1548	$ -	$ -	$ -	$ -				$ -
Misc. Deferred Debits - incl. Rebate Cheques	1525	$ -	$ -	$ -	$ -				$ -
Pre-Market Opening Energy Variances Total	1571								$ -
Extra-Ordinary Event Losses	1572	$ -	$ -	$ -	$ -				$ -
Deferred Rate Impact Amounts	1574								$ -
Other Deferred Credits	2425								$ -
Sub-Totals		$ 37,089	$ 4,181	$ 1,242	$ 414	$ -	$ -		$ 42,927
Totals per column		$ 71,721	$ 9,794	$ 2,403	$ 801	$ -	$ -	$ -	$ 84,718

Annual interest rate:	3.35%
Monthly interest rate:	0.2792%

SHEET 1 - December 31, 2007 Regulatory Assets

NAME OF UTILITY	Canadian Niagara Power Inc. Fort Erie	**LICENCE NUMBER**	EB-2008-0223
NAME OF CONTACT	Doug Bradbury	**DOCID NUMBER**	
E-mail Address	doug.bradbury@cnpower.com		
VERSION NUMBER		**PHONE NUMBER**	905-994-3634
Date		**(extension)**	

2009 Data By Class	kW	kWhs	Cust. Num.'s	Dx Revenue
RESIDENTIAL CLASS		115,322,011	14,315	$ 4,216,824
GENERAL SERVICE <50 KW CLASS		37,747,136	1,184	$ 1,082,987
GENERAL SERVICE >50 KW NON TIME OF USE	399,198	147,729,800	147	$ 3,086,026
GENERAL SERVICE >50 KW TIME OF USE				
INTERMEDIATE CLASS				
LARGE USER CLASS				
SMALL SCATTERED LOADS		349,768	119	$ 19,652
SENTINEL LIGHTS	2,423	797,374	961	$ 27,491
STREET LIGHTING	6,718	2,210,842	3,095	$ 59,168
Totals	408,339	304,156,931	19,821	$ 8,492,148

Allocators	kW	kWhs	Cust. Num.'s	Dx Revenue	Cust. #'s w/ Rebate Cheques	kWhs for Non TOU Customers
RESIDENTIAL CLASS	0.0%	37.9%	72.2%	49.7%		38.29%
GENERAL SERVICE <50 KW CLASS	0.0%	12.4%	6.0%	12.8%		12.53%
GENERAL SERVICE >50 KW NON TIME OF USE	97.8%	48.6%	0.7%	36.3%		49.06%
GENERAL SERVICE >50 KW TIME OF USE	0.0%	0.0%	0.0%	0.0%		
INTERMEDIATE CLASS	0.0%	0.0%	0.0%	0.0%		
LARGE USER CLASS	0.0%	0.0%	0.0%	0.0%		
SMALL SCATTERED LOADS	0.0%	0.1%	0.6%	0.2%		0.12%
SENTINEL LIGHTS	0.6%	0.3%	4.8%	0.3%		
STREET LIGHTING	1.6%	0.7%	15.6%	0.7%		
Totals	100%	100%	100%	100%	0%	100%

Sheet 2 - Rate Riders Calculation

NAME OF UTILITY	Canadian Niagara Power Inc. Fort Erie	**LICENCE NUMBER**	EB-2008-0223
NAME OF CONTACT	Doug Bradbury	**DOCID NUMBER**	
E-mail Address	doug.bradbury@cnpower.com		
VERSION NUMBER		**PHONE NUMBER**	905-994-3634
Date		**(extension)**	

Regulatory Asset Accounts:	**Amount**	**ALLOCATOR**	**Residential**	**GS < 50 KW**	**GS > 50 Non TOU**	**GS > 50 TOU**	**Intermediate**	**Large Users**	**Small Scattered Load**	**Sentinel Lighting**	**Street Lighting**	**Total**
WMSC - Account 1580	$ -	kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
One-Time WMSC - Account 1582	$ 41,791	kWh	$ 15,845	$ 5,186	$ 20,298	$ -	$ -	$ -	$ 48	$ 110	$ 304	$ 41,791
Network - Account 1584	$ -	kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Connection - Account 1586	$ -	kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Power - Account 1588	$ -	kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal - RSVA	$ 41,791		$ 15,845	$ 5,186	$ 20,298	$ -	$ -	$ -	$ 48	$ 110	$ 304	$ 41,791
Other Regulatory Assets - Account 1508	$ 42,927	Dx Revenue	$ 21,316	$ 5,474	$ 15,599	$ -	$ -	$ -	$ 99	$ 139	$ 299	$ 42,927
Retail Cost Variance Account - Acct 1518	$ -	# of Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retail Cost Variance Account (STR) Acct 1548	$ -	# of Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rebate Cheques - Acct 1525	$ -	# cust. w/ Rebate Cheq										$ -
Hydro One's Environmental Costs - Acct 1525	$ -	Dx Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Pre Market Opening Energy - Acct 1571	$ -	kWh for Non TOU Cust.	$ -	$ -	$ -				$ -			$ -
Extraordinary Event Losses - Acct 1572	$ -	# of Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Deferred Rate Impact Amounts - Acct 1574	$ -											$ -
Other Deferred Credits - Acct 2425	$ -											$ -
Transition Costs - Acct 1570	$ -	# of Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal - Non RSVA	$ 42,927		$ 21,316	$ 5,474	$ 15,599	$ -	$ -	$ -	$ 99	$ 139	$ 299	$ 42,927
Total to be Recovered	$ 84,718		$ 37,161	$ 10,661	$ 35,898	$ -	$ -	$ -	$ 147	$ 249	$ 603	$ 84,718
Balance to be collected or refunded in the next year	$ 84,718		$ 37,161	$ 10,661	$ 35,898	$ -	$ -	$ -	$ 147	$ 249	$ 603	$ 84,718
Balance to be collected or refunded per year	$ 84,718		$ 37,161	$ 10,661	$ 35,898	$ -	$ -	$ -	$ 147	$ 249	$ 603	$ 84,718

Class	**Residential**	**GS < 50 KW**	**GS > 50 Non TOU**	**GS > 50 TOU**	**Intermediate**	**Large Users**	**Scattered Load**	**Sentinel Lighting**	**Street Lighting**
Regulatory Asset Rate Riders	$ 0.0003	$ 0.0003	$ 0.0899				$ 0.0004	$ 0.1026	$ 0.0897
Billing Determinants	kWh	kWh	kW	kW	kW	kW	kWh	kW	kW

INTERROGATORY # 63 - Deferral and Variance Accounts

CNPI – Port Colborne specific interrogatories

References:
Exhibit 1, Tab 2, Schedule 1, page 12
Exhibit 5, Tab 1, Schedule 1, page 1
Exhibit 5, Tab 1, Schedule 2, page 1

- The 1st reference provides a brief statement about a deferral account related to seasonal customers.
- The 2nd reference provides an overview of deferral and variance accounts.
- The 3rd reference provides a calculation of balances by account.

a) In the 1st reference, the application states "CNPI – Port Colborne is also seeking a deferral account mitigating rate effects on seasonal customers". In the 2nd reference, the application states "CNPI – Port Colborne" is not requesting any new deferral accounts at this time". Please confirm which of the two statements is correct.

b) If the former is correct, please provide the following information.

- What is the regulatory precedent for this proposed deferral account?
- What is the justification for this account?
- What are the journal entries to be recorded?
- When does the applicant plan to ask for its disposition?
- How does the applicant plan to allocate this amount by rate class?
- If the costs or fees are not known, what would be the basis of the approval to record these amounts in a deferral account?
- What new or additional information is available that would improve the Board's ability to make a decision to approve the recording of these costs or fees in a deferral account?

c) Please provide the balance as of December 31, 2007 in each of the following accounts:

1508, 1518, 1525, 1548, 1570, 1571, 1572, 1574, 1582, 1590, 1592, 1595, and 2425.

It is noted that the information provided in the table in the 3rd reference does not match previously reported information. Please provide any comments that might be helpful on the amounts provided.

d) Please provide a continuity schedule for the above accounts using the Excel spreadsheet attached. (Please note that forecasting principal transactions beyond December 31, 2007 and the interest on those transactions in columns AM – AP is optional.)

e) CNPI-Port Colborne is requesting disposition of regulatory variance account 1508 only (2nd reference). Notwithstanding this, please provide rate riders that would dispose of the net balance of all of the accounts listed in part c), including details of how the individual balances would be allocated to customer classes and the length of time over which the rate rider would be charged or rebated.

RESPONSE:

a) The first reference stating "CNPI-Port Colborne is also seeking a deferral account mitigating rate effects on seasonal customers" is an editing error and is incorrect. The second reference stating "CNPI-Port Colborne is not requesting any new deferral accounts at this time" is correct.

b) N/A

c) The table below shows the December 31, 2007 balance (if any) in the requested accounts and the reconciliation with the balances previously filed in the RRR.

CNPI-Port Colborne

OEB Account	1508	1572	1582	1590
Balance per 2007 RRR Filing	17,904	147,115	23,520	(84,336)
Adjustment re 2006 OEB fees	4,489			
Interest adjustment	2,525		2,765	
Balance Dec 31, 2007 per Rate Application	24,918	147,115	26,285	(84,335)

Note: There are no balances in the other accounts listed in Question A.

The information provided in the third reference does not match previously recorded information because it was calculated assuming the 2006 Board Approved regulatory asset balances were recorded in account 1590 at December 31, 2004. As of December 31, 2007 the balances agree with the "Board Staff Continuity Schedule".

d) In Attachment A to this response is the "OEB-63-BoardStaffContinuitySchedule". The "Adjustments during 2006-instructed by Board" are supported by the OEB Decision with Reasons, RP-2005-0020, EB-2006-0011. The "Adjustments during 2006-other" are either referred to in part c of this question or are reclassifications between CNPI - Fort Erie, CNPI - Port Colborne and CNPI - Gananoque.

e) In Attachment B to this response see the "OEB-63-regulatoryassetrecoveryworksheet" for disposition of accounts listed in part c).

ATTACHMENT A: INTERROGATORY # 63

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY CNPI-Port Colborne
Application ID NUMBER EB-2008-0224

Date

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	$ 18,171	$ 17,904				$ 36,075		$ 3,651	$ 3,651
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	$ (8,710)					$ (8,710)			$ -
Misc. Deferred Debits	1525	$ 13,819					$ 13,819	$ 2,004	$ 1,002	$ 3,006
Retail Cost Variance Account - STR	1548	$ 38,062					$ 38,062			$ -
Qualifying Transition Costs [4]	1570	$ 994,968	n/a	n/a			$ 994,968	$ 226,483	$ 72,135	$ 298,618
Pre-Market Opening Energy Variances Total [4]	1571	$ 396,356	n/a	n/a			$ 396,356	$ 89,976	$ 28,736	$ 118,712
Extra-Ordinary Event Costs	1572	$ 147,811					$ 147,811	$ 30,006	$ 10,716	$ 40,722
Deferred Rate Impact Amounts	1574						$ -			$ -
RSVA -- One-time Wholesale Market Service	1582	$ 24,782	$ 10,724				$ 35,506	$ 2,815	$ 2,076	$ 4,891
Recovery of Regulatory Asset Balances	1590	$ (505,259)		$ (265,161)			$ (770,420)	$ (21,870)	$ (27,986)	$ (49,856)
Other Deferred Credits	2425						$ -			$ -
Sub-Totals		$ 1,120,000	$ 28,628	$ (265,161)	$ -	$ -	$ 883,467	$ 329,414	$ 90,330	$ 419,744
Disposition and Recovery of Regulatory Balances Control Account	1595					**n/a**				
Total		$ 1,120,000	$ 28,628	$ (265,161)	$ -	$ -	$ 883,467	$ 329,414	$ 90,330	$ 419,744

[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.

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY CNPI-Port Colborne
Application ID NUMBER EB-2008-0224

Date

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	$ 36,075	$ -			$ 4,489	$ (18,171)	$ 22,393	$ 3,651	$ 8	$ (2,193)	$ 1,466
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	$ (8,710)					$ 8,710	$ -	$ -	$ (1,711)	$ 1,711	$ -
Misc. Deferred Debits	1525	$ 13,819					$ (13,819)	$ -	$ 3,006	$ 334	$ (3,340)	$ -
Retail Cost Variance Account - STR	1548	$ 38,062					$ (38,062)	$ -	$ -	$ 7,182	$ (7,182)	$ -
Qualifying Transition Costs [4]	1570	$ 994,968	n/a	n/a	$ (199,000)	$ 17,814	$ (813,782)	$ -	$ 298,618	$ (35,596)	$ (263,022)	$ -
Pre-Market Opening Energy Variances Total [4]	1571	$ 396,356	n/a	n/a	$ -		$ (396,356)	$ -	$ 118,712	$ 9,579	$ (128,291)	$ -
Extra-Ordinary Event Costs	1572	$ 147,811	$ 240,934		$ (40,359)	$ -	$ (107,452)	$ 240,934	$ 40,722	$ (7,086)	$ (32,200)	$ 1,436
Deferred Rate Impact Amounts	1574	$ -						$ -	$ -			$ -
RSVA -- One-time Wholesale Market Service	1582	$ 35,506	$ 6,132				$ (24,782)	$ 16,856	$ 4,891	$ 1,166	$ (4,223)	$ 1,834
Recovery of Regulatory Asset Balances	1590	$ (770,420)	$ 331,015	$ (201,784)			$ 104,794	$ (536,395)	$ (49,856)	$ (31,133)	$ 215,872	$ 134,883
Other Deferred Credits	2425	$ -						$ -	$ -			$ -
Sub-Totals		$ 883,467	$ 578,081	$ (201,784)	$ (239,359)	$ 22,303	$ (1,298,920)	$ (256,212)	$ 419,744	$ (57,257)	$ (222,868)	$ 139,619
Disposition and Recovery of Regulatory Balances Control Account	1595						n/a					
Total		$ 883,467	$ 578,081	$ (201,784)	$ (239,359)	$ 22,303	$ (1,298,920)	$ (256,212)	$ 419,744	$ (57,257)	$ (222,868)	$ 139,619

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY CNPI-Port Colborne
Application ID NUMBER EB-2008-0224

Date

Account Description	Account Number	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
		2007								
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 22,393					$ 22,393	$ 1,466	$ 1,059	$ 2,525
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	$ 240,934	$ 2,388	$ (108,592)			$ 134,730	$ 1,436	$ 10,949	$ 12,385
Deferred Rate Impact Amounts	1574	$ -					$ -	$ -		$ -
RSVA -- One-time Wholesale Market Service	1582	$ 16,856	$ 6,664				$ 23,520	$ 1,834	$ 931	$ 2,765
Recovery of Regulatory Asset Balances	1590	$ (536,395)	$ 469,692	$ (134,086)			$ (200,789)	$ 134,883	$ (18,429)	$ 116,454
Other Deferred Credits	2425	$ -					$ -	$ -		$ -
Sub-Totals		$ (256,212)	$ 478,744	$ (242,678)	$ -	$ -	$ (20,146)	$ 139,619	$ (5,490)	$ 134,129
Disposition and Recovery of Regulatory Balances Control Account	1595	$ -					$ -	$ -		$ -
Total		$ (256,212)	$ 478,744	$ (242,678)	$ -	$ -	$ (20,146)	$ 139,619	$ (5,490)	$ 134,129

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	CNPI-Port Colborne
Application ID NUMBER	EB-2008-0224
Date	

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			$ 24,918					$ 24,918
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			$ 147,115					$ 147,115
Deferred Rate Impact Amounts		1574			$ -					$ -
RSVA -- One-time Wholesale Market Service		1582			$ 26,285					$ 26,285
Recovery of Regulatory Asset Balances		1590			$ (84,335)					$ (84,335)
Other Deferred Credits		2425			$ -					$ -
	Sub-Totals		$ -	$ -	$ 113,983	$ -	$ -	$ -	$ -	$ 113,983
Disposition and Recovery of Regulatory Balances Control Account		1595			$ -					$ -
	Total		$ -	$ -	$ 113,983	$ -	$ -	$ -	$ -	$ 113,983

ATTACHMENT B: INTERROGATORY # 63

SHEET 1 - December 31, 2007 Regulatory Assets

NAME OF UTILITY	Canadian Niagara Power Inc. Port Colborne	**LICENCE NUMBER**	EB-2008-0224
NAME OF CONTACT	Doug Bradbury	**DOCID NUMBER**	
E-mail Address	doug.bradbury@cnpower.com		
VERSION NUMBER		**PHONE NUMBER**	905-994-3634
Date		**(extension)**	

Account Description	Account Number	Principal Amounts as of Dec-31 2007	Interest to Dec31-07	Interest Jan-1 to Dec31-08	Interest Jan1-09 to Apr30-09				Total Claim
RSVA - Wholesale Market Service Charge	1580	$ -	$ -	$ -	$ -				$ -
RSVA - One-time Wholesale Market Service	1582	$ 23,520	$ 2,765	$ 788	$ 263				$ 27,336
RSVA - Retail Transmission Network Charge	1584	$ -	$ -	$ -	$ -				$ -
RSVA - Retail Transmission Connection Charge	1586	$ -	$ -	$ -	$ -				$ -
RSVA - Power	1588	$ -	$ -	$ -	$ -				$ -
Sub-Totals		$ 23,520	$ 2,765	$ 788	$ 263	$ -	$ -	$ -	$ 27,336
Other Regulatory Assets	1508	$ 22,393	$ 2,525	$ 750	$ 250				$ 25,918
Retail Cost Variance Account - Retail	1518	$ -	$ -	$ -	$ -				$ -
Retail Cost Variance Account - STR	1548	$ -	$ -	$ -	$ -				$ -
Misc. Deferred Debits - incl. Rebate Cheques	1525	$ -	$ -	$ -	$ -				$ -
Pre-Market Opening Energy Variances Total	1571								$ -
Extra-Ordinary Event Losses	1572	$ -	$ -	$ -	$ -				$ -
Deferred Rate Impact Amounts	1574								$ -
Other Deferred Credits	2425								$ -
Sub-Totals		$ 22,393	$ 2,525	$ 750	$ 250	$ -	$ -		$ 25,918
Totals per column		$ 45,913	$ 5,290	$ 1,538	$ 513	$ -	$ -	$ -	$ 53,254

Annual interest rate:	3.35%
Monthly interest rate:	0.2792%

SHEET 1 - December 31, 2007 Regulatory Assets

NAME OF UTILITY	Canadian Niagara Power Inc. Port Colborne	**LICENCE NUMBER**	EB-2008-0224
NAME OF CONTACT	Doug Bradbury	**DOCID NUMBER**	
E-mail Address	doug.bradbury@cnpower.com		
VERSION NUMBER		**PHONE NUMBER**	905-994-3634
Date		**(extension)**	

2009 Data By Class	kW	kWhs	Cust. Num.'s	Dx Revenue
RESIDENTIAL CLASS		64,972,406	8,155	$ 2,524,212
GENERAL SERVICE <50 KW CLASS		25,831,151	934	$ 584,250
GENERAL SERVICE >50 KW NON TIME OF USE	377,959	99,392,250	81	$ 1,507,152
GENERAL SERVICE >50 KW TIME OF USE				
INTERMEDIATE CLASS				
LARGE USER CLASS				
SMALL SCATTERED LOADS		581,173	19	$ 12,546
SENTINEL LIGHTS	38	12,725	36	$ 1,160
STREET LIGHTING	5,433	1,792,552	1,985	$ 48,162
Totals	383,430	192,582,257	11,210	$ 4,677,482

Allocators	kW	kWhs	Cust. Num.'s	Dx Revenue	Cust. #'s w/ Rebate Cheques	kWhs for Non TOU Customers
RESIDENTIAL CLASS	0.0%	33.7%	72.7%	54.0%		34.06%
GENERAL SERVICE <50 KW CLASS	0.0%	13.4%	8.3%	12.5%		13.54%
GENERAL SERVICE >50 KW NON TIME OF USE	98.6%	51.6%	0.7%	32.2%		52.10%
GENERAL SERVICE >50 KW TIME OF USE	0.0%	0.0%	0.0%	0.0%		
INTERMEDIATE CLASS	0.0%	0.0%	0.0%	0.0%		
LARGE USER CLASS	0.0%	0.0%	0.0%	0.0%		
SMALL SCATTERED LOADS	0.0%	0.3%	0.2%	0.3%		0.30%
SENTINEL LIGHTS	0.0%	0.0%	0.3%	0.0%		
STREET LIGHTING	1.4%	0.9%	17.7%	1.0%		
Totals	100%	100%	100%	100%	0%	100%

Sheet 2 - Rate Riders Calculation

NAME OF UTILITY	Canadian Niagara Power Inc. Port Colborne	**LICENCE NUMBER**	EB-2008-0224
NAME OF CONTACT	Doug Bradbury	**DOCID NUMBER**	
E-mail Address	doug.bradbury@cnpower.com		
VERSION NUMBER		**PHONE NUMBER**	905-994-3634
Date		**(extension)**	

Regulatory Asset Accounts:	Amount	ALLOCATOR	Residential	GS < 50 KW	GS > 50 Non TOU	GS > 50 TOU	Intermediate	Large Users	Small Scattered Load	Sentinel Lighting	Street Lighting	Total
WMSC - Account 1580	$ -	kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
One-Time WMSC - Account 1582	$ 27,336	kWh	$ 9,222	$ 3,667	$ 14,108	$ -	$ -	$ -	$ 82	$ 2	$ 254	$ 27,336
Network - Account 1584	$ -	kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Connection - Account 1586	$ -	kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Power - Account 1588	$ -	kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal - RSVA	$ 27,336		$ 9,222	$ 3,667	$ 14,108	$ -	$ -	$ -	$ 82	$ 2	$ 254	$ 27,336
Other Regulatory Assets - Account 1508	$ 25,918	Dx Revenue	$ 13,987	$ 3,237	$ 8,351	$ -	$ -	$ -	$ 70	$ 6	$ 267	$ 25,918
Retail Cost Variance Account - Acct 1518	$ -	# of Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retail Cost Variance Account (STR) Acct 1548	$ -	# of Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rebate Cheques - Acct 1525	$ -	# cust. w/ Rebate Cheq										$ -
Hydro One's Environmental Costs - Acct 1525	$ -	Dx Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Pre Market Opening Energy - Acct 1571	$ -	kWh for Non TOU Cust.	$ -	$ -	$ -				$ -			$ -
Extraordinary Event Losses - Acct 1572	$ -	# of Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Deferred Rate Impact Amounts - Acct 1574	$ -											$ -
Other Deferred Credits - Acct 2425	$ -											$ -
Transition Costs - Acct 1570	$ -	# of Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal - Non RSVA	$ 25,918		$ 13,987	$ 3,237	$ 8,351	$ -	$ -	$ -	$ 70	$ 6	$ 267	$ 25,918
Total to be Recovered	$ 53,254		$ 23,209	$ 6,904	$ 22,459	$ -	$ -	$ -	$ 152	$ 8	$ 521	$ 53,254
Balance to be collected or refunded in the next year	$ 53,254		$ 23,209	$ 6,904	$ 22,459	$ -	$ -	$ -	$ 152	$ 8	$ 521	$ 53,254
Balance to be collected or refunded per year	$ 53,254		$ 23,209	$ 6,904	$ 22,459	$ -	$ -	$ -	$ 152	$ 8	$ 521	$ 53,254

Class	Residential	GS < 50 KW	GS > 50 Non TOU	GS > 50 TOU	Intermediate	Large Users	Scattered Load	Sentinel Lighting	Street Lighting
Regulatory Asset Rate Riders	$ 0.0004	$ 0.0003	$ 0.0594				$ 0.0003	$ 0.2167	$ 0.0960
Billing Determinants	kWh	kWh	kW	kW	kW	kW	kWh	kW	kW

INTERROGATORY # 64 - Specific Service Charges:

Interrogatory common to all three applications

Reference: Exhibit 1, Tab 1, Schedule 2, Appendix A

The reference provides a list of specific service charges proposed for 2009.

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

RESPONSE:

CNPI confirms that the proposed specific service charges as shown in Exhibit 1, Tab 1, Schedule 2, Appendix A are identical to the standard charges in Schedule 11-3 of the 2006 EDR Handbook.

INTERROGATORY # 65 – Cost Allocation & Rate Design

CNPI – EOP specific interrogatories

Ref:
Exhibit 8, Tab 1, Schedule 2, Appendix A, Sheet O1
Exhibit 8, Tab 1, Schedule 2, Appendix A, Sheet O2
EB-2008-0223/Exhibit 10, Tab 1, Schedule 3, page 6
EB-2008-0223/Exhibit 10, Tab 1, Schedule 3, pages 14 to 22
EB-2008-0223/Exhibit 10, Tab 1, Schedule 7, pages 2 to 4

- The 1st reference provides Sheet O1 from the Cost Allocation Informational Filing (Run 2).
- The 2nd reference provides Sheet O2 from the Cost Allocation Informational Filing (Run 2).
- The 3rd reference provides harmonized base revenue requirement.
- The 4th reference provides revenue-to-cost ratios based on harmonized rates across CNPI – Fort Erie and CNPI – EOP.
- The 5th reference provides bill impact calculations based on harmonized rates between CNPI – Fort Erie and CNPI – EOP.

a) For completeness of the evidence relating to CNPI – EOP, please file the equivalent of Rate Harmonization as presented in Exhibit 10 of the CNPI – Fort Erie application as part of the CNPI – EOP application.
b) Please confirm that the harmonized base revenue requirement of $11,476,276 provided in the 3rd reference represents the combined revenue requirement of CNPI – Fort Erie and CNPI – EOP. Further please confirm that of this amount, $9,252,464 is attributable to the former and $2,223,812 to the latter.
c) Please provide a breakdown by rate class of CNPI – EOP's component of the harmonized base revenue requirement of $11,476,276 referred to above.
d) With respect to the USL rate class:
    - The application acknowledges in the 4th reference the need to gradually move the revenue-to-cost ratio towards 100%. However in actual fact the ratio has changed from 65.94% in the Cost Allocation Informational Filing (1st reference) to 44.69% in the proposal for 2009 (4th reference). Please explain the reason for the movement of the ratio to a value away from rather than towards 100%.
    - Please explain the reason for the 21% increase in the distribution component of the monthly bill from $53.79 for 2008 to $44.42 for 2009 (5th reference) when the revenue-to-cost ratio has declined as stated above.
e) With respect to the Sentinel Lighting rate class, as shown in the 5th reference, the percentage increase in the monthly service charge from 2008 to 2009 ($1.78 to $2.94, i.e. 65%) exceeds the percentage increase in the volumetric rate ($2.6201/kW to $3.3822/kW, i.e. 29%). Please provide a calculation of rates where the percentage increase in the monthly service charge is the same as the percentage increase in the volumetric rate and comment on how the resulting

monthly service charge compares with the Customer Unit Cost per month – Minimum System.

RESPONSE:

a) See Attachment A to this response.

b) CNPI confirms that the harmonized base revenue requirement of $11,476,276 provided in the 3rd reference represents the combined revenue requirement of CNPI – Fort Erie and CNPI – EOP. Further CNPI confirms that of this amount, $9,252,464 is attributable to the CNPI – Fort Erie and $2,223,812 to CNPI – Eastern Ontario Power.

c) The illustration below calculates the breakdown by rate class of CNPI – EOP's and CNPI – Fort Erie's component of the harmonized base revenue requirement of $11,596.262 (the base revenue requirement of $11,476,276 plus transformer ownership credit of $119,986). The transformer ownership was included for consistency with the rate design models submitted.

As seen from the chart, one of the effects of harmonizing electricity distribution rates is to shift some portion of the base revenue requirement. As discussed in Exhibit 10, Tab 1, Schedule 1 page 1 of the CNPI – Fort Erie Application, CNPI has determined that approximately $129,000 of the CNPI – EOP base revenue requirement (with transformer allowance) has shifted to CNPI – Fort Erie.

Harmonized Electricity Distribution Rates
Reconciliation of 2009 Revenue Requirement and 2009 Proposed Electricity Distribution Rates

		2009 Volumes		Proposed Rates		2009 Revenue		
Customer Class	No. of Customers / Connections	kWh	kW	Monthly Service Charge	Volumetric Charge	Total Class Distribution Revenue	2009 Base Revenue Requirement	Percentage by Class
Residential	17,369	144,908,264		17.69	0.0149	5,846,118	5,852,901	50.4%
General Service Less Than 50 kW	1,596	51,795,147		21.07	0.0228	1,584,336	1,581,936	13.7%
General Service 50 to 4,999 kW	180	166,344,327	457,378	147.84	8.0290	3,991,620	3,991,622	34.4%
Unmetered Scattered Load	28	444,370		36.39	0.0214	21,737	21,759	0.2%
Sentinel Lighting	1,051	877,992	2,664	2.94	3.3256	45,939	45,905	0.4%
Street Lighting	3,684	2,766,461	8,380	1.69	3.2908	102,289	102,139	0.9%
	23,907	367,136,561	468,422			11,592,038	11,596,262	100.0%

Fort Erie				Proposed Rates				
Customer Class	No. of Customers / Connections	kWh	kW	Monthly Service Charge	Volumetric Charge	Total Class Distribution Revenue	2009 Base Revenue Requirement	Percentage by Class
Residential	14,255	114,834,621		17.69	0.0150	4,748,465	4,906,212	50.0%
General Service Less Than 50 kW	1,181	37,635,552		21.07	0.0228	1,156,568	1,228,727	12.2%
General Service 50 to 4,999 kW	146	146,222,353	395,124	147.84	8.0620	3,443,619	3,077,251	36.3%
Unmetered Scattered Load	20	345,359		36.39	0.0217	16,228	24,334	0.2%
Sentinel Lighting	961	797,374	2,423	2.94	3.3290	41,970	42,006	0.4%
Street Lighting	3,088	2,205,484	6,702	1.69	3.3000	84,730	85,030	0.9%
	19,747	302,040,745	404,249			9,491,579	9,363,560	100.0%

Gananoque				Proposed Rates				
Customer Class	No. of Customers / Connections	kWh	kW	Monthly Service Charge	Volumetric Charge	Total Class Distribution Revenue	2009 Base Revenue Requirement	Percentage by Class
Residential	3,114	29,538,825		17.69	0.0150	1,104,122	1,095,227	52.5%
General Service Less Than 50 kW	415	13,980,635		21.07	0.0228	423,687	402,510	20.1%
General Service 50 to 4,999 kW	35	19,868,966	60,385	147.84	8.0620	548,028	702,719	26.1%
Unmetered Scattered Load	8	94,602		36.39	0.0217	5,546	4,937	0.3%
Sentinel Lighting	90	79,732	239	2.94	3.3290	3,969	4,136	0.2%
Street Lighting	597	553,300	1,655	1.69	3.3000	17,560	23,172	0.8%
	4,258	64,116,059	62,279			2,102,913	2,232,702	100.0%

d) Part I

The Cost Allocation Informational Filing for CNPI – Eastern Ontario Power indicated a 65.94% revenue to cost ratio for the USL class. The harmonized Cost Allocation Informational Filing indicated a 57.76% revenue to cost ratio for the USL class. In CNPI harmonized rate design, Exhibit 10, the proposed cost to revenue ratio is 44.69%; the ratio was proposed in order to limit the combined USL class for Fort Erie and Gananoque to a 10% total bill impact in Gananoque. If the cost to revenue ratio was maintained at 65.94%, the total bill impact for the average USL customer would have been 35.4%.

Part II

The distribution component of the 2008 approved rates for the USL customer described in the question is $44.42, in the CNPI – Eastern Ontario Application the proposed rates would increase this same charge to $48.28; an increase of 8.7%. In the proposed harmonized rates with CNPI – Fort Erie the amount would increase to $53.79, a 21% increase. This increase is a result of converting the billing parameter in CNPI – Fort Erie to a per customer basis from the current per connection format. The per customer billing format reduces the denominator in the monthly service charge determinant.

As discussed in the Application, the common USL customer has several connections and therefore the streamlined billing format will not result in increased charges.

e) Changing the fixed – variable split from the proposed 80.7% fixed and 19.3% variable to 76.53% fixed and 23.47% variable will yield a monthly service charge of $2.79 and a volumetric charge of $4.1008. Both charges are 57% increases over the 2008 approved rates. This change in fixed/variable split increases the total bill impact from 8.4% to 10.6% for a sentinel customer in Gananoque.

The rate of $2.79 remains below the upper bound from the Cost Allocation Informational Filing.

ATTACHMENT A: OEB INTERROGATORY # 65

RATE HARMONIZATION

In this Application, CNPI is proposing to harmonize the distribution rates of the Fort Erie and Gananoque service territories. The Port Colborne service territory has been intentionally omitted from the harmonization in this Application due to restrictions related to the lease agreement with Port Colborne Hydro Inc. and the Board's approval of that lease.

Currently, CNPI operates three distribution territories, Fort Erie, Port Colborne and Gananoque, as well as a transmission operation in Fort Erie. CNPI operates primarily from a single location, Fort Erie, with a single work force and allocates assets and services to each of these business units. This segregation of business units requires duplicated efforts related to financial and regulatory reporting, regulatory compliance and rate setting. CNPI proposes, with this Application, to begin a process to harmonize its distribution operations as a single entity thus eliminating this duplication and reduce regulatory burdens for CNPI and the Regulator.

The approach taken in this electricity distribution rate harmonization proposal is to blend the two revenue requirements that had been developed separately, both in this Application, EB-2008-0223 and the Eastern Ontario Power Application, EB-2008-0222 and combine them as one. While this approach will inevitably result in some revenue shifting between the two service territories, CNPI has considered this variable in its rate design, Exhibit 10, Tab 1, Schedule 3.

The final rate design in this Application has yielded a revenue shift of approximately $129,000. The amount is approximated due to variances introduced by rounding the distribution rates for fixed and variable components to two and four decimal places respectively. The revenue shift has been calculated by applying the customer and load forecasts of each service territory to the harmonized rates and then comparing the class and total revenue recoveries to the original service revenue requirements. The variance for the respective service territories is measured as the revenue shift. In this case, the $129,000 shift is from Fort Erie to Gananoque and accounts for approximately 1.1%% of the combine Base revenue Requirement net of Low Voltage charges.

The table attached shows the derivation of the revenue shift.

The recovery of Low Voltage charges have been excluded from the analysis. Low Voltage charges from Hydro One apply only in Gananoque and not in Fort Erie, therefore these charges will be in the form of a rate adder to the volumetric distribution charge in Gananoque.

In similar fashion, the respective distribution loss factor and retail transmission tariffs will also, for the purpose of this Application, remain specific to each of the two service territories.

Cost allocation, discussed in Exhibit 10, Tab 1, Schedule 2 has been projected by combining the individual Coat Allocation Informational Filings submitted by CNPI on January 18, 2007. The Cost Allocation is provided in Exhibit 10, Tab 1, Schedule 2 Appendix A of this Application and an electronic copy of the Cost Allocation Model accompanies this Application.

Rate design, proposed rate schedules and bill impacts follow in the subsequent schedules of this Exhibit.

Harmonized Electricity Distribution Rates
Reconciliation of 2009 Revenue Requirement and 2009 Proposed Electricity Distribution Rates

		2009 Volumes		Proposed 2009 Rates		2009 Revenue			
Customer Class	No. of Customers / Connections	kWh	kW	Monthly Service Charge	Volumetric Charge	Monthly Service Charge	Volumetric Charge	Total Class Distribution Revenue	2009 Base Revenue Requirement
Residential	17,369	144,373,446		17.69	0.0150	3,686,985	2,165,602	5,852,587	5,852,901
General Service Less Than 50 kW	1,596	51,616,187		21.07	0.0228	403,406	1,176,849	1,580,255	1,581,936
General Service 50 to 4,999 kW	180	166,091,320	455,509	147.84	8.0620	319,334	3,672,313	3,991,647	3,991,622
Unmetered Scattered Load	28	439,961		36.39	0.0217	12,227	9,547	21,774	21,759
Sentinel Lighting	1,051	877,106	2,661	2.94	3.3290	37,079	8,860	45,939	45,905
Street Lighting	3,684	2,758,784	8,357	1.69	3.3000	74,712	27,578	102,289	102,139
	23,907	366,156,804	466,527			4,533,744	7,060,748	11,594,492	11,596,262

Difference due to rounding (1,770)

Fort Erie

		2009 Volumes		Proposed 2009 Rates					
Customer Class	No. of Customers / Connections	kWh	kW	Monthly Service Charge	Volumetric Charge	Monthly Service Charge	Volumetric Charge	Total Class Distribution Revenue	2009 Base Revenue Requirement
Residential	14,255	114,834,621		17.69	0.0150	3,025,945	1,722,519	4,748,465	4,906,212
General Service Less Than 50 kW	1,181	37,635,552		21.07	0.0228	298,478	858,091	1,156,568	1,228,727
General Service 50 to 4,999 kW	146	146,222,353	395,124	147.84	8.0620	258,129	3,185,490	3,443,619	3,077,251
Unmetered Scattered Load	20	345,359		36.39	0.0217	8,734	7,494	16,228	24,334
Sentinel Lighting	961	797,374	2,423	2.94	3.3290	33,904	8,066	41,970	42,006
Street Lighting	3,088	2,205,484	6,702	1.69	3.3000	62,615	22,115	84,730	85,030
	19,747	302,040,745	404,249			3,687,804	5,803,775	9,491,579	9,363,560

Revenue Shift 128,019

Gananoque

		2009 Volumes		Proposed 2009 Rates					
Customer Class	No. of Customers / Connections	kWh	kW	Monthly Service Charge	Volumetric Charge	Monthly Service Charge	Volumetric Charge	Total Class Distribution Revenue	2009 Base Revenue Requirement
Residential	3,114	29,538,825		17.69	0.0150	661,040	443,082	1,104,122	1,095,227
General Service Less Than 50 kW	415	13,980,635		21.07	0.0228	104,929	318,758	423,687	402,510
General Service 50 to 4,999 kW	35	19,868,966	60,385	147.84	8.0620	61,206	486,823	548,028	702,719
Unmetered Scattered Load	8	94,602		36.39	0.0217	3,493	2,053	5,546	4,937
Sentinel Lighting	90	79,732	239	2.94	3.3290	3,175	794	3,969	4,136
Street Lighting	597	553,300	1,655	1.69	3.3000	12,097	5,463	17,560	23,172
	4,258	64,116,059	62,279			845,940	1,256,973	2,102,913	2,232,702

Revenue Shift (129,789)

COST ALLOCATION INFORMATION FILING

On September 29, 2006, the Board issued directions related to Cost Allocation Methodology for Electricity Distributors. On November 15, 2006, the Board issued the Cost Allocation Filing Guidelines, a Cost Allocation Model and User Instructions for the model. On January 18, 2007, CNPI – Fort Erie and CNPI – Eastern Ontario Power submitted its Cost Allocation Informational Filing, EB-2005-0344 and EB-2005-0344 respectively.

CNPI proposes that the results of these filing are still the most appropriate cost allocation to be used for rate design in the 2009 EDR. This cost allocation process is the collective understanding of many of the electricity distribution companies, intervenor community, industry experts and Board staff, all of whom are very familiar with the Ontario electricity distribution sector. CNPI uses a similar operating framework with the same operating and administration regimes in each of its service territories. The operating framework and customer profile at CNPI has not changed significantly since this Cost Allocation Informational Filings and any attempt to update it with more recent metrics should not significantly alter the outcome.

COST ALLOCATION – SUMMARY OF RESULTS

A primary result of the Cost Allocation Study is the Revenue-to-Cost Ratios for the customer classes. The Revenue-to-Cost Ratio is the ratio of actual or proposed revenue from a customer class to the portion of revenue requirement allocated to that class. A ratio less than unity suggests that the customer class is under-contributing and its service is being subsidized by the other customer classes. A ratio greater than unity suggests that the customer class is over-contributing to the revenue requirement and is therefore subsidizing another customer class.

The following table summarizes the Revenue-to-Cost Ratios as determined in CNPI in its combined Cost Allocation Informational Filing, submitted with this Application and attached to the Application as Exhibit 10, Tab 1, Schedule 2, Appendix A.

Customer Class Revenue-to-Cost Ratios		
Determined by the Combined Cost Allocation Informational Filing RUN # 2		
Customer Class	**Revenue-to-Cost Ratio**	**Over/(Under) Contribution**
Residential	80.52%	($1,252,058)
General Service Less Than 50 kW	133.51%	$403,707
General Service 50 to 4,999 kW	154.8%	$1,208,691
Unmetered Scattered Load	57.76%	($23,402)
Sentinel Lighting	37.46%	($44,779)
Street Lighting	19.51%	($292,158)

In the Report of the Board, Application of Cost Allocation for Electricity Distributors, EB-2007-0667, November 28, 2007, the Board concluded that there were appropriate ranges of the Revenue-to-Cost Ratio applicable to each customer class. The Board also concluded in its report that an incremental approach is appropriate in light of the influencing factors identified in the report, and that a range approach is preferable to implementation of a specific Revenue-to-Cost Ratio.

The ranges established by the Board are summarized in the table below and were intended as minimum requirements.

Board Concluded Revenue-to-Cost Ratio Ranges	
Report of the Board, Application of Cost Allocation for Electricity Distributors, EB-2007-0667	
Customer Class	**Range**
Residential	85% to 115%
General Service Less Than 50 kW	80% to 120%
General Service 50 to 4,999 kW	80% to 180%
Unmetered Scattered Load	80% to 120%
Sentinel Lighting	70% to 120%
Street Lighting	70% to 120%

CNPI has used the Revenue-to-Cost Ratios determined by the Board as one of the guiding principles in its harmonized electricity distribution rate design, Exhibit 10. In its rate design, CNPI has strived, where applicable, to move each customer class to a proposed 2009

Revenue-to-Cost Ratio within the range set by the Board while not moving any customer class further from unity. CNPI – Fort Erie has refrained from achieving this goal where mitigation of total bill impact has been required.

A summary of Revenue-to-Cost Ratios achieved by CNPI in its proposed rate design is summarized in the table below.

Customer Class Revenue-to-Cost Ratios Determined by the Harmonized Rate Design		
Customer Class	**Revenue-to-Cost Ratio**	**Over/(Under) Contribution**
Residential	82.88%	($1,208,958)
General Service Less Than 50 kW	120.00%	$263,656
General Service 50 to 4,999 kW	152.66%	$1,335,466
Unmetered Scattered Load	44.69%	($26,930)
Sentinel Lighting	54.61%	($38,148)
Street Lighting	23.91%	($325,086)

CNPI has allowed the Revenue-to-Cost Ratio to remain outside of the Board's specified range in order to maintain the proposed customer class total bill impact to a maximum of 10% thereby avoiding rate impact mitigation.

These results are discussed more fully in Exhibit 10 Tab 1 Schedule 3, Rate Design.

Transformer Ownership Allowance

In the Report of the Board, Application of Cost Allocation for Electricity Distributors, EB-2007-0667, November 28, 2007, the Board identified the issue of transformer credits for customers that own their own transformers as a matter to be addressed through the review of the cost allocation informational filings. This matter is also an issue in the current proceeding, Rate Design for Recovery of Electricity Distribution Costs, EB-2007-0031. In light of these matters, CNPI – Fort Erie is proposing the continuation of the current Board approved rate of $0.60 for the allowance for customer owned transformers in this Application.

APPENDIX A

Cost Allocation Information Filing Model

Ontario Energy Board

2006 COST ALLOCATION INFORMATION FILING

Sheet I1 Utility Information Sheet

Name of LDC:	Canadian Niagara Power Inc - Fort Erie & EOP
License Number:	
EDR 2006 EB Number:	
Cost Allocation EB Number:	(drop-down menu)
Date of Submission:	Monday, July 14, 2008
Version:	1.2

Contact Information

Name:	Doug Bradbury
Title:	Director, Regulatory Affairs
Phone Number:	905-994-3634
E-Mail Address:	doug.bradbury@fortisontario.com

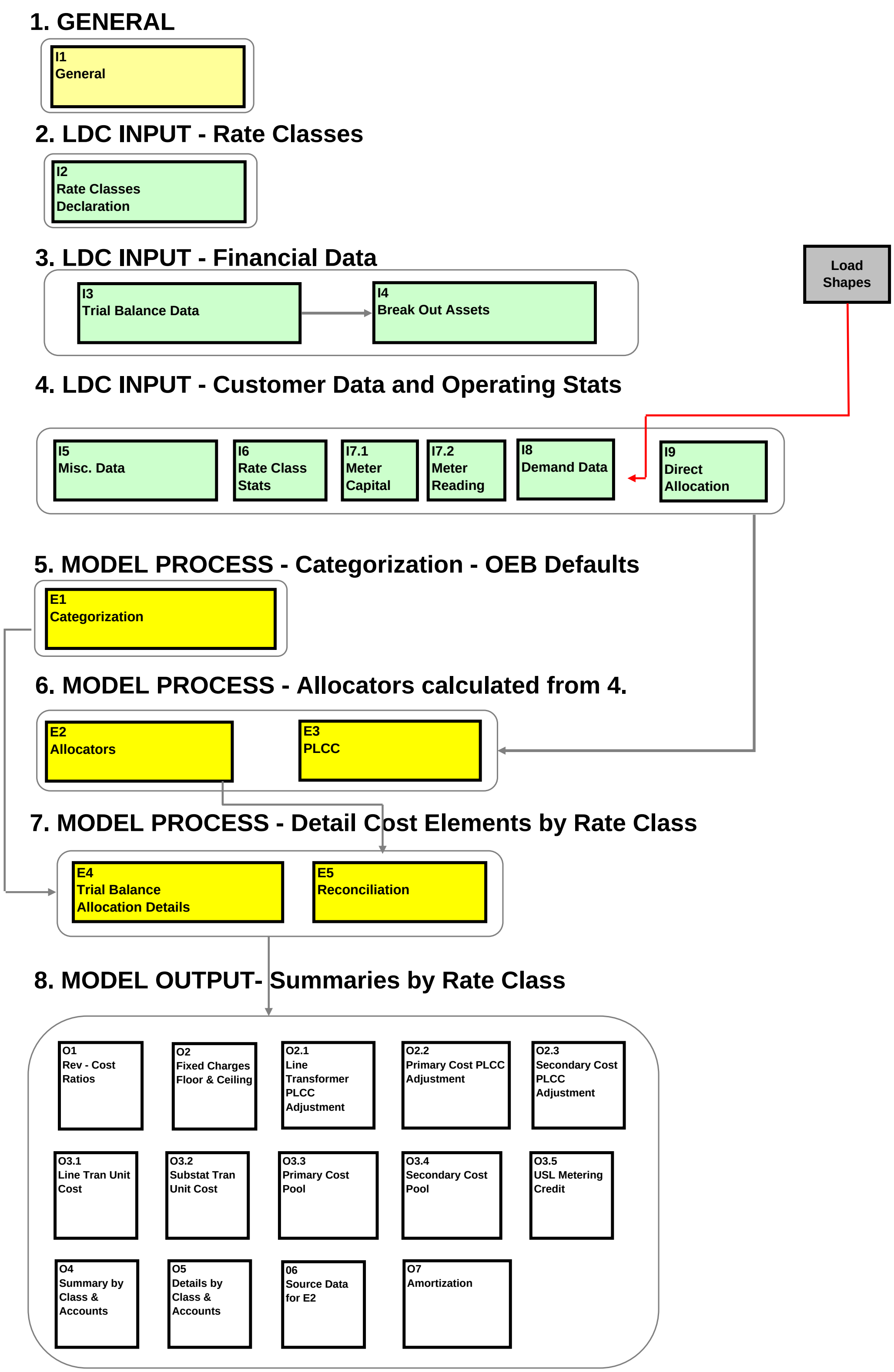
**Please Note: Colour Coding Legend **

Input Cells	
Output Cells	
Exhibition	
Brought Forward	Brought Forward
Calculation	Calculation
Default Numbers	
Diagnostic	

Brief Description of Each Worksheet's Function

INPUTS	I1	Intro	Brief explanation of what the pages do.
	I2	LDC data and Classes	Enter LDC specific information and number of classes etc
	I3	TB Data	Balance from approved 2006 EDR Trial Balance
	I4	BO ASSETS	Break out assets into detail functions - bulk deliver, primary and secondary
	I5	Misc Data	Input for miscellaneous data where necessary - TBD
	I6	Customer Data	Input customer related data for generating customer allocators
	I7.1	Meter Capital	Input meter related data for calculating capital costs weighing factors
	I7.2	Meter Reading	Input meter related data for calculating meter reading weighing factors
	I8	Demand Data	Input demand allocators using load data and making LDC specific adjustments
	I9	Direct Allocation	
OUTPUTS	O1	Revenue to cost	Output showing revenue to cost ratios, inter class subsidy etc.
	O2	Fixed Charge	Output showing the range for the Basic Customer charge - TBD
	O2.1	Line Transformer PLCC Adjustment	
	O2.2	Primary Cost PLCC Adjustment	
	O2.3	Secondary Cost PLCC Adjustment	
	O3.1	Line Tran Unit Cost	
	O3.2	Substat Tran Unit Cost	
	O3.3	Primary Cost Pool	
	O3.4	Secondary Cost Pool	
	O3.5	USL Metering Credit	
	O4	Summary by Class	Output showing summary of all allocation by class and by US of A
	O5	Detail by Class	Output showing details of individual allocation by class and by USofA
	O6	Source Data for E2	
	O7	Amortization	
EXHIBITS	E1	Categorization	Exhibit showing how costs are categorized
	E2	Allocation Factors	Exhibit summarizing all allocation factors created in I5 to I8 and present the findings in percentages
	E3	PLCC	Backup documentation for calculating Peak Load Carrying Capability.
	E4	Trial Balance Index	Exhibit showing 1. how accounts are grouped for reporting, how accounts are categorized and how accounts are allocated
	E5	Reconciliation	Exhibit showing reconciliation of accounts included and excluded from the allocation study to TB balance

I


1. GENERAL
I1
General
2. LDC INPUT - Rate Classes
I2
Rate Classes Declaration
3. LDC INPUT - Financial Data
I3
Trial Balance Data
I4
Break Out Assets
Load Shapes
4. LDC INPUT - Customer Data and Operating Stats
I5
Misc. Data
I6
Rate Class Stats
I7.1
Meter Capital
I7.2
Meter Reading
I8
Demand Data
I9
Direct Allocation
5. MODEL PROCESS - Categorization - OEB Defaults
E1
Categorization
6. MODEL PROCESS - Allocators calculated from 4.
E2
Allocators
E3
PLCC
7. MODEL PROCESS - Detail Cost Elements by Rate Class
E4
Trial Balance Allocation Details
E5
Reconciliation
8. MODEL OUTPUT- Summaries by Rate Class
O1
Rev - Cost Ratios
O2
Fixed Charges Floor & Ceiling
O2.1
Line Transformer PLCC Adjustment
O2.2
Primary Cost PLCC Adjustment
O2.3
Secondary Cost PLCC Adjustment
O3.1
Line Tran Unit Cost
O3.2
Substat Tran Unit Cost
O3.3
Primary Cost Pool
O3.4
Secondary Cost Pool
O3.5
USL Metering Credit
O4
Summary by Class & Accounts
O5
Details by Class & Accounts
06
Source Data for E2
O7
Amortization

2006 COST ALLOCATION INFORMATION FILING
Canadian Niagara Power Inc - Fort Erie & EOP

Monday, July 14, 2008
Sheet I2 Class Selection - Second Run

Instructions:
Step 1: Pleae input your existing classes
Step 2: If this is your first run, select "First Run" in the drop-down menu below
Step 3: After all classes have been entered, Click the "Update" button in row E41

Click for Drop-Down Menu → Second Run

If desired, provide a summary of this run (40 characters max.)

		Utility's Class Definition	Current
1	Residential		YES
2	GS <50		YES
3	GS>50-Regular		YES
4	GS> 50-TOU		NO
5	GS >50-Intermediate		NO
6	Large Use >5MW		NO
7	Street Light		YES
8	Sentinel		YES
9	Unmetered Scattered Load		YES
10	Embedded Distributor		NO
11	Back-up/Standby Power		NO
12	Rate Class 1		NO
13	Rate class 2		NO
14	Rate class 3		NO
15	Rate class 4		NO
16	Rate class 5		NO
17	Rate class 6		NO
18	Rate class 7		NO
19	Rate class 8		NO
20	Rate class 9		NO

Update

** **Space available for additional information about this run**

2006 COST ALLOCATION INFORMATION FILING

Canadian Niagara Power Inc - Fort Erie & EOP

Monday, July 14, 2008

Sheet I3 Trial Balance Data - Second Run

Instructions:

Step 1: Copy 2006 EDR Trial Balance values (Sheet 2-4, Column P17 to P446) to Column D21 of this worksheet. Use the Edit - *Paste Special - Values* function.

Step 2: Enter the amounts needed to be reclassified to column F.

Step 3: Enter Target Net Income from approved EDR (Sheet 4-1, cell F23)

Step 4: Enter PILs from approved EDR (Sheet 4-2, cell E15)

Step 5: Enter Interest from approved EDR (Sheet 4-1, cell F21)

Step 6: Enter specific service charges offset from approved EDR (Sheet 5-5, cell D19)

Step 7: Enter Transformation Ownership Allowance Credit from approved EDR (Sheet 6 3, cell R120)

Step 8: Enter Low Voltage Wheeling Adjustment Credit from approved EDR (Sheet ADJ 3, cell F46)

Step 9: Enter Revenue Requirement from approved EDR (Sheet 5-1, cell F22)

Step 10: Enter Total Rate Base from approved EDR (Sheet 3-1, cell F21)

Step 11: Enter Directly Allocated amounts into column G.

		From this Sheet	Differences?
Approved Target Net Income ($)	$1,522,192		
Approved PILs ($)	$166,398		
Approved Interest ($)	$1,199,487		
Approved Specific Service Charges ($)	$442,265		
Approved Transformer Ownership Allowance ($)	$153,529		
Approved Low Voltage Wheeling Adjustment ($)	$107,348		
Approved Revenue Requirement ($)	$10,282,492		
Revenue Requirement to be Used in this model ($)	$10,328,673	**$10,328,673**	**Rev Req Matches**
Approved Rate Base ($)	$33,826,488		
Rate Base to be Used in this model ($)	$33,833,415	**$33,833,415**	**Rate Base Matches**

Uniform System of Accounts - Detail Accounts

USoA Account #	Accounts		Financial Statement (EDR Sheet 2.4, Column P)	Model Adjustments	Reclassify accounts	Direct Allocation	Reclassified Balance	
1005	Cash		$0.00		$0.00	$0.00	$0	Unclassified Asset
1010	Cash Advances and Working Funds		$0.00		$0.00	$0.00	$0	Unclassified Asset
1020	Interest Special Deposits		$0.00		$0.00	$0.00	$0	Unclassified Asset
1030	Dividend Special Deposits		$0.00		$0.00	$0.00	$0	Unclassified Asset
1040	Other Special Deposits		$0.00		$0.00	$0.00	$0	Unclassified Asset
1060	Term Deposits		$0.00		$0.00	$0.00	$0	Unclassified Asset
1070	Current Investments		$0.00		$0.00	$0.00	$0	Unclassified Asset
1100	Customer Accounts Receivable		$0.00		$0.00	$0.00	$0	Unclassified Asset
1102	Accounts Receivable - Services		$0.00		$0.00	$0.00	$0	Unclassified Asset
1104	Accounts Receivable - Recoverable Work		$0.00		$0.00	$0.00	$0	Unclassified Asset
1105	Accounts Receivable - Merchandise, Jobbing, etc.		$0.00		$0.00	$0.00	$0	Unclassified Asset
1110	Other Accounts Receivable		$0.00		$0.00	$0.00	$0	Unclassified Asset
1120	Accrued Utility Revenues		$0.00		$0.00	$0.00	$0	Unclassified Asset
1130	Accumulated Provision for Uncollectible Accounts--Credit		$0.00		$0.00	$0.00	$0	Unclassified Asset
1140	Interest and Dividends Receivable		$0.00		$0.00	$0.00	$0	Unclassified Asset
1150	Rents Receivable		$0.00		$0.00	$0.00	$0	Unclassified Asset
1170	Notes Receivable		$0.00		$0.00	$0.00	$0	Unclassified Asset
1180	Prepayments		$0.00		$0.00	$0.00	$0	Unclassified Asset
1190	Miscellaneous Current and Accrued Assets		$0.00		$0.00	$0.00	$0	Unclassified Asset
1200	Accounts Receivable from Associated Companies		$0.00		$0.00	$0.00	$0	Unclassified Asset
1210	Notes Receivable from Associated Companies		$0.00		$0.00	$0.00	$0	Unclassified Asset
1305	Fuel Stock		$0.00		$0.00	$0.00	$0	Unclassified Asset
1330	Plant Materials and Operating Supplies		$0.00		$0.00	$0.00	$0	Unclassified Asset
1340	Merchandise		$0.00		$0.00	$0.00	$0	Unclassified Asset
1350	Other Materials and Supplies		$0.00		$0.00	$0.00	$0	Unclassified Asset
1405	Long Term Investments in Non-Associated Companies		$0.00		$0.00	$0.00	$0	Unclassified Asset
1408	Long Term Receivable - Street Lighting Transfer		$0.00		$0.00	$0.00	$0	Unclassified Asset
1410	Other Special or Collateral Funds		$0.00		$0.00	$0.00	$0	Unclassified Asset
1415	Sinking Funds		$0.00		$0.00	$0.00	$0	Unclassified Asset
1425	Unamortized Debt Expense		$0.00		$0.00	$0.00	$0	Unclassified Asset
1445	Unamortized Discount on Long-Term Debt--Debit		$0.00		$0.00	$0.00	$0	Unclassified Asset
1455	Unamortized Deferred Foreign Currency Translation Gains and Losses		$0.00		$0.00	$0.00	$0	Unclassified Asset
1460	Other Non-Current Assets		$0.00		$0.00	$0.00	$0	Unclassified Asset
1465	O.M.E.R.S. Past Service Costs		$0.00		$0.00	$0.00	$0	Unclassified Asset
1470	Past Service Costs - Employee Future Benefits		$0.00		$0.00	$0.00	$0	Unclassified Asset
1475	Past Service Costs - Other Pension Plans		$0.00		$0.00	$0.00	$0	Unclassified Asset
1480	Portfolio Investments - Associated Companies		$0.00		$0.00	$0.00	$0	Unclassified Asset
1485	Investment in Associated Companies - Significant Influence		$0.00		$0.00	$0.00	$0	Unclassified Asset
1490	Investment in Subsidiary Companies		$0.00		$0.00	$0.00	$0	Unclassified Asset
1505	Unrecovered Plant and Regulatory Study Costs		$0.00		$0.00	$0.00	$0	Unclassified Asset
1508	Other Regulatory Assets		$0.00		$0.00	$0.00	$0	Unclassified Asset
1510	Preliminary Survey and Investigation Charges		$0.00		$0.00	$0.00	$0	Unclassified Asset
1515	Emission Allowance Inventory		$0.00		$0.00	$0.00	$0	Unclassified Asset
1516	Emission Allowances Withheld		$0.00		$0.00	$0.00	$0	Unclassified Asset
1518	RCVARetail		$0.00		$0.00	$0.00	$0	Unclassified Asset
1520	Power Purchase Variance Account		$0.00		$0.00	$0.00	$0	Unclassified Asset
1525	Miscellaneous Deferred Debits		$0.00		$0.00	$0.00	$0	Unclassified Asset
1530	Deferred Losses from Disposition of Utility Plant		$0.00		$0.00	$0.00	$0	Unclassified Asset
1540	Unamortized Loss on Reacquired Debt		$0.00		$0.00	$0.00	$0	Unclassified Asset
1545	Development Charge Deposits/ Receivables		$0.00		$0.00	$0.00	$0	Unclassified Asset
1548	RCVASTR		$0.00		$0.00	$0.00	$0	Unclassified Asset
1560	Deferred Development Costs		$0.00		$0.00	$0.00	$0	Unclassified Asset
1562	Deferred Payments in Lieu of Taxes		$0.00		$0.00	$0.00	$0	Unclassified Asset
1563	Account 1563 - Deferred PILs Contra Account		$0.00		$0.00	$0.00	$0	Unclassified Asset
1565	Conservation and Demand Management Expenditures and Recoveries		$0.00		$0.00	$0.00	$0	CDM Expenditures and Recoveries
1570	Qualifying Transition Costs		$0.00		$0.00	$0.00	$0	Unclassified Asset
1571	Pre-market Opening Energy Variance		$0.00		$0.00	$0.00	$0	Unclassified Asset
1572	Extraordinary Event Costs		$0.00		$0.00	$0.00	$0	Unclassified Asset
1574	Deferred Rate Impact Amounts		$0.00		$0.00	$0.00	$0	Unclassified Asset
1580	RSVAWMS		$0.00		$0.00	$0.00	$0	Unclassified Asset

1582	RSVAONE-TIME	$0.00	$0.00	$0.00	$0	Unclassified Asset
1584	RSVANW	$0.00	$0.00	$0.00	$0	Unclassified Asset
1586	RSVACN	$0.00	$0.00	$0.00	$0	Unclassified Asset
1588	RSVAPOWER	$0.00	$0.00	$0.00	$0	Unclassified Asset
1590	Recovery of Regulatory Asset Balances	$0.00	$0.00	$0.00	$0	Unclassified Asset
1605	Electric Plant in Service - Control Account	$0.00	$0.00	$0.00	$0	Unclassified Asset
1606	Organization	$0.00	$0.00	$0.00	$0	Non-Distribution Asset
1608	Franchises and Consents	$0.00	$0.00	$0.00	$0	Other Distribution Assets
1610	Miscellaneous Intangible Plant	$0.00	$0.00	$0.00	$0	Non-Distribution Asset
1615	Land	$0.00	$0.00	$0.00	$0	Non-Distribution Asset
1616	Land Rights	$0.00	$0.00	$0.00	$0	Non-Distribution Asset
1620	Buildings and Fixtures	$0.00	$0.00	$0.00	$0	Non-Distribution Asset
1630	Leasehold Improvements	$0.00	$0.00	$0.00	$0	Non-Distribution Asset
1635	Boiler Plant Equipment	$0.00	$0.00	$0.00	$0	Non-Distribution Asset
1640	Engines and Engine-Driven Generators	$0.00	$0.00	$0.00	$0	Non-Distribution Asset
1645	Turbogenerator Units	$0.00	$0.00	$0.00	$0	Non-Distribution Asset
1650	Reservoirs, Dams and Waterways	$0.00	$0.00	$0.00	$0	Non-Distribution Asset
1655	Water Wheels, Turbines and Generators	$0.00	$0.00	$0.00	$0	Non-Distribution Asset
1660	Roads, Railroads and Bridges	$0.00	$0.00	$0.00	$0	Non-Distribution Asset
1665	Fuel Holders, Producers and Accessories	$0.00	$0.00	$0.00	$0	Non-Distribution Asset
1670	Prime Movers	$0.00	$0.00	$0.00	$0	Non-Distribution Asset
1675	Generators	$0.00	$0.00	$0.00	$0	Non-Distribution Asset
1680	Accessory Electric Equipment	$0.00	$0.00	$0.00	$0	Non-Distribution Asset
1685	Miscellaneous Power Plant Equipment	$0.00	$0.00	$0.00	$0	Non-Distribution Asset
1705	Land	$0.00	$0.00	$0.00	$0	Non-Distribution Asset
1706	Land Rights	$0.00	$0.00	$0.00	$0	Non-Distribution Asset
1708	Buildings and Fixtures	$0.00	$0.00	$0.00	$0	Non-Distribution Asset
1710	Leasehold Improvements	$0.00	$0.00	$0.00	$0	Non-Distribution Asset
1715	Station Equipment	$0.00	$0.00	$0.00	$0	Non-Distribution Asset
1720	Towers and Fixtures	$0.00	$0.00	$0.00	$0	Non-Distribution Asset
1725	Poles and Fixtures	$0.00	$0.00	$0.00	$0	Non-Distribution Asset
1730	Overhead Conductors and Devices	$0.00	$0.00	$0.00	$0	Non-Distribution Asset
1735	Underground Conduit	$0.00	$0.00	$0.00	$0	Non-Distribution Asset
1740	Underground Conductors and Devices	$0.00	$0.00	$0.00	$0	Non-Distribution Asset
1745	Roads and Trails	$0.00	$0.00	$0.00	$0	Non-Distribution Asset
1805	Land	$0.00	$0.00	$0.00	$0	Land and Buildings
1806	Land Rights	$104,138.31	$0.00	$0.00	$104,138	Land and Buildings
1808	Buildings and Fixtures	$2,845,621.28	$0.00	$0.00	$2,845,621	Land and Buildings
1810	Leasehold Improvements	$0.00	$0.00	$0.00	$0	Land and Buildings
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0.00	$0.00	$0.00	$0	TS Primary Above 50
1820	Distribution Station Equipment - Normally Primary below 50 kV	$2,942,645.32	$0.00	$0.00	$2,942,645	DS
1825	Storage Battery Equipment	$0.00	$0.00	$0.00	$0	Other Distribution Assets
1830	Poles, Towers and Fixtures	$9,701,516.37	$0.00	$0.00	$9,701,516	Poles, Wires
1835	Overhead Conductors and Devices	$11,036,201.87	-$2,933,114.96	$0.00	$8,103,087	Poles, Wires
1840	Underground Conduit	$486,355.36	$0.00	$0.00	$486,355	Poles, Wires
1845	Underground Conductors and Devices	$5,126,355.40	-$1,360,206.53	$0.00	$3,766,149	Poles, Wires
1850	Line Transformers	$7,102,674.33	$0.00	$0.00	$7,102,674	Line Transformers
1855	Services	$0.00	$4,293,321.49	$0.00	$4,293,321	Services and Meters
1860	Meters	$2,402,777.93	$0.00	$0.00	$2,402,778	Services and Meters
1865	Other Installations on Customer's Premises	$0.00	$0.00	$0.00	$0	Non-Distribution Asset
1870	Leased Property on Customer Premises	$0.00	$0.00	$0.00	$0	Non-Distribution Asset
1875	Street Lighting and Signal Systems	$0.00	$0.00	$0.00	$0	Non-Distribution Asset
1905	Land	$0.00	$0.00	$0.00	$0	Land and Buildings
1906	Land Rights	$0.00	$0.00	$0.00	$0	Land and Buildings
1908	Buildings and Fixtures	$386,539.24	$0.00	$0.00	$386,539	General Plant
1910	Leasehold Improvements	$0.00	$0.00	$0.00	$0	General Plant
1915	Office Furniture and Equipment	$1,150,789.63	$0.00	$0.00	$1,150,790	Equipment
1920	Computer Equipment - Hardware	$779,109.78	$0.00	$149,582.00	$629,528	IT Assets
1925	Computer Software	$1,950,241.57	$0.00	$599,140.00	$1,351,102	IT Assets
1930	Transportation Equipment	$413,246.94	$0.00	$0.00	$413,247	Equipment
1935	Stores Equipment	$96,772.03	$0.00	$0.00	$96,772	Equipment
1940	Tools, Shop and Garage Equipment	$623,491.15	$0.00	$0.00	$623,491	Equipment
1945	Measurement and Testing Equipment	$296,484.93	$0.00	$0.00	$296,485	Equipment
1950	Power Operated Equipment	$66,375.22	$0.00	$0.00	$66,375	Equipment
1955	Communication Equipment	$314,169.47	$0.00	$0.00	$314,169	Equipment
1960	Miscellaneous Equipment	$86,997.74	$0.00	$0.00	$86,998	Equipment
1965	Water Heater Rental Units	$0.00	$0.00	$0.00	$0	Non-Distribution Asset
1970	Load Management Controls - Customer Premises	$0.00	$0.00	$0.00	$0	Other Distribution Assets
1975	Load Management Controls - Utility Premises	$0.00	$0.00	$0.00	$0	Other Distribution Assets
1980	System Supervisory Equipment	$0.00	$0.00	$0.00	$0	Other Distribution Assets
1985	Sentinel Lighting Rental Units	$0.00	$0.00	$0.00	$0	Non-Distribution Asset
1990	Other Tangible Property	$0.00	$0.00	$0.00	$0	Other Distribution Assets
1995	Contributions and Grants - Credit	-$2,197,180.03	$0.00	$0.00	($2,197,180)	Contributions and Grants
2005	Property Under Capital Leases	$0.00	$0.00	$0.00	$0	Other Distribution Assets
2010	Electric Plant Purchased or Sold	$0.00	$0.00	$0.00	$0	Other Distribution Assets
2020	Experimental Electric Plant Unclassified	$0.00	$0.00	$0.00	$0	Non-Distribution Asset
2030	Electric Plant and Equipment Leased to Others	$0.00	$0.00	$0.00	$0	Non-Distribution Asset
2040	Electric Plant Held for Future Use	$0.00	$0.00	$0.00	$0	Non-Distribution Asset
2050	Completed Construction Not Classified--Electric	$0.00	$0.00	$0.00	$0	Other Distribution Assets
2055	Construction Work in Progress--Electric	$0.00	$0.00	$0.00	$0	Non-Distribution Asset
2060	Electric Plant Acquisition Adjustment	$0.00	$0.00	$0.00	$0	Unclassified Asset
2065	Other Electric Plant Adjustment	$0.00	$0.00	$0.00	$0	Non-Distribution Asset
2070	Other Utility Plant	$0.00	$0.00	$0.00	$0	Non-Distribution Asset
2075	Non-Utility Property Owned or Under Capital Leases	$0.00	$0.00	$0.00	$0	Non-Distribution Asset
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	-$16,708,331.50	$0.00	$0.00	($16,708,331)	Accumulated Amortization
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	-$11,941.30	$0.00	$0.00	($11,941)	Accumulated Amortization
2140	Accumulated Amortization of Electric Plant Acquisition Adjustment	$0.00	$0.00	$0.00	$0	Unclassified Asset
2160	Accumulated Amortization of Other Utility Plant	$0.00	$0.00	$0.00	$0	Non-Distribution Asset
2180	Accumulated Amortization of Non-Utility Property	$0.00	$0.00	$0.00	$0	Non-Distribution Asset
2205	Accounts Payable	$0.00	$0.00	$0.00	$0	Liability
2208	Customer Credit Balances	$0.00	$0.00	$0.00	$0	Liability
2210	Current Portion of Customer Deposits	$0.00	$0.00	$0.00	$0	Liability
2215	Dividends Declared	$0.00	$0.00	$0.00	$0	Liability
2220	Miscellaneous Current and Accrued Liabilities	$0.00	$0.00	$0.00	$0	Liability
2225	Notes and Loans Payable	$0.00	$0.00	$0.00	$0	Liability
2240	Accounts Payable to Associated Companies	$0.00	$0.00	$0.00	$0	Liability
2242	Notes Payable to Associated Companies	$0.00	$0.00	$0.00	$0	Liability
2250	Debt Retirement Charges(DRC) Payable	$0.00	$0.00	$0.00	$0	Liability
2252	Transmission Charges Payable	$0.00	$0.00	$0.00	$0	Liability
2254	Electrical Safety Authority Fees Payable	$0.00	$0.00	$0.00	$0	Liability
2256	Independent Market Operator Fees and Penalties Payable	$0.00	$0.00	$0.00	$0	Liability
2260	Current Portion of Long Term Debt	$0.00	$0.00	$0.00	$0	Liability
2262	Ontario Hydro Debt - Current Portion	$0.00	$0.00	$0.00	$0	Liability
2264	Pensions and Employee Benefits - Current Portion	$0.00	$0.00	$0.00	$0	Liability
2268	Accrued Interest on Long Term Debt	$0.00	$0.00	$0.00	$0	Liability
2270	Matured Long Term Debt	$0.00	$0.00	$0.00	$0	Liability
2272	Matured Interest on Long Term Debt	$0.00	$0.00	$0.00	$0	Liability
2285	Obligations Under Capital Leases--Current	$0.00	$0.00	$0.00	$0	Liability
2290	Commodity Taxes	$0.00	$0.00	$0.00	$0	Liability
2292	Payroll Deductions / Expenses Payable	$0.00	$0.00	$0.00	$0	Liability
2294	Accrual for Taxes, Payments in Lieu of Taxes, Etc.	$0.00	$0.00	$0.00	$0	Liability
2296	Future Income Taxes - Current	$0.00	$0.00	$0.00	$0	Liability
2305	Accumulated Provision for Injuries and Damages	$0.00	$0.00	$0.00	$0	Liability
2306	Employee Future Benefits	$0.00	$0.00	$0.00	$0	Liability
2308	Other Pensions - Past Service Liability	$0.00	$0.00	$0.00	$0	Liability
2310	Vested Sick Leave Liability	$0.00	$0.00	$0.00	$0	Liability
2315	Accumulated Provision for Rate Refunds	$0.00	$0.00	$0.00	$0	Liability
2320	Other Miscellaneous Non-Current Liabilities	$0.00	$0.00	$0.00	$0	Liability
2325	Obligations Under Capital Lease--Non-Current	$0.00	$0.00	$0.00	$0	Liability
2330	Development Charge Fund	$0.00	$0.00	$0.00	$0	Liability
2335	Long Term Customer Deposits	$0.00	$0.00	$0.00	$0	Liability
2340	Collateral Funds Liability	$0.00	$0.00	$0.00	$0	Liability

2345	Unamortized Premium on Long Term Debt		$0.00		$0.00	$0.00	$0	Liability
2348	O.M.E.R.S. - Past Service Liability - Long Term Portion		$0.00		$0.00	$0.00	$0	Liability
2350	Future Income Tax - Non-Current		$0.00		$0.00	$0.00	$0	Liability
2405	Other Regulatory Liabilities		$0.00		$0.00	$0.00	$0	Liability
2410	Deferred Gains from Disposition of Utility Plant		$0.00		$0.00	$0.00	$0	Liability
2415	Unamortized Gain on Reacquired Debt		$0.00		$0.00	$0.00	$0	Liability
2425	Other Deferred Credits		$0.00		$0.00	$0.00	$0	Liability
2435	Accrued Rate-Payer Benefit		$0.00		$0.00	$0.00	$0	Liability
2505	Debentures Outstanding - Long Term Portion		$0.00		$0.00	$0.00	$0	Liability
2510	Debenture Advances		$0.00		$0.00	$0.00	$0	Liability
2515	Reacquired Bonds		$0.00		$0.00	$0.00	$0	Liability
2520	Other Long Term Debt		$0.00		$0.00	$0.00	$0	Liability
2525	Term Bank Loans - Long Term Portion		$0.00		$0.00	$0.00	$0	Liability
2530	Ontario Hydro Debt Outstanding - Long Term Portion		$0.00		$0.00	$0.00	$0	Liability
2550	Advances from Associated Companies		$0.00		$0.00	$0.00	$0	Liability
3005	Common Shares Issued		$0.00		$0.00	$0.00	$0	Equity
3008	Preference Shares Issued		$0.00		$0.00	$0.00	$0	Equity
3010	Contributed Surplus		$0.00		$0.00	$0.00	$0	Equity
3020	Donations Received		$0.00		$0.00	$0.00	$0	Equity
3022	Development Charges Transferred to Equity		$0.00		$0.00	$0.00	$0	Equity
3026	Capital Stock Held in Treasury		$0.00		$0.00	$0.00	$0	Equity
3030	Miscellaneous Paid-In Capital		$0.00		$0.00	$0.00	$0	Equity
3035	Installments Received on Capital Stock		$0.00		$0.00	$0.00	$0	Equity
3040	Appropriated Retained Earnings		$0.00		$0.00	$0.00	$0	Equity
3045	Unappropriated Retained Earnings		$0.00		$0.00	$0.00	$0	Equity
3046	Balance Transferred From Income		$0.00	$0	$0.00	$27,299.29	($1,494,893)	Equity
3047	Appropriations of Retained Earnings - Current Period		$0.00		$0.00	$0.00	$0	Equity
3048	Dividends Payable-Preference Shares		$0.00		$0.00	$0.00	$0	Equity
3049	Dividends Payable-Common Shares		$0.00		$0.00	$0.00	$0	Equity
3055	Adjustment to Retained Earnings		$0.00		$0.00	$0.00	$0	Equity
3065	Unappropriated Undistributed Subsidiary Earnings		$0.00		$0.00	$0.00	$0	Equity
4006	Residential Energy Sales		-$6,229,086.84		$0.00	$0.00	($6,229,087)	Sales of Electricity
4010	Commercial Energy Sales		-$2,283,044.81		$0.00	$0.00	($2,283,045)	Sales of Electricity
4015	Industrial Energy Sales		-$8,210,143.99		$0.00	$0.00	($8,210,144)	Sales of Electricity
4020	Energy Sales to Large Users		$0.00		$0.00	$0.00	$0	Sales of Electricity
4025	Street Lighting Energy Sales		-$238,371.83		$0.00	$0.00	($238,372)	Sales of Electricity
4030	Sentinel Lighting Energy Sales		-$102,818.12		$0.00	$0.00	($102,818)	Sales of Electricity
4035	General Energy Sales		-$352.43		$0.00	$0.00	($352)	Sales of Electricity
4040	Other Energy Sales to Public Authorities		$0.00		$0.00	$0.00	$0	Sales of Electricity
4045	Energy Sales to Railroads and Railways		$0.00		$0.00	$0.00	$0	Sales of Electricity
4050	Revenue Adjustment		$0.00		$0.00	$0.00	$0	Sales of Electricity
4055	Energy Sales for Resale		-$1,556,194.22		$0.00	$0.00	($1,556,194)	Sales of Electricity
4060	Interdepartmental Energy Sales		-$89,120.33		$0.00	$0.00	($89,120)	Sales of Electricity
4062	Billed WMS		-$2,242,394.68		$0.00	$0.00	($2,242,395)	Sales of Electricity
4064	Billed-One-Time		-$2,481,439.78		$0.00	$0.00	($2,481,440)	Sales of Electricity
4066	Billed NW		-$2,228,634.45		$0.00	$0.00	($2,228,634)	Sales of Electricity
4068	Billed CN		$0.00		$0.00	$0.00	$0	Sales of Electricity
4080	Distribution Services Revenue		-$9,158,703.54	$652,066	$0.00	$0.00	($9,810,770)	Distribution Services Revenue
4082	Retail Services Revenues		-$6,455.14		$0.00	$0.00	($6,455)	Other Distribution Revenue
4084	Service Transaction Requests (STR) Revenues		-$80.25		$0.00	$0.00	($80)	Other Distribution Revenue
4090	Electric Services Incidental to Energy Sales		$0.00		$0.00	$0.00	$0	Other Distribution Revenue
4105	Transmission Charges Revenue		$0.00		$0.00	$0.00	$0	Other Revenue - Unclassified
4110	Transmission Services Revenue		$0.00		$0.00	$0.00	$0	Other Revenue - Unclassified
4205	Interdepartmental Rents		$0.00		$0.00	$0.00	$0	Other Distribution Revenue
4210	Rent from Electric Property		$99,716.08		$0.00	$0.00	$99,716	Other Distribution Revenue
4215	Other Utility Operating Income		$0.00		$0.00	$0.00	$0	Other Distribution Revenue
4220	Other Electric Revenues		-$133,180.75		$0.00	$0.00	($133,181)	Other Distribution Revenue
4225	Late Payment Charges		-$71,821.30		$0.00	$0.00	($71,821)	Late Payment Charges
4230	Sales of Water and Water Power		$0.00		$0.00	$0.00	$0	Other Revenue - Unclassified
4235	Miscellaneous Service Revenues		-$80,153.27	$80,153	$0.00	$0.00	($442,265)	Specific Service Charges
4240	Provision for Rate Refunds		$0.00		$0.00	$0.00	$0	Other Distribution Revenue
4245	Government Assistance Directly Credited to Income		$0.00		$0.00	$0.00	$0	Other Distribution Revenue
4305	Regulatory Debits		$0.00		$0.00	$0.00	$0	Other Income & Deductions
4310	Regulatory Credits		$0.00		$0.00	$0.00	$0	Other Income & Deductions
4315	Revenues from Electric Plant Leased to Others		$0.00		$0.00	$0.00	$0	Other Income & Deductions
4320	Expenses of Electric Plant Leased to Others		$0.00		$0.00	$0.00	$0	Other Income & Deductions
4325	Revenues from Merchandise, Jobbing, Etc.		-$1,695.28		$0.00	$0.00	($1,695)	Other Income & Deductions
4330	Costs and Expenses of Merchandising, Jobbing, Etc.		-$28,338.39		$0.00	$0.00	($28,338)	Other Income & Deductions
4335	Profits and Losses from Financial Instrument Hedges		$0.00		$0.00	$0.00	$0	Other Income & Deductions
4340	Profits and Losses from Financial Instrument Investments		$0.00		$0.00	$0.00	$0	Other Income & Deductions
4345	Gains from Disposition of Future Use Utility Plant		$0.00		$0.00	$0.00	$0	Other Income & Deductions
4350	Losses from Disposition of Future Use Utility Plant		$0.00		$0.00	$0.00	$0	Other Income & Deductions
4355	Gain on Disposition of Utility and Other Property		$0.00		$0.00	$0.00	$0	Other Income & Deductions
4360	Loss on Disposition of Utility and Other Property		$11,503.01		$0.00	$0.00	$11,503	Other Income & Deductions
4365	Gains from Disposition of Allowances for Emission		$0.00		$0.00	$0.00	$0	Other Income & Deductions
4370	Losses from Disposition of Allowances for Emission		$0.00		$0.00	$0.00	$0	Other Income & Deductions
4375	Revenues from Non-Utility Operations		$0.00		$0.00	$0.00	$0	Other Revenue - Unclassified
4380	Expenses of Non-Utility Operations		$0.00		$0.00	$0.00	$0	Other Revenue - Unclassified
4385	Non-Utility Rental Income		$0.00		$0.00	$0.00	$0	Other Revenue - Unclassified
4390	Miscellaneous Non-Operating Income		$0.00		$0.00	$0.00	$0	Other Income & Deductions
4395	Rate-Payer Benefit Including Interest		$0.00		$0.00	$0.00	$0	Other Income & Deductions
4398	Foreign Exchange Gains and Losses, Including Amortization		-$22,681.85		$0.00	$0.00	($22,682)	Other Income & Deductions
4405	Interest and Dividend Income		$77,395.00		$0.00	$0.00	$77,395	Other Income & Deductions
4415	Equity in Earnings of Subsidiary Companies		$0.00		$0.00	$0.00	$0	Other Income & Deductions
4505	Operation Supervision and Engineering		$0.00		$0.00	$0.00	$0	Non-Distribution Expenses
4510	Fuel		$0.00		$0.00	$0.00	$0	Non-Distribution Expenses
4515	Steam Expense		$0.00		$0.00	$0.00	$0	Non-Distribution Expenses
4520	Steam From Other Sources		$0.00		$0.00	$0.00	$0	Non-Distribution Expenses
4525	Steam Transferred--Credit		$0.00		$0.00	$0.00	$0	Non-Distribution Expenses
4530	Electric Expense		$0.00		$0.00	$0.00	$0	Non-Distribution Expenses
4535	Water For Power		$0.00		$0.00	$0.00	$0	Non-Distribution Expenses
4540	Water Power Taxes		$0.00		$0.00	$0.00	$0	Non-Distribution Expenses
4545	Hydraulic Expenses		$0.00		$0.00	$0.00	$0	Non-Distribution Expenses
4550	Generation Expense		$0.00		$0.00	$0.00	$0	Non-Distribution Expenses
4555	Miscellaneous Power Generation Expenses		$0.00		$0.00	$0.00	$0	Non-Distribution Expenses
4560	Rents		$0.00		$0.00	$0.00	$0	Non-Distribution Expenses
4565	Allowances for Emissions		$0.00		$0.00	$0.00	$0	Non-Distribution Expenses
4605	Maintenance Supervision and Engineering		$0.00		$0.00	$0.00	$0	Non-Distribution Expenses
4610	Maintenance of Structures		$0.00		$0.00	$0.00	$0	Non-Distribution Expenses
4615	Maintenance of Boiler Plant		$0.00		$0.00	$0.00	$0	Non-Distribution Expenses
4620	Maintenance of Electric Plant		$0.00		$0.00	$0.00	$0	Non-Distribution Expenses
4625	Maintenance of Reservoirs, Dams and Waterways		$0.00		$0.00	$0.00	$0	Non-Distribution Expenses
4630	Maintenance of Water Wheels, Turbines and Generators		$0.00		$0.00	$0.00	$0	Non-Distribution Expenses
4635	Maintenance of Generating and Electric Plant		$0.00		$0.00	$0.00	$0	Non-Distribution Expenses
4640	Maintenance of Miscellaneous Power Generation Plant		$0.00		$0.00	$0.00	$0	Non-Distribution Expenses
4705	Power Purchased		$18,583,494.51		$0.00	$0.00	$18,583,495	Power Supply Expenses (Working Capital)
4708	Charges-WMS		$2,242,394.68		$0.00	$0.00	$2,242,395	Power Supply Expenses (Working Capital)
4710	Cost of Power Adjustments		$963,849.00		$0.00	$0.00	$963,849	Power Supply Expenses (Working Capital)
4712	Charges-One-Time		$0.00		$0.00	$0.00	$0	Power Supply Expenses (Working Capital)
4714	Charges-NW		$2,481,439.78		$0.00	$0.00	$2,481,440	Power Supply Expenses (Working Capital)
4715	System Control and Load Dispatching		$0.00		$0.00	$0.00	$0	Other Power Supply Expenses
4716	Charges-CN		$2,228,634.45		$0.00	$0.00	$2,228,634	Power Supply Expenses (Working Capital)
4720	Other Expenses		$0.00		$0.00	$0.00	$0	Other Power Supply Expenses
4725	Competition Transition Expense		$0.00		$0.00	$0.00	$0	Other Power Supply Expenses
4730	Rural Rate Assistance Expense		$0.00		$0.00	$0.00	$0	Power Supply Expenses (Working Capital)
4805	Operation Supervision and Engineering		$0.00		$0.00	$0.00	$0	Non-Distribution Expenses
4810	Load Dispatching		$0.00		$0.00	$0.00	$0	Non-Distribution Expenses
4815	Station Buildings and Fixtures Expenses		$0.00		$0.00	$0.00	$0	Non-Distribution Expenses
4820	Transformer Station Equipment - Operating Labour		$0.00		$0.00	$0.00	$0	Non-Distribution Expenses
4825	Transformer Station Equipment - Operating Supplies and Expense		$0.00		$0.00	$0.00	$0	Non-Distribution Expenses
4830	Overhead Line Expenses		$0.00		$0.00	$0.00	$0	Non-Distribution Expenses
4835	Underground Line Expenses		$0.00		$0.00	$0.00	$0	Non-Distribution Expenses

4840	Transmission of Electricity by Others	$0.00		$0.00	$0.00	$0	Non-Distribution Expenses
4845	Miscellaneous Transmission Expense	$0.00		$0.00	$0.00	$0	Non-Distribution Expenses
4850	Rents	$0.00		$0.00	$0.00	$0	Non-Distribution Expenses
4905	Maintenance Supervision and Engineering	$0.00		$0.00	$0.00	$0	Non-Distribution Expenses
4910	Maintenance of Transformer Station Buildings and Fixtures	$0.00		$0.00	$0.00	$0	Non-Distribution Expenses
4916	Maintenance of Transformer Station Equipment	$0.00		$0.00	$0.00	$0	Non-Distribution Expenses
4930	Maintenance of Towers, Poles and Fixtures	$0.00		$0.00	$0.00	$0	Non-Distribution Expenses
4935	Maintenance of Overhead Conductors and Devices	$0.00		$0.00	$0.00	$0	Non-Distribution Expenses
4940	Maintenance of Overhead Lines - Right of Way	$0.00		$0.00	$0.00	$0	Non-Distribution Expenses
4945	Maintenance of Overhead Lines - Roads and Trails Repairs	$0.00		$0.00	$0.00	$0	Non-Distribution Expenses
4950	Maintenance of Overhead Lines - Snow Removal from Roads and Trails	$0.00		$0.00	$0.00	$0	Non-Distribution Expenses
4960	Maintenance of Underground Lines	$0.00		$0.00	$0.00	$0	Non-Distribution Expenses
4965	Maintenance of Miscellaneous Transmission Plant	$0.00		$0.00	$0.00	$0	Non-Distribution Expenses
5005	Operation Supervision and Engineering	$14,047.50		$0.00	$0.00	$14,048	Operation (Working Capital)
5010	Load Dispatching	$145,095.00		$0.00	$0.00	$145,095	Operation (Working Capital)
5012	Station Buildings and Fixtures Expense	$94,037.54		$0.00	$0.00	$94,038	Operation (Working Capital)
5014	Transformer Station Equipment - Operation Labour	$0.00		$0.00	$0.00	$0	Operation (Working Capital)
5015	Transformer Station Equipment - Operation Supplies and Expenses	$0.00		$0.00	$0.00	$0	Operation (Working Capital)
5016	Distribution Station Equipment - Operation Labour	$51,573.29		$0.00	$0.00	$51,573	Operation (Working Capital)
5017	Distribution Station Equipment - Operation Supplies and Expenses	$3,978.43		$0.00	$0.00	$3,978	Operation (Working Capital)
5020	Overhead Distribution Lines and Feeders - Operation Labour	$48,025.30		$0.00	$0.00	$48,025	Operation (Working Capital)
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$22,234.91		$0.00	$0.00	$22,235	Operation (Working Capital)
5030	Overhead Subtransmission Feeders - Operation	$0.00		$0.00	$0.00	$0	Operation (Working Capital)
5035	Overhead Distribution Transformers- Operation	$22,180.79	$29,713	$0.00	$0.00	$51,894	Operation (Working Capital)
5040	Underground Distribution Lines and Feeders - Operation Labour	$85,572.44		$0.00	$0.00	$85,572	Operation (Working Capital)
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$951.99		$0.00	$0.00	$952	Operation (Working Capital)
5050	Underground Subtransmission Feeders - Operation	$0.00		$0.00	$0.00	$0	Operation (Working Capital)
5055	Underground Distribution Transformers - Operation	$6,487.50	$8,691	$0.00	$0.00	$15,178	Operation (Working Capital)
5060	Street Lighting and Signal System Expense	$0.00		$0.00	$0.00	$0	Non-Distribution Expenses
5065	Meter Expense	$154,933.04		$0.00	$0.00	$154,933	Operation (Working Capital)
5070	Customer Premises - Operation Labour	$1,955.00		$0.00	$0.00	$1,955	Operation (Working Capital)
5075	Customer Premises - Materials and Expenses	$9,406.30		$0.00	$0.00	$9,406	Operation (Working Capital)
5085	Miscellaneous Distribution Expense	$309,632.74		$0.00	$0.00	$309,633	Operation (Working Capital)
5090	Underground Distribution Lines and Feeders - Rental Paid	$0.00		$0.00	$0.00	$0	Operation (Working Capital)
5095	Overhead Distribution Lines and Feeders - Rental Paid	$0.00		$0.00	$0.00	$0	Operation (Working Capital)
5096	Other Rent	$2,135.00		$0.00	$0.00	$2,135	Operation (Working Capital)
5105	Maintenance Supervision and Engineering	$42,247.10		$0.00	$0.00	$42,247	Maintenance (Working Capital)
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$5,324.06		$0.00	$0.00	$5,324	Maintenance (Working Capital)
5112	Maintenance of Transformer Station Equipment	$0.00		$0.00	$0.00	$0	Maintenance (Working Capital)
5114	Maintenance of Distribution Station Equipment	$35,608.19		$0.00	$0.00	$35,608	Maintenance (Working Capital)
5120	Maintenance of Poles, Towers and Fixtures	$81,251.04		$0.00	$0.00	$81,251	Maintenance (Working Capital)
5125	Maintenance of Overhead Conductors and Devices	$280,899.01		$0.00	$0.00	$280,899	Maintenance (Working Capital)
5130	Maintenance of Overhead Services	$211,249.83		$0.00	$0.00	$211,250	Maintenance (Working Capital)
5135	Overhead Distribution Lines and Feeders - Right of Way	$176,548.98		$0.00	$0.00	$176,549	Maintenance (Working Capital)
5145	Maintenance of Underground Conduit	$11,050.24		$0.00	$0.00	$11,050	Maintenance (Working Capital)
5150	Maintenance of Underground Conductors and Devices	$43,843.69		$0.00	$0.00	$43,844	Maintenance (Working Capital)
5155	Maintenance of Underground Services	$33,616.57		$0.00	$0.00	$33,617	Maintenance (Working Capital)
5160	Maintenance of Line Transformers	$85,941.50	$115,126	$0.00	$0.00	$201,067	Maintenance (Working Capital)
5165	Maintenance of Street Lighting and Signal Systems	$20,748.84		$0.00	$0.00	$20,749	Non-Distribution Expenses
5170	Sentinel Lights - Labour	$0.00		$0.00	$0.00	$0	Non-Distribution Expenses
5172	Sentinel Lights - Materials and Expenses	$1,500.00		$0.00	$0.00	$1,500	Non-Distribution Expenses
5175	Maintenance of Meters	$72,985.81		$0.00	$0.00	$72,986	Maintenance (Working Capital)
5178	Customer Installations Expenses- Leased Property	$0.00		$0.00	$0.00	$0	Non-Distribution Expenses
5185	Water Heater Rentals - Labour	$0.00		$0.00	$0.00	$0	Non-Distribution Expenses
5186	Water Heater Rentals - Materials and Expenses	$0.00		$0.00	$0.00	$0	Non-Distribution Expenses
5190	Water Heater Controls - Labour	$0.00		$0.00	$0.00	$0	Non-Distribution Expenses
5192	Water Heater Controls - Materials and Expenses	$0.00		$0.00	$0.00	$0	Non-Distribution Expenses
5195	Maintenance of Other Installations on Customer Premises	$4,737.60		$0.00	$0.00	$4,738	Non-Distribution Expenses
5205	Purchase of Transmission and System Services	$0.00		$0.00	$0.00	$0	Other Power Supply Expenses
5210	Transmission Charges	$0.00		$0.00	$0.00	$0	Other Power Supply Expenses
5215	Transmission Charges Recovered	$0.00		$0.00	$0.00	$0	Other Power Supply Expenses
5305	Supervision	$0.00		$0.00	$0.00	$0	Billing and Collection (Working Capital)
5310	Meter Reading Expense	$244,533.07		$0.00	$0.00	$244,533	Billing and Collection (Working Capital)
5315	Customer Billing	$348,369.91		$0.00	$0.00	$348,370	Billing and Collection (Working Capital)
5320	Collecting	$114,921.40		$0.00	$0.00	$114,921	Billing and Collection (Working Capital)
5325	Collecting- Cash Over and Short	$625.85		$0.00	$0.00	$626	Billing and Collection (Working Capital)
5330	Collection Charges	$4,262.01		$0.00	$0.00	$4,262	Billing and Collection (Working Capital)
5335	Bad Debt Expense	$91,750.45		$0.00	$0.00	$91,750	Bad Debt Expense (Working Capital)
5340	Miscellaneous Customer Accounts Expenses	$302,965.05		$54,300.00	$0.00	$357,265	Billing and Collection (Working Capital)
5405	Supervision	$0.00		$0.00	$0.00	$0	Community Relations (Working Capital)
5410	Community Relations - Sundry	$0.00		$0.00	$0.00	$0	Community Relations (Working Capital)
5415	Energy Conservation	$0.00		$0.00	$0.00	$0	Community Relations - CDM (Working Capital)
5420	Community Safety Program	$0.00		$0.00	$0.00	$0	Community Relations (Working Capital)
5425	Miscellaneous Customer Service and Informational Expenses	$0.00		$0.00	$0.00	$0	Community Relations (Working Capital)
5505	Supervision	$0.00		$0.00	$0.00	$0	Other Distribution Expenses
5510	Demonstrating and Selling Expense	$0.00		$0.00	$0.00	$0	Other Distribution Expenses
5515	Advertising Expense	$0.00		$0.00	$0.00	$0	Advertising Expenses
5520	Miscellaneous Sales Expense	$0.00		$0.00	$0.00	$0	Other Distribution Expenses
5605	Executive Salaries and Expenses	$1,063,678.79		$0.00	$0.00	$1,063,679	Administrative and General Expenses (Working Capital)
5610	Management Salaries and Expenses	$0.00		$0.00	$0.00	$0	Administrative and General Expenses (Working Capital)
5615	General Administrative Salaries and Expenses	$1,994,625.16		$0.00	$0.00	$1,994,625	Administrative and General Expenses (Working Capital)
5620	Office Supplies and Expenses	$577,667.81		$0.00	$0.00	$577,668	Administrative and General Expenses (Working Capital)
5625	Administrative Expense Transferred Credit	-$3,125,909.50		$0.00	$0.00	($3,125,910)	Administrative and General Expenses (Working Capital)
5630	Outside Services Employed	$232,929.70		$0.00	$0.00	$232,930	Administrative and General Expenses (Working Capital)
5635	Property Insurance	$100,616.22		$0.00	$0.00	$100,616	Insurance Expense (Working Capital)
5640	Injuries and Damages	$125.00		$0.00	$0.00	$125	Administrative and General Expenses (Working Capital)
5645	Employee Pensions and Benefits	$404,529.08		$0.00	$0.00	$404,529	Administrative and General Expenses (Working Capital)
5650	Franchise Requirements	$0.00		$0.00	$0.00	$0	Administrative and General Expenses (Working Capital)
5655	Regulatory Expenses	$88,457.55		$0.00	$0.00	$88,458	Administrative and General Expenses (Working Capital)
5660	General Advertising Expenses	$6,401.99		$0.00	$0.00	$6,402	Advertising Expenses
5665	Miscellaneous General Expenses	$353,231.75	($107,348)	$0.00	$0.00	$245,884	Administrative and General Expenses (Working Capital)
5670	Rent	$350,518.55		$0.00	$0.00	$350,519	Administrative and General Expenses (Working Capital)
5675	Maintenance of General Plant	$431,247.13		-$54,300.00	$0.00	$376,947	Administrative and General Expenses (Working Capital)
5680	Electrical Safety Authority Fees	$0.00		$0.00	$0.00	$0	Administrative and General Expenses (Working Capital)
5685	Independent Market Operator Fees and Penalties	$0.00		$0.00	$0.00	$0	Power Supply Expenses (Working Capital)
5705	Amortization Expense - Property, Plant, and Equipment	$1,678,904.97		$0.00	$0.00	$1,678,905	Amortization of Assets
5710	Amortization of Limited Term Electric Plant	$0.00		$0.00	$0.00	$0	Amortization of Assets
5715	Amortization of Intangibles and Other Electric Plant	$5,745.79		$0.00	$0.00	$5,746	Amortization of Assets
5720	Amortization of Electric Plant Acquisition Adjustments	$0.00		$0.00	$0.00	$0	Other Amortization - Unclassified
5725	Miscellaneous Amortization	$0.00		$0.00	$0.00	$0	Other Amortization - Unclassified
5730	Amortization of Unrecovered Plant and Regulatory Study Costs	$0.00		$0.00	$0.00	$0	Amortization of Assets
5735	Amortization of Deferred Development Costs	$0.00		$0.00	$0.00	$0	Amortization of Assets
5740	Amortization of Deferred Charges	$0.00		$0.00	$0.00	$0	Amortization of Assets
6005	Interest on Long Term Debt	$0.00	$0	$0.00	$21,511.84	$1,177,975	Interest Expense - Unclassifed
6010	Amortization of Debt Discount and Expense	$0.00		$0.00	$0.00	$0	Interest Expense - Unclassifed
6015	Amortization of Premium on Debt Credit	$0.00		$0.00	$0.00	$0	Interest Expense - Unclassifed
6020	Amortization of Loss on Reacquired Debt	$0.00		$0.00	$0.00	$0	Interest Expense - Unclassifed
6025	Amortization of Gain on Reacquired Debt--Credit	$0.00		$0.00	$0.00	$0	Interest Expense - Unclassifed
6030	Interest on Debt to Associated Companies	$0.00		$0.00	$0.00	$0	Interest Expense - Unclassifed

6035	Other Interest Expense	$0.00		$0.00	$0.00	$0	Interest Expense - Unclassifed
6040	Allowance for Borrowed Funds Used During Construction--Credit	$0.00		$0.00	$0.00	$0	Interest Expense - Unclassifed
6042	Allowance For Other Funds Used During Construction	$0.00		$0.00	$0.00	$0	Interest Expense - Unclassifed
6045	Interest Expense on Capital Lease Obligations	$0.00		$0.00	$0.00	$0	Interest Expense - Unclassifed
6105	Taxes Other Than Income Taxes	$71,404.13		$0.00	$0.00	$71,404	Other Distribution Expenses
6110	Income Taxes	$91,000.00	($91,000)	$0.00	$2,984.21	$163,414	Income Tax Expense - Unclassified
6115	Provision for Future Income Taxes	$0.00		$0.00	$0.00	$0	Income Tax Expense - Unclassified
6205	Donations	$0.00		$0.00	$0.00	$0	Charitable Contributions
6210	Life Insurance	$0.00		$0.00	$0.00	$0	Insurance Expense (Working Capital)
6215	Penalties	$0.00		$0.00	$0.00	$0	Other Distribution Expenses
6225	Other Deductions	$0.00		$0.00	$0.00	$0	Other Distribution Expenses
6305	Extraordinary Income	$0.00		$0.00	$0.00	$0	Unclassified Expenses
6310	Extraordinary Deductions	$0.00		$0.00	$0.00	$0	Unclassified Expenses
6315	Income Taxes, Extraordinary Items	$0.00		$0.00	$0.00	$0	Unclassified Expenses
6405	Discontinues Operations - Income/ Gains	$0.00		$0.00	$0.00	$0	Unclassified Expenses
6410	Discontinued Operations - Deductions/ Losses	$0.00		$0.00	$0.00	$0	Unclassified Expenses
6415	Income Taxes, Discontinued Operations	$0.00		$0.00	$0.00	$0	Unclassified Expenses

$0

Reclassification Equals to Zero. O.K. to Proceed.

Asset Accounts Directly Allocated	$748,722
Income Statement Accounts Directly Allocated	$24,496

Grouped Accounts as per 2006 EDR	**Financial Statement (EDR Sheet 2.4, Column P**	**Reclassified Balance**
Land and Buildings	**$2,949,760**	**$2,949,760**
TS Primary Above 50	**$0**	**$0**
DS	**$2,942,645**	**$2,942,645**
Poles, Wires	**$26,350,429**	**$22,057,108**
Line Transformers	**$7,102,674**	**$7,102,674**
Services and Meters	**$2,402,778**	**$6,696,099**
General Plant	**$386,539**	**$386,539**
Equipment	**$3,048,327**	**$3,048,327**
IT Assets	**$2,729,351**	**$1,980,629**
CDM Expenditures and Recoveries	**$0**	**$0**
Other Distribution Assets	**$0**	**$0**
Contributions and Grants	**($2,197,180)**	**($2,197,180)**
Accumulated Amortization	**($16,720,273)**	**($16,720,273)**
Non-Distribution Asset	**$0**	**$0**
Unclassified Asset	**$0**	**$0**
Liability	**$0**	**$0**
Equity	**$0**	**($1,494,893)**
Sales of Electricity	**($25,661,601)**	**($25,661,601)**
Distribution Services Revenue	**($9,158,704)**	**($9,810,770)**
Late Payment Charges	**($71,821)**	**($71,821)**
Specific Service Charges	**($80,153)**	**($442,265)**
Other Distribution Revenue	**($40,000)**	**($40,000)**
Other Revenue - Unclassified	**$0**	**$0**
Other Income & Deductions	**$36,182**	**$36,182**
Power Supply Expenses (Working Capital)	**$26,499,812**	**$26,499,812**
Other Power Supply Expenses	**$0**	**$0**
Operation (Working Capital)	**$972,247**	**$1,010,650**
Maintenance (Working Capital)	**$1,080,566**	**$1,195,692**
Billing and Collection (Working Capital)	**$1,015,677**	**$1,069,977**
Community Relations (Working Capital)	**$0**	**$0**
Community Relations - CDM (Working Capital)	**$0**	**$0**
Administrative and General Expenses (Working Capital)	**$2,371,101**	**$2,209,453**
Insurance Expense (Working Capital)	**$100,616**	**$100,616**
Bad Debt Expense (Working Capital)	**$91,750**	**$91,750**
Advertising Expenses	**$6,402**	**$6,402**
Charitable Contributions	**$0**	**$0**
Amortization of Assets	**$1,684,651**	**$1,684,651**
Other Amortization - Unclassified	**$0**	**$0**
Interest Expense - Unclassifed	**$0**	**$1,177,975**
Income Tax Expense - Unclassified	**$91,000**	**$163,414**
Other Distribution Expenses	**$71,404**	**$71,404**
Non-Distribution Expenses	**$26,986**	**$26,986**
Unclassified Expenses	**$0**	**$0**
Total	**$28,031,167**	**$26,069,945**

2006 COST ALLOCATION INFORMATION FILING

Canadian Niagara Power Inc - Fort Erie & EOP

Monday, July 14, 2008

Sheet I4 Break Out Worksheet - Second Run

Instructions:
This is an input sheet for the Break Out of Distribution Assets, Contributed Capital, Amortization, and Amortization Expenses.
*****Please see Handbook for detailed instructions*****

Enter Net Fixed Assets from approved EDR, Sheet 3-1, cell F12	$28,995,051

RATE BASE AND DISTRIBUTION ASSETS		BALANCE SHEET ITEMS									EXPENSE ITEMS			
											5705	5710	5715	5720
Account	Description	Break out Functions	BREAK OUT (%)	BREAK OUT ($)	After BO	Contributed Capital - 1995	Accumulated Depreciation - 2105 Capital Contribution	Accumulated Depreciation - 2105 Fixed Assets Only	Accumulated Depreciation - 2120	Asset net of Accumulated Depreciation and Contributed Capital	Amortization Expense - Property, Plant, and Equipment	Amortization of Limited Term Electric Plant	Amortization of Intangibles and Other Electric Plant	Amortization of Electric Plant Acquisition Adjustments
1565	Conservation and Demand Management	$0		-	-	$0	$0	$0	$0	-	$0	$0	$0	$0
1805	Land	$0		$0	-									
1805-1	Land Station >50 kV			$0	-	$0	$0	$0	$0	-	$0	$0	$0	$0
1805-2	Land Station <50 kV		100.00%	$0	-	$0	$0	$0	$0	-	$0	$0	$0	$0
1806	Land Rights	$104,138		($104,138)	-									
1806-1	Land Rights Station >50 kV			$0	-	$0	$0	$0	$0	-	$0	$0	$0	$0
1806-2	Land Rights Station <50 kV		100.00%	$104,138	104,138	$0	$0	($52,687)	$0	51,451	$2,568	$0	$0	$0
1808	Buildings and Fixtures	$2,845,621		($2,845,621)	-									
1808-1	Buildings and Fixtures > 50 kV			$0	-	$0	$0	$0	$0	-	$0	$0	$0	$0
1808-2	Buildings and Fixtures < 50 KV		100.00%	$2,845,621	2,845,621	$0	$0	($126,744)	$0	2,718,877	($20,442)	$0	$0	$0
1810	Leasehold Improvements	$0		$0	-									
1810-1	Leasehold Improvements >50 kV			$0	-	$0	$0	$0	$0	-	$0	$0	$0	$0
1810-2	Leasehold Improvements <50 kV		100.00%	$0	-	$0	$0	$0	$0	-	$0	$0	$0	$0
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0		$0	-	$0	$0	$0	$0	-	$0	$0	$0	$0
1820	Distribution Station Equipment - Normally Primary below 50 kV	$2,942,645		($2,942,645)	-	$0	$0	$0	$0	-	$0	$0	$0	$0
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)		7.80%	$229,590	229,590	$0	$0	($63,416)	$0	166,174	$7,145	$0	$0	$0
1820-2	Distribution Station Equipment - Normally Primary below 50 kV Primary)		92.20%	$2,713,055	2,713,055	$0	$0	($1,072,303)	$0	1,640,752	$82,763	$0	$0	$0
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)		0.00%	$0	-	$0	$0	$0	$0	-	$0	$0	$0	$0
1825	Storage Battery Equipment	$0		$0	-									
1825-1	Storage Battery Equipment > 50 kV			$0	-	$0	$0	$0	$0	-	$0	$0	$0	$0
1825-2	Storage Battery Equipment <50 kV		100.00%	$0	-	$0	$0	$0	$0	-	$0	$0	$0	$0
1830	Poles, Towers and Fixtures	$9,701,516		($9,701,516)	-									
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery		0.27%	$26,530	26,530	($5,321)	$0	($15,373)	$0	5,836	$1,451	$0	$0	$0
1830-4	Poles, Towers and Fixtures - Primary		74.52%	$7,229,346	7,229,346	($359,342)	$0	($2,879,015)	$0	3,990,989	$294,015	$0	$0	$0
1830-5	Poles, Towers and Fixtures - Secondary		25.21%	$2,445,640	2,445,640	($121,132)	$0	($973,435)	$0	1,351,073	$99,423	$0	$0	$0
1835	Overhead Conductors and Devices	$8,103,087		($8,103,087)	-									
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery		0.07%	$5,658	5,658	($4,182)	$0	($4,342)	$0	- 2,866	$453	$0	$0	$0
1835-4	Overhead Conductors and Devices - Primary		74.65%	$6,049,294	6,049,294	($1,133,396)	$0	($2,591,735)	$0	2,324,163	$237,740	$0	$0	$0
1835-5	Overhead Conductors and Devices - Secondary		25.28%	$2,048,135	2,048,135	($383,418)	$0	($877,322)	$0	787,395	$80,471	$0	$0	$0
1840	Underground Conduit	$486,355		($486,355)	-									
1840-3	Underground Conduit - Bulk Delivery		0.00%	$0	-	$0	$0	$0	$0	-	$0	$0	$0	$0
1840-4	Underground Conduit - Primary		49.72%	$241,813	241,813	$0	$0	($70,301)	$0	171,512	$5,846	$0	$0	$0
1840-5	Underground Conduit - Secondary		50.28%	$244,542	244,542	$0	$0	($46,867)	$0	197,675	$3,897	$0	$0	$0
1845	Underground Conductors and Devices	$3,766,149		($3,766,149)	-									
1845-3	Underground Conductors and Devices - Bulk Delivery		0.00%	$0	-	$0	$0	$0	$0	-	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary		60.00%	$2,259,706	2,259,706	$0	$0	($885,198)	$0	1,374,508	$95,631	$0	$0	$0
1845-5	Underground Conductors and Devices - Secondary		40.00%	$1,506,443	1,506,443	$0	$0	($590,100)	$0	916,343	$63,752	$0	$0	$0
1850	Line Transformers	$7,102,674		$0	7,102,674	($140,013)	$0	($2,486,932)	$0	4,475,729	$207,619	$0	$0	$0
1855	Services	$4,293,321		$0	4,293,321	$0	$0	$0	$0	4,293,321	$0	$0	$0	$0
1860	Meters	$2,402,778		$0	2,402,778	($50,376)	$0	($1,191,354)	$0	1,161,048	$88,542	$0	$0	$0
	Total	**$41,748,286**		**-**	**$41,748,286**	**($2,197,180)**	**$0**	**($13,927,124)**	**$0**	**25,623,982**	**$1,250,874**	**$0**	**$0**	**$0**
	SUB TOTAL from I3	**$41,748,286**												

5705	5710	5715	5720

2006 COST ALLOCATION INFORMATION FILING

Canadian Niagara Power Inc - Fort Erie & EOP

Monday, July 14, 2008

Sheet I4 Break Out Worksheet - Second Run

Instructions:
This is an input sheet for the Break Out of Distribution Assets, Contributed Capital, Amortization, and Amortization Expenses.
*****Please see Handbook for detailed instructions*****

Enter Net Fixed Assets from approved EDR, Sheet 3-1, cell F12	$28,995,051

RATE BASE AND DISTRIBUTION ASSETS		BALANCE SHEET ITEMS									EXPENSE ITEMS			
											5705	5710	5715	5720
Account	**Description**	**Break out Functions**	**BREAK OUT (%)**	**BREAK OUT ($)**	**After BO**	**Contributed Capital - 1995**	**Accumulated Depreciation - 2105 Capital Contribution**	**Accumulated Depreciation - 2105 Fixed Assets Only**	**Accumulated Depreciation - 2120**	**Asset net of Accumulated Depreciation and Contributed Capital**	**Amortization Expense - Property, Plant, and Equipment**	**Amortization of Limited Term Electric Plant**	**Amortization of Intangibles and Other Electric Plant**	**Amortization of Electric Plant Acquisition Adjustments**
General Plant		**Break out Functions**				**Contributed Capital - 1995**	**Accumulated Depreciation - 2105 Capital Contribution**	**Accumulated Depreciation - 2105 Fixed Assets Only**	**Accumulated Depreciation - 2120**	**Net Asset**	**Amortization Expense - Property, Plant, and Equipment**	**Amortization of Limited Term Electric Plant**	**Amortization of Intangibles and Other Electric Plant**	**Amortization of Electric Plant Acquisition Adjustments**
1905	Land	$0			-	**$0**	**$0**	**$0**	**$0**	$ -	**$0**	**$0**	**$0**	**$0**
1906	Land Rights	$0			-	**$0**	**$0**	**$0**	**$0**	$ -	**$0**	**$0**	**$0**	**$0**
1908	Buildings and Fixtures	$386,539			386,539	**$0**	**$0**	**($57,480)**	**$0**	$ 329,059	**$7,247**	**$0**	**$0**	**$0**
1910	Leasehold Improvements	$0			-	**$0**	**$0**	**$0**	**$0**	$ -	**$0**	**$0**	**$0**	**$0**
1915	Office Furniture and Equipment	$1,150,790			1,150,790	**$0**	**$0**	**($651,777)**	**$0**	$ 499,013	**$100,611**	**$0**	**$0**	**$0**
1920	Computer Equipment - Hardware	$629,528			629,528	**$0**	**$0**	**($336,373)**	**$0**	$ 293,155	**$117,058**	**$0**	**$0**	**$0**
1925	Computer Software	$1,351,102			1,351,102	**$0**	**$0**	**($637,202)**	**$0**	$ 713,900	**$288,177**	**$0**	**$0**	**$0**
1930	Transportation Equipment	$413,247			413,247	**$0**	**$0**	**($538,213)**	**$0**	-$ 124,966	**($52,101)**	**$0**	**$0**	**$0**
1935	Stores Equipment	$96,772			96,772	**$0**	**$0**	**($38,564)**	**$0**	$ 58,208	**($2,571)**	**$0**	**$0**	**$0**
1940	Tools, Shop and Garage Equipment	$623,491			623,491	**$0**	**$0**	**($222,137)**	**$0**	$ 401,354	**($17,093)**	**$0**	**$0**	**$0**
1945	Measurement and Testing Equipment	$296,485			296,485	**$0**	**$0**	**($105,620)**	**$0**	$ 190,865	**($10,392)**	**$0**	**$0**	**$0**
1950	Power Operated Equipment	$66,375			66,375	**$0**	**$0**	**($22,787)**	**$0**	$ 43,588	**($970)**	**$0**	**$0**	**$0**
1955	Communication Equipment	$314,169			314,169	**$0**	**$0**	**($137,705)**	**$0**	$ 176,464	**($518)**	**$0**	**$0**	**$0**
1960	Miscellaneous Equipment	$86,998			86,998	**$0**	**$0**	**($33,349)**	**$0**	$ 53,649	**($1,417)**	**$0**	**$0**	**$0**
1970	Load Management Controls - Customer Premises	$0			-	**$0**	**$0**	**$0**	**$0**	$ -	**$0**	**$0**	**$0**	**$0**
1975	Load Management Controls - Utility Premises	$0			-	**$0**	**$0**	**$0**	**$0**	$ -	**$0**	**$0**	**$0**	**$0**
1980	System Supervisory Equipment	$0			-	**$0**	**$0**	**$0**	**$0**	$ -	**$0**	**$0**	**$0**	**$0**
1990	Other Tangible Property	$0			-	**$0**	**$0**	**$0**	**($11,941)**	-$ 11,941	**$0**	**$0**	**$5,746**	**$0**
2005	Property Under Capital Leases	$0			-	**$0**	**$0**	**$0**	**$0**	$ -	**$0**	**$0**	**$0**	**$0**
2010	Electric Plant Purchased or Sold	$0			-	**$0**	**$0**	**$0**	**$0**	$ -	**$0**	**$0**	**$0**	**$0**
	Total	$5,415,496		$0	$5,415,496	$0	$0	($2,781,207)	($11,941)	$2,622,348	$428,031	$0	$5,746	$0
	SUB TOTAL from I3	$5,415,496												
	I3 Directly Allocated	$748,722												
	Grand Total	$47,912,504		$0	$47,163,782	($2,197,180)	$0	($16,708,331)	($11,941)	$28,246,330	$1,678,905	$0	$5,746	$0

To be Prorated

1995	Contributed Capital - 1995	($2,197,180)
2105	Accumulated Depreciation - 2105	($16,708,331)
2120	Accumulated Depreciation - 2120	($11,941)
	Total	**($18,917,452)**
	Net Assets	**$28,995,052**

Net Fixed Assets Match EDR

Contributed Capital - 1995	Accumulated Depreciation - 2105 Capital Contribution	Accumulated Depreciation - 2105 Fixed Assets Only	Accumulated Depreciation - 2120	Asset net of Accumulated Depreciation and Contributed Capital
$2,197,180	**Balanced**			
		$16,708,331	**Balanced**	
			$11,941	**Balanced**

Amortization Expenses

5705	Amortization Expense - Property, Plant, and Equipment	$1,678,905
5710	Amortization of Limited Term Electric Plant	$0
5715	Amortization of Intangibles and Other Electric Plant	$5,746
5720	Amortization of Electric Plant Acquisition Adjustments	$0
	Total Amortization Expense	**$1,684,651**

5705	5710	5715	5720	
($1,678,905)	**Balanced**			
	$0	**Balanced**		
		($5,746)	**Balanced**	
			$0	**Balanced**

2006 COST ALLOCATION INFORMATION FILING

Canadian Niagara Power Inc - Fort Erie & EC

Monday, July 14, 2008

Sheet I5 Miscellaneous Data Worksheet - Second Run

kMs of Roads in Service Area Where Distribution Lines Exist	463.5
Deemed Equity Component of Rate Base (%)	50%

Instructions (Cont'd):

Step 3: Insert Approved Monthly Service Charge (Please refer to Approved EDR Sheet 8-5 column W)

Step 4: Insert Smart Meter Adder Included in Approved Monthly Service Charge (Please refer to Approved EDR Sheet 8-5 column T)

	1	2	3	7	8	9
	Residential	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
Step 3	18.94	20.97	908.07	1.55	1.84	
Step 4	0.27	0.27	0.27			

2006 COST ALLOCATION INFORMATION FILING

Canadian Niagara Power Inc - Fort Erie & EOP

Monday, July 14, 2008

Sheet I6 Customer Data Worksheet - Second Run

Total kWhs	390,326,569
Total kWs	469,424
Total Approved Distribution Revenue ($)	$9,810,769

	ID	Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
Billing Data								
kWh from approved EDR model, Sheet 7-1, Col M	CEN	390,326,569	141,540,950	56,958,341	188,076,527	2,471,714	880,875	398,162
kW from approved EDR model, Sheet 7-1, Col S	CDEM	469,424	-	-	460,009	6,889	2,526	-
kW, included in CDEM, from customers with line transformer allowance from approved EDR model, Sheet 6-3, Col P		255,882	-	-	255,882	-	-	-
Optional - kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-	-	-	-	-	-	-
KWh excluding KWh from Wholesale Market Participants	CEN EWMP	390,326,569	141,540,950	56,958,341	188,076,527	2,471,714	880,875	398,162
kWh - 30 year weather normalized amount		380,030,401	156,786,237	53,452,761	166,340,842	2,364,363	743,899	342,298
Approved Distribution Rev from approved EDR, Sheet 7-1, Col AK + Sheet 7-3 Col H	CREV	$9,810,770	4,795,124	1,533,243	3,366,004	70,045	26,508	19,846
Bad Debt 3 Year Historical Average from Approved EDR Model	BDHA	$72,902	$70,339	$2,563	$0	$0	$0	$0
Late Payment 3 Year Historical Average	LPHA	$514,114	246,806	83,922	177,496	3,673	1,245	972
Weighting Factor - Services			1.0	2.0	10.0	1.0	1.0	1.0
Weighting Factor - Billings			1.0	2.0	7.0	1.0	0.1	5.0
Number of Bills	CNB	224,508	201,468	18,468	2,004	228	948	1,392
Number of Connections (Unmetered)	CCON	3,039	-	-	-	2,448	475	116
Total Number of Customer from Approved EDR, Sheet 7-1, Col H excluding connections	CCA	18,624	16,789	1,539	167	19	79	31
Bulk Customer Base	CCB	3,560	3,072	389	34	11	45	9
Primary Customer Base	CCP	18,623	16,789	1,539	166	19	79	31
Line Transformer Customer Base	CCLT	18,605	16,789	1,539	148	19	79	31
Secondary Customer Base	CCS	18,605	16,789	1,539	148	19	79	31
Weighted - Services	CWCS	24,386	16,789	3,078	1,480	2,448	475	116
Weighted Meter -Capital	CWMC	1,862,630	1,144,300	239,230	479,100	-	-	-
Weighted Meter Reading	CWMR	29,452	23,111	4,644	1,697	-	-	-
Weighted Bills	CWNB	259,715	201,468	36,936	14,028	228	95	6,960
Data Mismatch Analysis								
Revenue with 30 year weather normalized kWh		9,833,932	5,311,604	1,438,877	2,977,001	67,003	22,386	17,062

Weather Normalized Data from Hydro

	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
kWh - 30 year weather normalized amount	397,264,661	163,896,444	55,876,827	173,884,347	2,471,586	777,635	357,821
2006 EDR Distribution Loss Factor		1.0453	1.0453	1.0453	1.0453	1.0453	1.0453

Bad Debt Data from EDR 2006

Sheet ADJ5 rows 26 - 32, column E	31,164	31,164	-	-	-	-	-
Sheet ADJ5 rows 26 - 32, column F	17,791	17,791	-	-	-	-	-
Sheet ADJ5 rows 26 - 32, column G	169,751	162,063	7,688	-	-	-	-
Three-year average	**72,902**	**70,339**	**2,563**	**-**	**-**	**-**	**-**

2006 COST ALLOCATION INFORMATION FILING
Canadian Niagara Power Inc - Fort Erie

Monday, July 14, 2008
Sheet I7.1 Meter Capital Worksheet - Second Run

		Residential			GS <50			GS>50-Regular			Street Light			Sentinel			Unmetered Scattered Load			TOTAL		
		1	2	3	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3
		Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs
	Allocation Percentage Weighted Factor			61.43%			13%			26%			0%			0%			0%			100%
	Cost Relative to Residential Average Cost			1.00			2.26			42.09			-			-			-			1.48
	Total	16789	1144300	68.15772232	1550	239230	154.3419355	167	479100	2868.862275	0	0	-	0	0	-	0	0	-	18506	1862630	100.6500594
Meter Types	**Cost per Meter (Installed)**																					
Single Phase 200 Amp - Urban	50	14,069	703450		1,027	51350			0			0			0			0		15,096	754800	
Single Phase 200 Amp - Rural	150	2,317	347550		0	0			0			0			0			0		2,317	347550	
Central Meter	250	105	26250		30	7500		0	0			0			0			0		135	33750	
Network Meter (Costs to be updated)	225	298	67050		0	0		0	0			0			0			0		298	67050	
Three-phase - No demand	210	0	0		228	47880		0	0			0			0			0		228	47880	
Smart Meters	300	0	0		0	0		0	0			0			0			0		0	0	
Demand without IT (usually three-phase)	500	0	0		265	132500		0	0		0	0		0	0		0	0		265	132500	
Demand with IT	2,100		0			0		141	296100		0	0		0	0		0	0		141	296100	
Demand with IT and Interval Capability - Secondary	2,300		0			0		10	23000		0	0		0	0		0	0		10	23000	
Demand with IT and Interval Capability - Primary	10,000		0			0		16	160000		0	0		0	0		0	0		16	160000	
Demand with IT and Interval Capability -Special (WMP)	40,000		0			0		0	0		0	0		0	0		0	0		0	0	
LDC Specific 1			0			0		0	0		0	0		0	0		0	0		0	0	
LDC Specific 2			0			0		0	0		0	0		0	0		0	0		0	0	
LDC Specific 3			0			0			0		0	0		0	0		0	0		0	0	

2006 COST ALLOCATION INFORMATION FILING
Canadian Niagara Power Inc - Fort Erie & EOF

Monday, July 14, 2008
Sheet I7.2 Meter Reading Worksheet - Second Run

Weighting Factors based on Contractor Pricing

Description		1			2			3		
		Residential			GS <50			GS>50-Regular		
		Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs
	Allocation Percentage Weighted Factor			78.47%			15.77%			5.76%
	Cost Relative to Residential Average Cost			1.00			2.18			7.38
	Total	16,789	23,111	1.38	1,548	4,644	3.00	167	1,697	10.16
	Factor									
Residential - Urban - Outside	1.00	12,784	12,784			0			0	
Residential - Urban - Outside with other services	1.00	0	0			0			0	
Residential - Urban - Inside	2.00	1,688	3,376			0			0	
Residential - Urban - Inside - with other services	1.00	0	0			0			0	
Residential - Rural - Outside	3.00	2,317	6,951			0			0	
Residential - Rural - Outside with other services	2.00	0	0			0			0	
LDC Specific 1		0	0		0	0		0	0	
LDC Specific 2		0	0		0	0		0	0	
GS - Walking	2.00		0		0	0		0	0	
GS - Walking - with other services	3.00		0		0	0		0	0	
GS - Vehicle with other services --- TOU Read	3.00		0		0	0		0	0	
GS - Vehicle with other services	3.00		0		1,548	4,644		141	423	
LDC Specific 3			0		0	0		0	0	
LDC Specific 4	0.00		0		0	0		0	0	
Interval	49.00		0		0	0		26	1,274	
LDC Specific 5			0		0	0		0	0	
LDC Specific 6			0		0	0		0	0	

Description	7			8			9					
	Street Light			Sentinel			Unmetered Scattered Load			TOTAL		
	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs
Allocation Percentage Weighted Factor			0.00%			0.00%			0.00%			100.00%
Cost Relative to Residential Average Cost			0.00			0.00			0.00			10.56
Total	-	-	0	-	-	0	-	-	0	18,504	29,452	15
Residential - Urban - Outside		0			0			0		12,784	12,784	
Residential - Urban - Outside with other services		0			0			0		-	-	
Residential - Urban - Inside		0			0			0		1,688	3,376	
Residential - Urban - Inside - with other services		0			0			0		-	-	
Residential - Rural - Outside		0			0			0		2,317	6,951	
Residential - Rural - Outside with other services		0			0			0		-	-	
LDC Specific 1	0	0		0	0		0	0		-	-	
LDC Specific 2	0	0		0	0		0	0		-	-	
GS - Walking	0	0		0	0		0	0		-	-	
GS - Walking - with other services	0	0		0	0		0	0		-	-	
GS - Vehicle with other services --- TOU Read	0	0		0	0		0	0		-	-	
GS - Vehicle with other services	0	0		0	0		0	0		1,689	5,067	
LDC Specific 3	0	0		0	0		0	0		-	-	
LDC Specific 4	0	0		0	0		0	0		-	-	
Interval	0	0		0	0		0	0		26	1,274	
LDC Specific 5	0	0		0	0		0	0		-	-	
LDC Specific 6	0	0		0	0		0	0		-	-	

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2006 COST ALLOCATION INFORMATION FILING

Canadian Niagara Power Inc - Fort Erie & EOP

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Sheet I8 Demand Data Worksheet - Second Run

This is an input sheet for demand allocators.

CP TEST RESULTS	**12 CP**
NCP TEST RESULTS	**4 NCP**

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

			1	2	3	7	8	9
Customer Classes		**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
CO-INCIDENT PEAK								
1 CP								
Transformation CP	TCP1	71,845	33,933	8,441	29,392	24	7	47
Bulk Delivery CP	BCP1	68,988	32,593	8,104	28,215	23	7	45
Total Sytem CP	DCP1	68,988	32,593	8,104	28,215	23	7	45
4 CP								
Transformation CP	TCP4	279,544	141,643	30,138	106,901	528	164	170
Bulk Delivery CP	BCP4	268,417	136,019	28,933	102,638	507	157	163
Total Sytem CP	DCP4	268,417	136,019	28,933	102,638	507	157	163
12 CP								
Transformation CP	TCP12	755,611	358,422	86,801	306,490	2,575	814	509
Bulk Delivery CP	BCP12	725,476	344,108	83,330	294,301	2,469	781	489
Total Sytem CP	DCP12	725,476	344,108	83,330	294,301	2,469	781	489
NON CO_INCIDENT PEAK								
1 NCP								
Classification NCP from Load Data Provider	DNCP1	80,039	37,920	10,045	31,197	626	203	48
Primary NCP	PNCP1	79,797	37,920	10,045	30,955	626	203	48
Line Transformer NCP	LTNCP1	76,410	37,920	10,045	27,568	626	203	48
Secondary NCP	SNCP1	76,410	37,920	10,045	27,568	626	203	48
4 NCP								
Classification NCP from Load Data Provider	DNCP4	304,782	146,322	36,367	118,609	2,500	805	179
Primary NCP	PNCP4	303,872	146,322	36,367	117,699	2,500	805	179
Line Transformer NCP	LTNCP4	290,998	146,322	36,367	104,825	2,500	805	179
Secondary NCP	SNCP4	290,998	146,322	36,367	104,825	2,500	805	179
12 NCP								
Classification NCP from Load Data Provider	DNCP12	813,467	371,505	97,876	333,745	7,498	2,355	489
Primary NCP	PNCP12	810,851	371,505	97,876	331,129	7,498	2,355	489
Line Transformer NCP	LTNCP12	774,605	371,505	97,876	294,883	7,498	2,355	489
Secondary NCP	SNCP12	774,605	371,505	97,876	294,883	7,498	2,355	489

2006 COST ALLOCATION INFORMATION FILING

Canadian Niagara Power Inc - Fort Erie & EOP

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Monday, July 14, 2008

Sheet I9 Direct Allocation Worksheet - Second Run

USoA Account #	Accounts	Direct Allocation	Total Allocated to Rate Classifications?	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 etered Scattered Load

Instructions:
To Allocate Capital Contributions by Rate Classification, Input Allocation on Next Line

1995	Contributions and Grants - Credit	$0	Yes	$0	$0	$0	$0	$0	$0

Instructions:
The Following is Used to Allocate Directly Allocated Costs from I3 to Rate Classifications

USoA Account #	Accounts	Direct Allocation	Total Allocated to Rate Classifications?	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	etered Scattered Load
1805	Land	$0	Yes	$0	$0	$0	$0	$0	$0
1806	Land Rights	$0	Yes	$0	$0	$0	$0	$0	$0
1808	Buildings and Fixtures	$0	Yes	$0	$0	$0	$0	$0	$0
1810	Leasehold Improvements	$0	Yes	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	Yes	$0	$0	$0	$0	$0	$0
1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	Yes	$0	$0	$0	$0	$0	$0
1825	Storage Battery Equipment	$0	Yes	$0	$0	$0	$0	$0	$0
1830	Poles, Towers and Fixtures	$0	Yes	$0	$0	$0	$0	$0	$0
1835	Overhead Conductors and Devices	$0	Yes	$0	$0	$0	$0	$0	$0
1840	Underground Conduit	$0	Yes	$0	$0	$0	$0	$0	$0
1845	Underground Conductors and Devices	$0	Yes	$0	$0	$0	$0	$0	$0
1850	Line Transformers	$0	Yes	$0	$0	$0	$0	$0	$0
1855	Services	$0	Yes	$0	$0	$0	$0	$0	$0
1860	Meters	$0	Yes	$0	$0	$0	$0	$0	$0
1905	Land	$0	Yes	$0	$0	$0	$0	$0	$0
1906	Land Rights	$0	Yes	$0	$0	$0	$0	$0	$0
1908	Buildings and Fixtures	$0	Yes	$0	$0	$0	$0	$0	$0
1910	Leasehold Improvements	$0	Yes	$0	$0	$0	$0	$0	$0
1915	Office Furniture and Equipment	$0	Yes	$0	$0	$0	$0	$0	$0
1920	Computer Equipment - Hardware	$149,582	Yes	$116,673	$20,460	$8,018	$106	$43	$4,283
1925	Computer Software	$599,140	Yes	$460,786	$90,347	$32,762	$754	$306	$14,187
1930	Transportation Equipment	$0	Yes	$0	$0	$0	$0	$0	$0
1935	Stores Equipment	$0	Yes	$0	$0	$0	$0	$0	$0
1940	Tools, Shop and Garage Equipment	$0	Yes	$0	$0	$0	$0	$0	$0
1945	Measurement and Testing Equipment	$0	Yes	$0	$0	$0	$0	$0	$0
1950	Power Operated Equipment	$0	Yes	$0	$0	$0	$0	$0	$0
1955	Communication Equipment	$0	Yes	$0	$0	$0	$0	$0	$0
1960	Miscellaneous Equipment	$0	Yes	$0	$0	$0	$0	$0	$0
1970	Load Management Controls - Customer Premises	$0	Yes	$0	$0	$0	$0	$0	$0
1975	Load Management Controls - Utility Premises	$0	Yes	$0	$0	$0	$0	$0	$0
1980	System Supervisory Equipment	$0	Yes	$0	$0	$0	$0	$0	$0
1990	Other Tangible Property	$0	Yes	$0	$0	$0	$0	$0	$0
2005	Property Under Capital Leases	$0	Yes	$0	$0	$0	$0	$0	$0
2010	Electric Plant Purchased or Sold	$0	Yes	$0	$0	$0	$0	$0	$0
2050	Completed Construction Not Classified--Electric	$0	Yes	$0	$0	$0	$0	$0	$0
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	$0	Yes	$0	$0	$0	$0	$0	$0
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	$0	Yes	$0	$0	$0	$0	$0	$0
	Directly Allocated Net Fixed Assets			**$577,458**	**$110,806**	**$40,780**	**$860**	**$348**	**$18,470**
5005	Operation Supervision and Engineering	$0	Yes	$0	$0	$0	$0	$0	$0
5010	Load Dispatching	$0	Yes	$0	$0	$0	$0	$0	$0
5012	Station Buildings and Fixtures Expense	$0	Yes	$0	$0	$0	$0	$0	$0
5014	Transformer Station Equipment - Operation Labour	$0	Yes	$0	$0	$0	$0	$0	$0
5015	Transformer Station Equipment - Operation Supplies and Expenses	$0	Yes	$0	$0	$0	$0	$0	$0
5016	Distribution Station Equipment - Operation Labour	$0	Yes	$0	$0	$0	$0	$0	$0
5017	Distribution Station Equipment - Operation Supplies and Expenses	$0	Yes	$0	$0	$0	$0	$0	$0
5020	Overhead Distribution Lines and Feeders - Operation Labour	$0	Yes	$0	$0	$0	$0	$0	$0
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$0	Yes	$0	$0	$0	$0	$0	$0
5030	Overhead Subtransmission Feeders - Operation	$0	Yes	$0	$0	$0	$0	$0	$0
5035	Overhead Distribution Transformers- Operation	$0	Yes	$0	$0	$0	$0	$0	$0
5040	Underground Distribution Lines and Feeders - Operation Labour	$0	Yes	$0	$0	$0	$0	$0	$0

5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$0	Yes	$0	$0	$0	$0	$0	$0
5050	Underground Subtransmission Feeders - Operation	$0	Yes	$0	$0	$0	$0	$0	$0
5055	Underground Distribution Transformers - Operation	$0	Yes	$0	$0	$0	$0	$0	$0
5065	Meter Expense	$0	Yes	$0	$0	$0	$0	$0	$0
5070	Customer Premises - Operation Labour	$0	Yes	$0	$0	$0	$0	$0	$0
5075	Customer Premises - Materials and Expenses	$0	Yes	$0	$0	$0	$0	$0	$0
5085	Miscellaneous Distribution Expense	$0	Yes	$0	$0	$0	$0	$0	$0
5090	Underground Distribution Lines and Feeders - Rental Paid	$0	Yes	$0	$0	$0	$0	$0	$0
5095	Overhead Distribution Lines and Feeders - Rental Paid	$0	Yes	$0	$0	$0	$0	$0	$0
5096	Other Rent	$0	Yes	$0	$0	$0	$0	$0	$0
5105	Maintenance Supervision and Engineering	$0	Yes	$0	$0	$0	$0	$0	$0
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$0	Yes	$0	$0	$0	$0	$0	$0
5112	Maintenance of Transformer Station Equipment	$0	Yes	$0	$0	$0	$0	$0	$0
5114	Maintenance of Distribution Station Equipment	$0	Yes	$0	$0	$0	$0	$0	$0
5120	Maintenance of Poles, Towers and Fixtures	$0	Yes	$0	$0	$0	$0	$0	$0
5125	Maintenance of Overhead Conductors and Devices	$0	Yes	$0	$0	$0	$0	$0	$0
5130	Maintenance of Overhead Services	$0	Yes	$0	$0	$0	$0	$0	$0
5135	Overhead Distribution Lines and Feeders - Right of Way	$0	Yes	$0	$0	$0	$0	$0	$0
5145	Maintenance of Underground Conduit	$0	Yes	$0	$0	$0	$0	$0	$0
5150	Maintenance of Underground Conductors and Devices	$0	Yes	$0	$0	$0	$0	$0	$0
5155	Maintenance of Underground Services	$0	Yes	$0	$0	$0	$0	$0	$0
5160	Maintenance of Line Transformers	$0	Yes	$0	$0	$0	$0	$0	$0
5175	Maintenance of Meters	$0	Yes	$0	$0	$0	$0	$0	$0
5305	Supervision	$0	Yes	$0	$0	$0	$0	$0	$0
5310	Meter Reading Expense	$0	Yes	$0	$0	$0	$0	$0	$0
5315	Customer Billing	$0	Yes	$0	$0	$0	$0	$0	$0
5320	Collecting	$0	Yes	$0	$0	$0	$0	$0	$0
5325	Collecting- Cash Over and Short	$0	Yes	$0	$0	$0	$0	$0	$0
5330	Collection Charges	$0	Yes	$0	$0	$0	$0	$0	$0
5335	Bad Debt Expense	$0	Yes	$0	$0	$0	$0	$0	$0
5340	Miscellaneous Customer Accounts Expenses	$0	Yes	$0	$0	$0	$0	$0	$0
5405	Supervision	$0	Yes	$0	$0	$0	$0	$0	$0
5410	Community Relations - Sundry	$0	Yes	$0	$0	$0	$0	$0	$0
5415	Energy Conservation	$0	Yes	$0	$0	$0	$0	$0	$0
5420	Community Safety Program	$0	Yes	$0	$0	$0	$0	$0	$0
5425	Miscellaneous Customer Service and Informational Expenses	$0	Yes	$0	$0	$0	$0	$0	$0
5505	Supervision	$0	Yes	$0	$0	$0	$0	$0	$0
5510	Demonstrating and Selling Expense	$0	Yes	$0	$0	$0	$0	$0	$0
5515	Advertising Expense	$0	Yes	$0	$0	$0	$0	$0	$0
5520	Miscellaneous Sales Expense	$0	Yes	$0	$0	$0	$0	$0	$0
5605	Executive Salaries and Expenses	$0	Yes	$0	$0	$0	$0	$0	$0
5610	Management Salaries and Expenses	$0	Yes	$0	$0	$0	$0	$0	$0
5615	General Administrative Salaries and Expenses	$0	Yes	$0	$0	$0	$0	$0	$0
5620	Office Supplies and Expenses	$0	Yes	$0	$0	$0	$0	$0	$0
5625	Administrative Expense Transferred Credit	$0	Yes	$0	$0	$0	$0	$0	$0
5630	Outside Services Employed	$0	Yes	$0	$0	$0	$0	$0	$0
5635	Property Insurance	$0	Yes	$0	$0	$0	$0	$0	$0
5640	Injuries and Damages	$0	Yes	$0	$0	$0	$0	$0	$0
5645	Employee Pensions and Benefits	$0	Yes	$0	$0	$0	$0	$0	$0
5650	Franchise Requirements	$0	Yes	$0	$0	$0	$0	$0	$0
5655	Regulatory Expenses	$0	Yes	$0	$0	$0	$0	$0	$0
5660	General Advertising Expenses	$0	Yes	$0	$0	$0	$0	$0	$0
5665	Miscellaneous General Expenses	$0	Yes	$0	$0	$0	$0	$0	$0
5670	Rent	$0	Yes	$0	$0	$0	$0	$0	$0
5675	Maintenance of General Plant	$0	Yes	$0	$0	$0	$0	$0	$0
5680	Electrical Safety Authority Fees	$0	Yes	$0	$0	$0	$0	$0	$0
5705	Amortization Expense - Property, Plant, and Equipment	$0	Yes	$0	$0	$0	$0	$0	$0
5710	Amortization of Limited Term Electric Plant	$0	Yes	$0	$0	$0	$0	$0	$0
5715	Amortization of Intangibles and Other Electric Plant	$0	Yes	$0	$0	$0	$0	$0	$0
5720	Amortization of Electric Plant Acquisition Adjustments	$0	Yes	$0	$0	$0	$0	$0	$0
6105	Taxes Other Than Income Taxes	$0	Yes	$0	$0	$0	$0	$0	$0
6205	Donations	$0	Yes	$0	$0	$0	$0	$0	$0
6210	Life Insurance	$0	Yes	$0	$0	$0	$0	$0	$0
6215	Penalties	$0	Yes	$0	$0	$0	$0	$0	$0
6225	Other Deductions	$0	Yes	$0	$0	$0	$0	$0	$0
	Total Expenses			$0	$0	$0	$0	$0	$0
	Depreciation Expense			$0	$0	$0	$0	$0	$0

Total Net Fixed Assets Excluding Gen Plant	**$41,748,286**	**Allocated**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**etered Scattered Load**
Approved Total PILs	**$166,398**	**$2,984**	$2,302	$442	$163	$3	$1	$74
Approved Total Return on Debt	**$1,199,487**	**$21,512**	$16,591	$3,184	$1,172	$25	$10	$531
Approved Total Return on Equity	**$1,522,192**	**$27,299**	$21,055	$4,040	$1,487	$31	$13	$673

Total	$39,948	$7,665	$2,821	$59	$24	$1,278

2006 COST ALLOCATION INFORMATION FILING
Canadian Niagara Power Inc - Fort Erie & EOP

Ontario

Monday, July 14, 2008

Sheet O1 Revenue to Cost Summary Worksheet - Second Run

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
crev	Distribution Revenue (sale)	$9,810,770	$4,795,124	$1,533,243	$3,366,004	$70,045	$26,508	$19,846
mi	Miscellaneous Revenue (mi)	$517,904	$381,047	$75,246	$48,355	$785	$314	$12,157
	Total Revenue	**$10,328,674**	**$5,176,171**	**$1,608,488**	**$3,414,359**	**$70,830**	**$26,822**	**$32,003**
	Expenses							
di	Distribution Costs (di)	$1,967,062	$1,143,638	$218,050	$488,558	$93,868	$18,428	$4,519
cu	Customer Related Costs (cu)	$1,401,008	$1,069,609	$189,261	$117,387	$2,016	$552	$22,182
ad	General and Administration (ad)	$2,387,875	$1,555,981	$287,247	$441,901	$70,799	$14,005	$17,942
dep	Depreciation and Amortization (dep)	$1,684,651	$972,184	$183,806	$442,898	$68,931	$13,547	$3,285
INPUT	PILs (INPUT)	$163,414	$94,885	$18,365	$41,028	$7,335	$1,443	$357
INT	Interest	$1,177,975	$683,984	$132,385	$295,753	$52,877	$10,402	$2,575
	Total Expenses	**$8,781,985**	**$5,520,282**	**$1,029,115**	**$1,827,525**	**$295,826**	**$58,377**	**$50,860**
	Direct Allocation	**$51,795**	**$39,948**	**$7,665**	**$2,821**	**$59**	**$24**	**$1,278**
NI	Allocated Net Income (NI)	$1,494,893	$868,000	$168,001	$375,322	$67,102	$13,200	$3,268
	Revenue Requirement (includes NI)	$10,328,673	$6,428,230	$1,204,782	$2,205,668	$362,988	$71,601	$55,406
		Revenue Requirement Input equals Output						
	Rate Base Calculation							
	Net Assets							
dp	Distribution Plant - Gross	$41,748,286	$24,123,751	$4,629,707	$10,794,872	$1,766,983	$347,598	$85,376
gp	General Plant - Gross	$5,415,496	$3,144,576	$605,633	$1,362,907	$242,821	$47,758	$11,800
accum dep	Accumulated Depreciation	($16,720,272)	($9,590,920)	($1,830,739)	($4,496,120)	($644,772)	($126,882)	($30,839)
co	Capital Contribution	($2,197,180)	($1,276,304)	($231,620)	($568,304)	($97,249)	($19,089)	($4,613)
	Total Net Plant	**$28,246,330**	**$16,401,103**	**$3,172,981**	**$7,093,354**	**$1,267,783**	**$249,385**	**$61,724**
	Directly Allocated Net Fixed Assets	**$748,722**	**$577,458**	**$110,806**	**$40,780**	**$860**	**$348**	**$18,470**
COP	Cost of Power (COP)	$26,499,812	$9,609,412	$3,866,981	$12,768,776	$167,808	$59,804	$27,032
	OM&A Expenses	$5,755,945	$3,769,229	$694,559	$1,047,846	$166,683	$32,985	$44,643
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0
	Subtotal	***$32,255,758***	***$13,378,641***	***$4,561,539***	***$13,816,622***	***$334,491***	***$92,789***	***$71,675***
	Working Capital	**$4,838,364**	**$2,006,796**	**$684,231**	**$2,072,493**	**$50,174**	**$13,918**	**$10,751**
	Total Rate Base	**$33,833,415**	**$18,985,357**	**$3,968,018**	**$9,206,628**	**$1,318,816**	**$263,652**	**$90,945**
		Rate Base Input equals Output						
	Equity Component of Rate Base	**$16,916,708**	**$9,492,678**	**$1,984,009**	**$4,603,314**	**$659,408**	**$131,826**	**$45,472**
	Net Income on Allocated Assets	**$1,494,893**	**($384,058)**	**$571,708**	**$1,584,013**	**($225,055)**	**($31,579)**	**($20,135)**
	Net Income on Direct Allocation Assets	**$27,299**	**$21,055**	**$4,040**	**$1,487**	**$31**	**$13**	**$673**
	Net Income	**$1,522,193**	**($363,003)**	**$575,748**	**$1,585,500**	**($225,024)**	**($31,566)**	**($19,461)**
	RATIOS ANALYSIS							
	REVENUE TO EXPENSES %	100.00%	80.52%	133.51%	154.80%	19.51%	37.46%	57.76%
	EXISTING REVENUE MINUS ALLOCATED COSTS	$1	($1,252,058)	$403,707	$1,208,691	($292,158)	($44,779)	($23,402)
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.00%	-3.82%	29.02%	34.44%	-34.13%	-23.95%	-42.80%

Canadian Niagara Power Inc - Fort Erie & EOP

Monday, July 14, 2008

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - Second Run

Output sheet showing minimum and maximum level for Monthly Fixed Charge

	1	2	3	7	8	9
Summary	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
Customer Unit Cost per month - Avoided Cost	$3.81	$7.52	$46.31	-$0.16	-$0.16	$8.62
Customer Unit Cost per month - Directly Related	$6.36	$12.91	$86.09	-$0.12	-$0.11	$14.71
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$18.17	$28.57	$129.61	$12.05	$6.58	$29.66
Fixed Charge per approved 2006 EDR	$18.94	$20.97	$908.07	$1.55	$1.84	$0.00

		1	2	3	7	8	9
Information to be Used to Allocate PILs, ROD, ROE and A&G	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
General Plant - Gross Assets	$5,415,496	$3,144,576	$605,633	$1,362,907	$242,821	$47,758	$11,800
General Plant - Accumulated Depreciation	($2,793,148)	($1,621,876)	($312,367)	($702,946)	($125,240)	($24,632)	($6,086)
General Plant - Net Fixed Assets	$2,622,348	$1,522,699	$293,266	$659,961	$117,581	$23,126	$5,714
General Plant - Depreciation	$433,777	$251,878	$48,511	$109,168	$19,450	$3,825	$945
Total Net Fixed Assets Excluding General Plant	$25,623,982	$14,878,403	$2,879,715	$6,433,393	$1,150,202	$226,259	$56,010
Total Administration and General Expense	$2,387,875	$1,555,981	$287,247	$441,901	$70,799	$14,005	$17,942
Total O&M	$3,365,935	$2,211,845	$407,053	$605,561	$95,823	$18,968	$26,684

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

			1	2	3	7	8	9	
USoA Account #	Accounts	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	
	Distribution Plant								
1860	Meters	$2,402,778	$1,476,138	$308,605	$618,035	$0	$0	$0	CWMC
	Accumulated Amortization								
	Accum. Amortization of Electric Utility Plant - Meters only	($1,241,730)	($762,852)	($159,484)	($319,394)	$0	$0	$0	
	Meter Net Fixed Assets	**$1,161,048**	**$713,286**	**$149,121**	**$298,641**	**$0**	**$0**	**$0**	
	Misc Revenue								
4082	Retail Services Revenues	($6,455)	($5,007)	($918)	($349)	($6)	($2)	($173)	CWNB
4084	Service Transaction Requests (STR) Revenues	($80)	($62)	($11)	($4)	($0)	($0)	($2)	CWNB
4090	Electric Services Incidental to Energy Sales	$0	$0	$0	$0	$0	$0	$0	CWNB
4220	Other Electric Revenues	($133,181)	($77,331)	($14,967)	($33,438)	($5,978)	($1,176)	($291)	NFA
4225	Late Payment Charges	($71,821)	($34,479)	($11,724)	($24,796)	($513)	($174)	($136)	LPHA
	Sub-total	*($211,537)*	*($116,879)*	*($27,621)*	*($58,587)*	*($6,497)*	*($1,352)*	*($602)*	
	Operation								
5065	Meter Expense	$154,933	$95,183	$19,899	$39,851	$0	$0	$0	CWMC
5070	Customer Premises - Operation Labour	$1,955	$1,524	$140	$15	$222	$43	$11	CCA
5075	Customer Premises - Materials and Expenses	$9,406	$7,334	$672	$73	$1,069	$207	$51	CCA
	Sub-total	*$166,294*	*$104,040*	*$20,711*	*$39,940*	*$1,292*	*$251*	*$61*	
	Maintenance								
5175	Maintenance of Meters	$72,986	$44,839	$9,374	$18,773	$0	$0	$0	1860
	Billing and Collection								
5310	Meter Reading Expense	$244,533	$191,885	$38,558	$14,090	$0	$0	$0	CWMR
5315	Customer Billing	$348,370	$270,240	$49,544	$18,817	$306	$127	$9,336	CWNB
5320	Collecting	$114,921	$89,148	$16,344	$6,207	$101	$42	$3,080	CWNB
5325	Collecting- Cash Over and Short	$626	$485	$89	$34	$1	$0	$17	CWNB
5330	Collection Charges	$4,262	$3,306	$606	$230	$4	$2	$114	CWNB
	Sub-total	$712,712	$555,065	$105,141	$39,378	$411	$171	$12,547	
	Total Operation, Maintenance and Billing	$951,992	$703,944	$135,226	$98,090	$1,703	$422	$12,608	
	Amortization Expense - Meters	$88,542	$54,395	$11,372	$22,775	$0	$0	$0	
	Allocated PILs	$6,717	$4,127	$863	$1,727	$0	$0	$0	
	Allocated Debt Return	$48,420	$29,747	$6,222	$12,452	$0	$0	$0	
	Allocated Equity Return	$61,447	$37,749	$7,896	$15,802	$0	$0	$0	
	Total	**$945,581**	**$713,083**	**$133,958**	**$92,259**	**($4,794)**	**($931)**	**$12,006**	

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

			1	2	3	7	8	9	
USoA Account #	Accounts	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	
	Distribution Plant								
1860	Meters	$2,402,778	$1,476,138	$308,605	$618,035	$0	$0	$0	CWMC
	Accumulated Amortization								
	Accum. Amortization of Electric Utility Plant - Meters only	($1,241,730)	($762,852)	($159,484)	($319,394)	$0	$0	$0	
	Meter Net Fixed Assets	$1,161,048	$713,286	$149,121	$298,641	$0	$0	$0	
	Allocated General Plant Net Fixed Assets	$118,822	$73,000	$15,186	$30,636	$0	$0	$0	
	Meter Net Fixed Assets Including General Plant	$1,279,870	$786,285	$164,307	$329,277	$0	$0	$0	
	Misc Revenue								
4082	Retail Services Revenues	($6,455)	($5,007)	($918)	($349)	($6)	($2)	($173)	CWNB

USoA Account #	Accounts	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	
4084	Service Transaction Requests (STR) Revenues	($80)	($62)	($11)	($4)	($0)	($0)	($2)	CWNB
4090	Electric Services Incidental to Energy Sales	$0	$0	$0	$0	$0	$0	$0	CWNB
4220	Other Electric Revenues	($133,181)	($77,331)	($14,967)	($33,438)	($5,978)	($1,176)	($291)	NFA
4225	Late Payment Charges	($71,821)	($34,479)	($11,724)	($24,796)	($513)	($174)	($136)	LPHA
	Sub-total	*($211,537)*	*($116,879)*	*($27,621)*	*($58,587)*	*($6,497)*	*($1,352)*	*($602)*	
	Operation								
5065	Meter Expense	$154,933	$95,183	$19,899	$39,851	$0	$0	$0	CWMC
5070	Customer Premises - Operation Labour	$1,955	$1,524	$140	$15	$222	$43	$11	CCA
5075	Customer Premises - Materials and Expenses	$9,406	$7,334	$672	$73	$1,069	$207	$51	CCA
	Sub-total	*$166,294*	*$104,040*	*$20,711*	*$39,940*	*$1,292*	*$251*	*$61*	
	Maintenance								
5175	Maintenance of Meters	$72,986	$44,839	$9,374	$18,773	$0	$0	$0	1860
	Billing and Collection								
5310	Meter Reading Expense	$244,533	$191,885	$38,558	$14,090	$0	$0	$0	CWMR
5315	Customer Billing	$348,370	$270,240	$49,544	$18,817	$306	$127	$9,336	CWNB
5320	Collecting	$114,921	$89,148	$16,344	$6,207	$101	$42	$3,080	CWNB
5325	Collecting- Cash Over and Short	$626	$485	$89	$34	$1	$0	$17	CWNB
5330	Collection Charges	$4,262	$3,306	$606	$230	$4	$2	$114	CWNB
	Sub-total	*$712,712*	*$555,065*	*$105,141*	*$39,378*	*$411*	*$171*	*$12,547*	
	Total Operation, Maintenance and Billing	$951,992	$703,944	$135,226	$98,090	$1,703	$422	$12,608	
	Amortization Expense - Meters	$88,542	$54,395	$11,372	$22,775	$0	$0	$0	
	Amortization Expense - General Plant assigned to Meters	*$19,655*	*$12,075*	*$2,512*	*$5,068*	*$0*	*$0*	*$0*	
	Admin and General	$672,261	$495,208	$95,426	$71,580	$1,258	$311	$8,477	
	Allocated PILs	$7,404	$4,549	$951	$1,905	$0	$0	$0	
	Allocated Debt Return	$53,375	$32,791	$6,855	$13,729	$0	$0	$0	
	Allocated Equity Return	$67,735	$41,613	$8,700	$17,423	$0	$0	$0	
	Total	**$1,649,427**	**$1,227,696**	**$233,422**	**$171,982**	**($3,537)**	**($620)**	**$20,483**	

Scenario 3

Minimum System Customer Costs Adjusted for PLCC - High Limit Fixed Customer Charge

			1	2	3	7	8	9	
USoA Account #	**Accounts**	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	
	Distribution Plant								
1565	Conservation and Demand Management Expenditures and Recoveries	$0	$0	$0	$0	$0	$0	$0	CDMPP
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	#N/A
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	BCP
1830-4	Poles, Towers and Fixtures - Primary	$2,891,739	$2,254,651	$206,677	$22,293	$328,750	$63,789	$15,578	PNCP
1830-5	Poles, Towers and Fixtures - Secondary	$978,256	$763,372	$69,976	$6,729	$111,307	$21,598	$5,274	SNCP
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	#N/A
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	BCP
1835-4	Overhead Conductors and Devices - Primary	$2,419,718	$1,886,622	$172,941	$18,654	$275,088	$53,377	$13,035	PNCP
1835-5	Overhead Conductors and Devices - Secondary	$819,254	$639,296	$58,602	$5,636	$93,216	$18,087	$4,417	SNCP
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	#N/A
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	BCP
1840-4	Underground Conduit - Primary	$96,725	$75,415	$6,913	$746	$10,996	$2,134	$521	PNCP
1840-5	Underground Conduit - Secondary	$97,817	$76,330	$6,997	$673	$11,130	$2,160	$527	SNCP
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	#N/A
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	BCP
1845-4	Underground Conductors and Devices - Primary	$903,882	$704,745	$64,602	$6,968	$102,759	$19,939	$4,869	PNCP
1845-5	Underground Conductors and Devices - Secondary	$602,577	$470,215	$43,103	$4,145	$68,562	$13,303	$3,249	SNCP
1850	Line Transformers	$2,841,070	$2,216,998	$203,226	$19,543	$323,260	$62,724	$15,318	LTNCP
1855	Services	$4,293,321	$2,955,818	$541,903	$260,564	$430,987	$83,627	$20,423	CWCS
1860	Meters	$2,402,778	$1,476,138	$308,605	$618,035	$0	$0	$0	CWMC
	Sub-total	*$18,347,137*	*$13,519,601*	*$1,683,546*	*$963,986*	*$1,756,054*	*$340,738*	*$83,212*	
	Accumulated Amortization								
	Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	($6,657,012)	($4,986,544)	($546,657)	($359,275)	($615,855)	($119,498)	($29,183)	
	Customer Related Net Fixed Assets	$11,690,125	$8,533,057	$1,136,889	$604,711	$1,140,199	$221,240	$54,029	
	Allocated General Plant Net Fixed Assets	$1,195,794	$873,298	$115,779	$62,033	$116,559	$22,613	$5,512	
	Customer Related NFA Including General Plant	$12,885,919	$9,406,355	$1,252,668	$666,745	$1,256,758	$243,852	$59,541	
	Misc Revenue								
4082	Retail Services Revenues	($6,455)	($5,007)	($918)	($349)	($6)	($2)	($173)	CWNB
4084	Service Transaction Requests (STR) Revenues	($80)	($62)	($11)	($4)	($0)	($0)	($2)	CWNB
4090	Electric Services Incidental to Energy Sales	$0	$0	$0	$0	$0	$0	$0	CWNB
4220	Other Electric Revenues	($133,181)	($77,331)	($14,967)	($33,438)	($5,978)	($1,176)	($291)	NFA
4225	Late Payment Charges	($71,821)	($34,479)	($11,724)	($24,796)	($513)	($174)	($136)	LPHA
4235	Miscellaneous Service Revenues	($442,265)	($343,077)	($62,898)	($23,888)	($388)	($161)	($11,852)	CWNB
	Sub-total	*($653,802)*	*($459,956)*	*($90,518)*	*($82,475)*	*($6,885)*	*($1,514)*	*($12,454)*	
	Operating and Maintenance								
5005	Operation Supervision and Engineering	$5,619	$4,244	$485	$122	$619	$120	$29	1815-1855
5010	Load Dispatching	$58,038	$43,839	$5,005	$1,259	$6,392	$1,240	$303	1815-1855
5020	Overhead Distribution Lines and Feeders - Operation Labour	$19,210	$14,981	$1,373	$144	$2,184	$424	$104	1830 & 1835
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$8,894	$6,936	$636	$67	$1,011	$196	$48	1830 & 1835
5035	Overhead Distribution Transformers- Operation	$20,758	$16,198	$1,485	$143	$2,362	$458	$112	1850
5040	Underground Distribution Lines and Feeders - Operation Labour	$34,229	$26,697	$2,447	$252	$3,893	$755	$184	1840 & 1845
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$381	$297	$27	$3	$43	$8	$2	1840 & 1845
5055	Underground Distribution Transformers - Operation	$6,071	$4,738	$434	$42	$691	$134	$33	1850
5065	Meter Expense	$154,933	$95,183	$19,899	$39,851	$0	$0	$0	CWMC
5070	Customer Premises - Operation Labour	$1,955	$1,524	$140	$15	$222	$43	$11	CCA
5075	Customer Premises - Materials and Expenses	$9,406	$7,334	$672	$73	$1,069	$207	$51	CCA
5085	Miscellaneous Distribution Expense	$123,853	$93,552	$10,680	$2,687	$13,641	$2,647	$646	1815-1855
5090	Underground Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	1840 & 1845
5095	Overhead Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	1830 & 1835
5096	Other Rent	$0	$0	$0	$0	$0	$0	$0	O&M
5105	Maintenance Supervision and Engineering	$16,899	$12,764	$1,457	$367	$1,861	$361	$88	1815-1855
5120	Maintenance of Poles, Towers and Fixtures	$32,500	$25,346	$2,323	$244	$3,696	$717	$175	1830

5125	Maintenance of Overhead Conductors and Devices	$112,360	$87,624	$8,032	$843	$12,776	$2,479	$605	1835
5130	Maintenance of Overhead Services	$211,250	$145,439	$26,664	$12,821	$21,206	$4,115	$1,005	1855
5135	Overhead Distribution Lines and Feeders - Right of Way	$70,620	$55,073	$5,048	$530	$8,030	$1,558	$381	1830 & 1835
5145	Maintenance of Underground Conduit	$4,420	$3,448	$316	$32	$503	$98	$24	1840
5150	Maintenance of Underground Conductors and Devices	$17,537	$13,678	$1,254	$129	$1,994	$387	$95	1845
5155	Maintenance of Underground Services	$33,617	$23,144	$4,243	$2,040	$3,375	$655	$160	1855
5160	Maintenance of Line Transformers	$80,427	$62,760	$5,753	$553	$9,151	$1,776	$434	1850
5175	Maintenance of Meters	$72,986	$44,839	$9,374	$18,773	$0	$0	$0	1860
	Sub-total	*$1,095,962*	*$789,636*	*$107,749*	*$80,990*	*$94,720*	*$18,379*	*$4,488*	
	Billing and Collection								
5305	Supervision	$0	$0	$0	$0	$0	$0	$0	CWNB
5310	Meter Reading Expense	$244,533	$191,885	$38,558	$14,090	$0	$0	$0	CWMR
5315	Customer Billing	$348,370	$270,240	$49,544	$18,817	$306	$127	$9,336	CWNB
5320	Collecting	$114,921	$89,148	$16,344	$6,207	$101	$42	$3,080	CWNB
5325	Collecting- Cash Over and Short	$626	$485	$89	$34	$1	$0	$17	CWNB
5330	Collection Charges	$4,262	$3,306	$606	$230	$4	$2	$114	CWNB
5335	Bad Debt Expense	$91,750	$88,525	$3,225	$0	$0	$0	$0	BDHA
5340	Miscellaneous Customer Accounts Expenses	$357,265	$277,140	$50,809	$19,297	$314	$130	$9,574	CWNB
	Sub-total	*$1,161,728*	*$920,731*	*$159,176*	*$58,675*	*$725*	*$301*	*$22,121*	
	Sub Total Operating, Maintenance and Biling	*$2,257,690*	*$1,710,366*	*$266,925*	*$139,665*	*$95,445*	*$18,680*	*$26,609*	
	Amortization Expense - Customer Related	$523,900	$393,957	$42,499	$25,980	$49,511	$9,607	$2,346	
	Amortization Expense - General Plant assigned to Meters	$197,803	$144,457	$19,152	$10,261	$19,281	$3,741	$912	
	Admin and General	$1,595,687	$1,203,203	$188,362	$101,919	$70,519	$13,792	$17,892	
	Allocated PILs	$74,552	$54,419	$7,250	$3,856	$7,271	$1,411	$345	
	Allocated Debt Return	$537,414	$392,278	$52,265	$27,800	$52,417	$10,171	$2,484	
	Allocated Equity Return	$681,997	$497,815	$66,326	$35,279	$66,519	$12,907	$3,152	
	PLCC Adjustment for Line Transformer	$94,658	$83,840	$7,687	$743	$0	$2,388	$0	
	PLCC Adjustment for Primary Costs	$187,398	$165,827	$15,204	$1,648	$0	$4,719	$0	
	PLCC Adjustment for Secondary Costs	$111,820	$80,225	$6,710	$695	$0	$24,190	$0	
	Total	$4,821,363	**$3,606,646**	**$522,658**	**$259,198**	**$354,078**	**$37,498**	**$41,285**	

Below: Grouping to avoid disclosure

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

Accounts	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
Distribution Plant							
CWMC	$ 2,402,778	$ 1,476,138	$ 308,605	$ 618,035	$ -	$ -	$ -
Accumulated Amortization							
Accum. Amortization of Electric Utility Plant - Meters only	$ (1,241,730)	$ (762,852)	$ (159,484)	$ (319,394)	$ -	$ -	$ -
Meter Net Fixed Assets	$ 1,161,048	$ 713,286	$ 149,121	$ 298,641	$ -	$ -	$ -
Misc Revenue							
CWNB	$ (6,535)	$ (5,070)	$ (929)	$ (353)	$ (6)	$ (2)	$ (175)
NFA	$ (133,181)	$ (77,331)	$ (14,967)	$ (33,438)	$ (5,978)	$ (1,176)	$ (291)
LPHA	$ (71,821)	$ (34,479)	$ (11,724)	$ (24,796)	$ (513)	$ (174)	$ (136)
Sub-total	$ (211,537)	$ (116,879)	$ (27,621)	$ (58,587)	$ (6,497)	$ (1,352)	$ (602)
Operation							
CWMC	$ 154,933	$ 95,183	$ 19,899	$ 39,851	$ -	$ -	$ -
CCA	$ 11,361	$ 8,858	$ 812	$ 88	$ 1,292	$ 251	$ 61
Sub-total	$ 166,294	$ 104,040	$ 20,711	$ 39,940	$ 1,292	$ 251	$ 61
Maintenance							
1860	$ 72,986	$ 44,839	$ 9,374	$ 18,773	$ -	$ -	$ -
Billing and Collection							
CWMR	$ 244,533	$ 191,885	$ 38,558	$ 14,090	$ -	$ -	$ -
CWNB	$ 468,179	$ 363,180	$ 66,583	$ 25,288	$ 411	$ 171	$ 12,547
Sub-total	$ 712,712	$ 555,065	$ 105,141	$ 39,378	$ 411	$ 171	$ 12,547
Total Operation, Maintenance and Billing	$ 951,992	$ 703,944	$ 135,226	$ 98,090	$ 1,703	$ 422	$ 12,608
Amortization Expense - Meters	$ 88,542	$ 54,395	$ 11,372	$ 22,775	$ -	$ -	$ -
Allocated PILs	$ 6,717	$ 4,127	$ 863	$ 1,727	$ -	$ -	$ -
Allocated Debt Return	$ 48,420	$ 29,747	$ 6,222	$ 12,452	$ -	$ -	$ -
Allocated Equity Return	$ 61,447	$ 37,749	$ 7,896	$ 15,802	$ -	$ -	$ -
Total	**$ 945,581**	**$ 713,083**	**$ 133,958**	**$ 92,259**	**$ (4,794)**	**$ (931)**	**$ 12,006**

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

Accounts	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
Distribution Plant							
CWMC	$ 2,402,778	$ 1,476,138	$ 308,605	$ 618,035	$ -	$ -	$ -
Accumulated Amortization							
Accum. Amortization of Electric Utility Plant - Meters only	$ (1,241,730)	$ (762,852)	$ (159,484)	$ (319,394)	$ -	$ -	$ -
Meter Net Fixed Assets	$ 1,161,048	$ 713,286	$ 149,121	$ 298,641	$ -	$ -	$ -
Allocated General Plant Net Fixed Assets	$ 118,822	$ 73,000	$ 15,186	$ 30,636	$ -	$ -	$ -
Meter Net Fixed Assets Including General Plant	$ 1,279,870	$ 786,285	$ 164,307	$ 329,277	$ -	$ -	$ -
Misc Revenue							
CWNB	$ (6,535)	$ (5,070)	$ (929)	$ (353)	$ (6)	$ (2)	$ (175)
NFA	$ (133,181)	$ (77,331)	$ (14,967)	$ (33,438)	$ (5,978)	$ (1,176)	$ (291)
LPHA	$ (71,821)	$ (34,479)	$ (11,724)	$ (24,796)	$ (513)	$ (174)	$ (136)
Sub-total	*$ (211,537)*	*$ (116,879)*	*$ (27,621)*	*$ (58,587)*	*$ (6,497)*	*$ (1,352)*	*(602)*
Operation							
CWMC	$ 154,933	$ 95,183	$ 19,899	$ 39,851	$ -	$ -	$ -

CCA	$ 11,361	$ 8,858	$ 812	$ 88	$ 1,292	$ 251	$ 61
Sub-total	*$ 166,294*	*$ 104,040*	*$ 20,711*	*$ 39,940*	*$ 1,292*	*$ 251*	*$ 61*
Maintenance							
1860	$ 72,986	$ 44,839	$ 9,374	$ 18,773	$ -	$ -	$ -
Billing and Collection							
CWMR	$ 244,533	$ 191,885	$ 38,558	$ 14,090	$ -	$ -	$ -
CWNB	$ 468,179	$ 363,180	$ 66,583	$ 25,288	$ 411	$ 171	$ 12,547
Sub-total	*$ 712,712*	*$ 555,065*	*$ 105,141*	*$ 39,378*	*$ 411*	*$ 171*	*$ 12,547*
Total Operation, Maintenance and Billing	$ 951,992	$ 703,944	$ 135,226	$ 98,090	$ 1,703	$ 422	$ 12,608
Amortization Expense - Meters	$ 88,542	$ 54,395	$ 11,372	$ 22,775	$ -	$ -	$ -
Amortization Expense - General Plant assigned to Meters	$ 19,655	$ 12,075	$ 2,512	$ 5,068	$ -	$ -	$ -
Admin and General	$ 672,261	$ 495,208	$ 95,426	$ 71,580	$ 1,258	$ 311	$ 8,477
Allocated PILs	$ 7,404	$ 4,549	$ 951	$ 1,905	$ -	$ -	$ -
Allocated Debt Return	$ 53,375	$ 32,791	$ 6,855	$ 13,729	$ -	$ -	$ -
Allocated Equity Return	$ 67,735	$ 41,613	$ 8,700	$ 17,423	$ -	$ -	$ -
Total	**$ 1,649,427**	**$ 1,227,696**	**$ 233,422**	**$ 171,982**	**$ (3,537)**	**$ (620)**	**$ 20,483**

Scenario 3

Minimum System Customer Costs Adjusted for PLCC - High Limit Fixed Customer Charge

USoA Account #	Accounts	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
	Distribution Plant							
	CDMPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Poles, Towers and Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	PNCP	$ 6,312,064	$ 4,921,434	$ 451,134	$ 48,660	$ 717,593	$ 139,239	$ 34,004
	SNCP	$ 2,497,904	$ 1,949,213	$ 178,679	$ 17,183	$ 284,214	$ 55,148	$ 13,468
	Overhead Conductors and Devices	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	LTNCP	$ 2,841,070	$ 2,216,998	$ 203,226	$ 19,543	$ 323,260	$ 62,724	$ 15,318
	CWCS	$ 4,293,321	$ 2,955,818	$ 541,903	$ 260,564	$ 430,987	$ 83,627	$ 20,423
	CWMC	$ 2,402,778	$ 1,476,138	$ 308,605	$ 618,035	$ -	$ -	$ -
	Sub-total	*$ 18,347,137*	*$ 13,519,601*	*$ 1,683,546*	*$ 963,986*	*$ 1,756,054*	*$ 340,738*	*$ 83,212*
	Accumulated Amortization							
	Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	$ (6,657,012)	$ (4,986,544)	$ (546,657)	$ (359,275)	$ (615,855)	$ (119,498)	$ (29,183)
	Customer Related Net Fixed Assets	$ 11,690,125	$ 8,533,057	$ 1,136,889	$ 604,711	$ 1,140,199	$ 221,240	$ 54,029
	Allocated General Plant Net Fixed Assets	$ 1,195,794	$ 873,298	$ 115,779	$ 62,033	$ 116,559	$ 22,613	$ 5,512
	Customer Related NFA Including General Plant	$ 12,885,919	$ 9,406,355	$ 1,252,668	$ 666,745	$ 1,256,758	$ 243,852	$ 59,541
	Misc Revenue							
	CWNB	$ (448,800)	$ (348,147)	$ (63,827)	$ (24,241)	$ (394)	$ (164)	$ (12,027)
	NFA	$ (133,181)	$ (77,331)	$ (14,967)	$ (33,438)	$ (5,978)	$ (1,176)	$ (291)
	LPHA	$ (71,821)	$ (34,479)	$ (11,724)	$ (24,796)	$ (513)	$ (174)	$ (136)
	Sub-total	*$ (653,802)*	*$ (459,956)*	*$ (90,518)*	*$ (82,475)*	*$ (6,885)*	*$ (1,514)*	*$ (12,454)*
	Operating and Maintenance							
	1815-1855	$ 204,409	$ 154,399	$ 17,627	$ 4,435	$ 22,513	$ 4,368	$ 1,067
	1830 & 1835	$ 98,724	$ 76,990	$ 7,057	$ 740	$ 11,226	$ 2,178	$ 532
	1850	$ 107,256	$ 83,696	$ 7,672	$ 738	$ 12,204	$ 2,368	$ 578
	1840 & 1845	$ 34,610	$ 26,994	$ 2,474	$ 255	$ 3,936	$ 764	$ 187
	CWMC	$ 154,933	$ 95,183	$ 19,899	$ 39,851	$ -	$ -	$ -
	CCA	$ 11,361	$ 8,858	$ 812	$ 88	$ 1,292	$ 251	$ 61
	O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1830	$ 32,500	$ 25,346	$ 2,323	$ 244	$ 3,696	$ 717	$ 175
	1835	$ 112,360	$ 87,624	$ 8,032	$ 843	$ 12,776	$ 2,479	$ 605
	1855	$ 244,866	$ 168,583	$ 30,907	$ 14,861	$ 24,581	$ 4,770	$ 1,165
	1840	$ 4,420	$ 3,448	$ 316	$ 32	$ 503	$ 98	$ 24
	1845	$ 17,537	$ 13,678	$ 1,254	$ 129	$ 1,994	$ 387	$ 95
	1860	$ 72,986	$ 44,839	$ 9,374	$ 18,773	$ -	$ -	$ -
	Sub-total	*$ 1,095,962*	*$ 789,636*	*$ 107,749*	*$ 80,990*	*$ 94,720*	*$ 18,379*	*$ 4,488*
	Billing and Collection							
	CWNB	$ 825,444	$ 640,320	$ 117,393	$ 44,585	$ 725	$ 301	$ 22,121
	CWMR	$ 244,533	$ 191,885	$ 38,558	$ 14,090	$ -	$ -	$ -
	BDHA	$ 91,750	$ 88,525	$ 3,225	$ -	$ -	$ -	$ -
	Sub-total	*$ 1,161,728*	*$ 920,731*	*$ 159,176*	*$ 58,675*	*$ 725*	*$ 301*	*$ 22,121*
	Sub Total Operating, Maintenance and Biling	*$ 2,257,690*	*$ 1,710,366*	*$ 266,925*	*$ 139,665*	*$ 95,445*	*$ 18,680*	*$ 26,609*
	Amortization Expense - Customer Related	$ 523,900	$ 393,957	$ 42,499	$ 25,980	$ 49,511	$ 9,607	$ 2,346
	Amortization Expense - General Plant assigned to Meters	$ 197,803	$ 144,457	$ 19,152	$ 10,261	$ 19,281	$ 3,741	$ 912
	Admin and General	$ 1,595,687	$ 1,203,203	$ 188,362	$ 101,919	$ 70,519	$ 13,792	$ 17,892
	Allocated PILs	$ 74,552	$ 54,419	$ 7,250	$ 3,856	$ 7,271	$ 1,411	$ 345
	Allocated Debt Return	$ 537,414	$ 392,278	$ 52,265	$ 27,800	$ 52,417	$ 10,171	$ 2,484
	Allocated Equity Return	$ 681,997	$ 497,815	$ 66,326	$ 35,279	$ 66,519	$ 12,907	$ 3,152
	PLCC Adjustment for Line Transformer	$ 94,658	$ 83,840	$ 7,687	$ 743	$ -	$ 2,388	$ -
	PLCC Adjustment for Primary Costs	$ 187,398	$ 165,827	$ 15,204	$ 1,648	$ -	$ 4,719	$ -
	PLCC Adjustment for Secondary Costs	$ 111,820	$ 80,225	$ 6,710	$ 695	$ -	$ 24,190	$ -
	Total	**$ 4,821,363**	**$ 3,606,646**	**$ 522,658**	**$ 259,198**	**$ 354,078**	**$ 37,498**	**$ 41,285**

2006 COST ALLOCATION INFORMATION FILING

Canadian Niagara Power Inc - Fort Erie & EOP

Monday, July 14, 2008

Sheet O2.1 Line Transformer Worksheet - Second Run

Line Transformers Demand Unit Cost for PLCC
Adjustment to Customer Related Cost
Allocation by rate classification

		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Description	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**GS> 50-TOU**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Embedded Distributor**	**Back-up/Standby Power**	**Rate Class 1**	**Rate class 2**	**Rate class 3**	**Rate class 4**	**Rate class 5**	**Rate class 6**	**Rate class 7**	**Rate class 8**	**Rate class 9**
Depreciation on Acct 1850 Line Transformers	$124,571	$57,680	$16,370	$50,499	$0	$0	$0	$0	$22	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation on General Plant Assigned to Line Transformers	$45,476	$21,050	$5,945	$18,473	$0	$0	$0	$0	$8	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5035 - Overhead Distribution Transformers- Operation	$31,136	$14,417	$4,092	$12,622	$0	$0	$0	$0	$5	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5055 - Underground Distribution Transformers - Operation	$9,107	$4,217	$1,197	$3,692	$0	$0	$0	$0	$2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5160 - Maintenance of Line Transformers	$120,640	$55,860	$15,854	$48,906	$0	$0	$0	$0	$21	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Allocation of General Expenses	$63,891	$29,583	$8,396	$25,901	$0	$0	$0	$0	$11	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Admin and General Assigned to Line Transformers	$114,938	$52,404	$14,920	$47,593	$0	$0	$0	$0	$21	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PILs on Line Transformers	$17,126	$7,930	$2,251	$6,943	$0	$0	$0	$0	$3	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Debt Return on Line Transformers	$123,454	$57,163	$16,224	$50,046	$0	$0	$0	$0	$21	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Equity Return on Line Transformers	$156,667	$72,541	$20,588	$63,511	$0	$0	$0	$0	$27	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total	**$807,007**	**$372,845**	**$105,836**	**$328,186**	**$0**	**$0**	**$0**	**$0**	**$141**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Line Tranformer NCP	257,997	119,460	33,904	104,588	0	0	0	0	45	0	0	0	0	0	0	0	0	0	0	0	0
PLCC Amount	33,001	26,862	2,462	237	0	0	0	2,500	760	179	0	0	0	0	0	0	0	0	0	0	0
Adjustment to Customer Related Cost for PLCC	**$94,658**	**$83,840**	**$7,687**	**$743**	**$0**	**$0**	**$0**	**$0**	**$2,388**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Plant - Gross Assets	$5,415,496	$3,144,576	$605,633	$1,362,907	$0	$0	$0	$242,821	$47,758	$11,800	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
General Plant - Accumulated Depreciation	($2,793,148)	($1,621,876)	($312,367)	($702,946)	$0	$0	$0	($125,240)	($24,632)	($6,086)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
General Plant - Net Fixed Assets	$2,622,348	$1,522,699	$293,266	$659,961	$0	$0	$0	$117,581	$23,126	$5,714	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
General Plant - Depreciation	$433,777	$251,878	$48,511	$109,168	$0	$0	$0	$19,450	$3,825	$945	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Net Fixed Assets Excluding General Plant	**$25,623,982**	**$14,878,403**	**$2,879,715**	**$6,433,393**	**$0**	**$0**	**$0**	**$1,150,202**	**$226,259**	**$56,010**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Total Administration and General Expense	$2,387,875	$1,555,981	$287,247	$441,901	$0	$0	$0	$70,799	$14,005	$17,942	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total O&M	**$3,365,935**	**$2,211,845**	**$407,053**	**$605,561**	**$0**	**$0**	**$0**	**$95,823**	**$18,968**	**$26,684**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Line Transformer Rate Base																					
Acct 1850 - Line Transformers - Gross Assets	$4,261,605	$1,973,240	$560,034	$1,727,591	$0	$0	$0	$0	$740	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Line Transformers - Accumulated Depreciation	($1,576,167)	($729,809)	($207,130)	($638,954)	$0	$0	$0	$0	($274)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Line Transformers - Net Fixed Assets	$2,685,438	$1,243,432	$352,904	$1,088,636	$0	$0	$0	$0	$466	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
General Plant Assigned to Line Transformers - NFA	$274,920	$127,256	$35,939	$111,676	$0	$0	$0	$0	$48	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Line Transformer Net Fixed Assets Including General Plant	$2,960,357	$1,370,688	$388,843	$1,200,312	$0	$0	$0	$0	$514	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
General Expenses																					
Acct 5005 - Operation Supervision and Engineering	$8,429	$3,794	$1,075	$3,558	$0	$0	$0	$0	$2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5010 - Load Dispatching	$87,057	$39,184	$11,099	$36,754	$0	$0	$0	$4	$16	$1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5085 - Miscellaneous Distribution Expense	$185,780	$83,618	$23,685	$78,433	$0	$0	$0	$8	$33	$2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5105 - Maintenance Supervision and Engineering	$25,348	$11,409	$3,232	$10,702	$0	$0	$0	$1	$5	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total	$306,613	$138,004	$39,090	$129,448	$0	$0	$0	$13	$55	$3	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1850 - Line Transformers - Gross Assets	$4,261,605	$1,973,240	$560,034	$1,727,591	$0	$0	$0	$0	$740	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1815 - 1855	$20,451,390	$9,205,021	$2,607,346	$8,634,270	$0	$0	$0	$891	$3,685	$176	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

2006 COST ALLOCATION INFORMATION FILING
Canadian Niagara Power Inc - Fort Erie & EOP

Monday, July 14, 2008
Sheet O2.2 Primary Cost PLCC Adjustment Worksheet - Second Run

Primary Conductors and Poles Cost Pool Demand Unit Cost for PLCC Adjustment to Customer Related Cost

Allocation by Rate Classification

		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Description	Total	Residential	GS <50	GS>50-Regular	GS> 50-TOU	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load	Embedded Distributor	Back-up/Standby Power	Rate Class 1	Rate class 2	Rate class 3	Rate class 4	Rate class 5	Rate class 6	Rate class 7	Rate class 8	Rate class 9
Depreciation on Acct 1830-4 Primary Poles, Towers & Fixtures	$176,409	$77,808	$22,083	$76,488	$0	$0	$0	$0	$29	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation on Acct 1835-4 Primary Overhead Conductors	$142,644	$62,916	$17,856	$61,848	$0	$0	$0	$0	$24	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation on Acct 1840-4 Primary Underground Conduit	$3,508	$1,547	$439	$1,521	$0	$0	$0	$0	$1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation on Acct 1845-4 Primary Underground Conductors	$57,379	$25,308	$7,183	$24,879	$0	$0	$0	$0	$9	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation on General Plant Assigned to Primary C&P	$79,882	$35,219	$9,946	$34,703	$0	$0	$0	$0	$13	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Primary C&P Operations and Maintenance	$321,790	$141,927	$40,284	$139,526	$0	$0	$0	$0	$53	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Allocation of General Expenses	$141,949	$62,609	$17,769	$61,547	$0	$0	$0	$0	$23	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Admin and General Assigned to Primary C&P	$230,126	$99,842	$28,427	$101,818	$0	$0	$0	$0	$39	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PILs on Primary C&P	$30,080	$13,267	$3,765	$13,042	$0	$0	$0	$0	$5	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Debt Return on Primary C&P	$216,834	$95,639	$27,144	$94,016	$0	$0	$0	$0	$36	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Equity Return on Primary C&P	$275,171	$121,369	$34,446	$119,310	$0	$0	$0	$0	$45	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total	**$1,675,771**	**$737,451**	**$209,344**	**$728,698**	**$0**	**$0**	**$0**	**$0**	**$278**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Primary NCP	270,842	119,460	33,904	117,433	0	0	0	0	45	0	0	0	0	0	0	0	0	0	0	0	0
PLCC Amount	33,030	26,862	2,462	266	0	0	0	2,500	760	179	0	0	0	0	0	0	0	0	0	0	0
Adjustment to Customer Related Cost for PLCC	**$187,398**	**$165,827**	**$15,204**	**$1,648**	**$0**	**$0**	**$0**	**$0**	**$4,719**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Plant - Gross Assets	$5,415,496	$3,144,576	$605,633	$1,362,907	$0	$0	$0	$242,821	$47,758	$11,800	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
General Plant - Accumulated Depreciation	($2,793,148)	($1,621,876)	($312,367)	($702,946)	$0	$0	$0	($125,240)	($24,632)	($6,086)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
General Plant - Net Fixed Assets	$2,622,348	$1,522,699	$293,266	$659,961	$0	$0	$0	$117,581	$23,126	$5,714	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
General Plant - Depreciation	$433,777	$251,878	$48,511	$109,168	$0	$0	$0	$19,450	$3,825	$945	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Net Fixed Assets Excluding General Plant	**$25,623,982**	**$14,878,403**	**$2,879,715**	**$6,433,393**	**$0**	**$0**	**$0**	**$1,150,202**	**$226,259**	**$56,010**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Total Administration and General Expense	**$2,387,875**	**$1,555,981**	**$287,247**	**$441,901**	**$0**	**$0**	**$0**	**$70,799**	**$14,005**	**$17,942**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Total O&M	**$3,365,935**	**$2,211,845**	**$407,053**	**$605,561**	**$0**	**$0**	**$0**	**$95,823**	**$18,968**	**$26,684**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Primary Conductors and Poles Gross Assets																					
Acct 1830-4 Primary Poles, Towers & Fixtures	$4,337,608	$1,913,180	$542,988	$1,880,722	$0	$0	$0	$0	$717	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1835-4 Primary Overhead Conductors	$3,629,576	$1,600,890	$454,356	$1,573,730	$0	$0	$0	$0	$600	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1840-4 Primary Underground Conduit	$145,088	$63,994	$18,162	$62,908	$0	$0	$0	$0	$24	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1845-4 Primary Underground Conductors	$1,355,824	$598,010	$169,724	$587,865	$0	$0	$0	$0	$224	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal	*$9,468,096*	*$4,176,075*	*$1,185,230*	*$4,105,226*	*$0*	*$0*	*$0*	*$0*	*$1,565*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*
Primary Conductors and Poles Accumulated Depreciation																					
Acct 1830-4 Primary Poles, Towers & Fixtures	($1,943,014)	($857,002)	($243,229)	($842,462)	$0	$0	$0	$0	($321)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1835-4 Primary Overhead Conductors	($2,235,079)	($985,822)	($279,790)	($969,097)	$0	$0	$0	$0	($369)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1840-4 Primary Underground Conduit	($42,181)	($18,605)	($5,280)	($18,289)	$0	$0	$0	$0	($7)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1845-4 Primary Underground Conductors	($531,119)	($234,260)	($66,486)	($230,285)	$0	$0	$0	$0	($88)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal	***($4,751,392)***	***($2,095,687)***	***($594,786)***	***($2,060,133)***	***$0***	***$0***	***$0***	***$0***	***($785)***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***
Primary Conductor & Pools - Net Fixed Assets	$4,716,703	$2,080,387	$590,444	$2,045,093	$0	$0	$0	$0	$780	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
General Plant Assigned to Primary C&P - NFA	$482,916	$212,913	$60,130	$209,793	$0	$0	$0	$0	$80	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Primary C&P Net Fixed Assets Including General Plant	$5,199,619	$2,293,300	$650,574	$2,254,886	$0	$0	$0	$0	$859	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1830-3 Bulk Poles, Towers & Fixtures	$26,530	$12,584	$3,047	$10,762	$0	$0	$0	$90	$29	$18	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1835-3 Bulk Overhead Conductors	$5,658	$2,684	$650	$2,295	$0	$0	$0	$19	$6	$4	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1840-3 Bulk Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1845-3 Bulk Underground Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal	***$32,188***	***$15,267***	***$3,697***	***$13,058***	***$0***	***$0***	***$0***	***$110***	***$35***	***$22***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***
Acct 1830-5 Secondary Poles, Towers & Fixtures	$1,467,384	$679,439	$192,835	$594,855	$0	$0	$0	$0	$255	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1835-5 Secondary Overhead Conductors	$1,228,881	$569,006	$161,492	$498,170	$0	$0	$0	$0	$213	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1840-5 Secondary Underground Conduit	$146,725	$67,938	$19,282	$59,480	$0	$0	$0	$0	$25	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1845-5 Secondary Underground Conductors	$903,866	$418,515	$118,781	$366,414	$0	$0	$0	$0	$157	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal	***$3,746,856***	***$1,734,898***	***$492,389***	***$1,518,919***	***$0***	***$0***	***$0***	***$0***	***$650***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***
Operations and Maintenance																					
Acct 5020 Overhead Distribution Lines & Feeders - Labour	$28,815	$12,872	$3,652	$12,287	$0	$0	$0	$0	$5	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5025 Overhead Distribution Lines & Feeders - Other	$13,341	$5,959	$1,691	$5,688	$0	$0	$0	$0	$2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5040 Underground Distribution Lines & Feeders - Labour	$51,343	$23,110	$6,559	$21,666	$0	$0	$0	$0	$9	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5045 Underground Distribution Lines & Feeders - Other	$571	$257	$73	$241	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5090 Underground Distribution Lines & Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5095 Overhead Distribution Lines & Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5120 Maintenance of Poles, Towers & Fixtures	$48,751	$21,779	$6,177	$20,785	$0	$0	$0	$1	$8	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5125 Maintenance of Overhead Conductors & Devices	$168,539	$75,279	$21,361	$71,870	$0	$0	$0	$1	$28	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5135 Overhead Distribution Lines & Feeders - Right of Way	$105,929	$47,319	$13,424	$45,167	$0	$0	$0	$1	$18	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5145 Maintenance of Underground Conduit	$6,630	$2,998	$851	$2,781	$0	$0	$0	$0	$1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5150 Maintenance of Underground Conductors & Devices	$26,306	$11,834	$3,359	$11,109	$0	$0	$0	$0	$4	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total	**$450,227**	**$201,407**	**$57,145**	**$191,594**	**$0**	**$0**	**$0**	**$3**	**$76**	**$1**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Expenses																					
Acct 5005 - Operation Supervision and Engineering	$8,429	$3,794	$1,075	$3,558	$0	$0	$0	$0	$2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5010 - Load Dispatching	$87,057	$39,184	$11,099	$36,754	$0	$0	$0	$4	$16	$1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5085 - Miscellaneous Distribution Expense	$185,780	$83,618	$23,685	$78,433	$0	$0	$0	$8	$33	$2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5105 - Maintenance Supervision and Engineering	$25,348	$11,409	$3,232	$10,702	$0	$0	$0	$1	$5	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total	**$306,613**	**$138,004**	**$39,090**	**$129,448**	**$0**	**$0**	**$0**	**$13**	**$55**	**$3**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Primary Conductors and Poles Gross Assets	$9,468,096	$4,176,075	$1,185,230	$4,105,226	$0	$0	$0	$0	$1,565	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1815 - 1855	$20,451,390	$9,205,021	$2,607,346	$8,634,270	$0	$0	$0	$891	$3,685	$176	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

2006 COST ALLOCATION INFORMATION FILING
Canadian Niagara Power Inc - Fort Erie & EOP

Monday, July 14, 2008

Sheet O2.3 Secondary Cost PLCC Adjustment Worksheet - Second Run

Secondary Conductors and Poles Cost Pool Demand Unit Cost for PLCC Adjustment to Customer Related Cost

Allocation by Rate Classification

Description		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
	Total	Residential	GS <50	GS>50-Regular	GS> 50-TOU	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load	Embedded Distributor	Back-up/Standby Power	Rate Class 1	Rate class 2	Rate class 3	Rate class 4	Rate class 5	Rate class 6	Rate class 7	Rate class 8	Rate class 9
Depreciation on Acct 1830-5 Secondary Poles, Towers & Fixtures	$59,654	$27,621	$7,839	$24,183	$0	$0	$0	$0	$10	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation on Acct 1835-5 Secondary Overhead Conductors	$80,471	$47,474	$8,647	$19,794	$0	$0	$0	$3,662	$719	$174	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation on Acct 1840-5 Secondary Underground Conduit	$3,897	$2,299	$419	$959	$0	$0	$0	$177	$35	$8	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation on Acct 1845-5 Secondary Underground Conductors	$63,752	$37,611	$6,851	$15,682	$0	$0	$0	$2,902	$570	$137	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation on General Plant Assigned to Secondary C&P	$33,047	$15,297	$4,320	$13,424	$0	$0	$0	$0	$6	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Secondary C&P Operations and Maintenance	$127,343	$58,962	$16,735	$51,624	$0	$0	$0	$0	$22	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Allocation of General Expenses	$56,174	$26,010	$7,382	$22,772	$0	$0	$0	$0	$10	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Admin and General Assigned to Primary C&P	$90,976	$41,478	$11,810	$37,672	$0	$0	$0	$0	$16	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PILs on Secondary C&P	$12,445	$5,763	$1,635	$5,045	$0	$0	$0	$0	$2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Debt Return on Secondary C&P	$89,713	$41,540	$11,790	$36,368	$0	$0	$0	$0	$16	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Equity Return on Secondary C&P	$113,849	$52,715	$14,961	$46,153	$0	$0	$0	$0	$20	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total	**$731,323**	**$356,770**	**$92,390**	**$273,677**	**$0**	**$0**	**$0**	**$6,741**	**$1,425**	**$319**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Secondary NCP	257,997	119,460	33,904	104,588	0	0	0	0	45	0	0	0	0	0	0	0	0	0	0	0	0
PLCC Amount	33,030	26,862	2,462	266	0	0	0	2,500	760	179	0	0	0	0	0	0	0	0	0	0	0
Adjustment to Customer Related Cost for PLCC	**$111,820**	**$80,225**	**$6,710**	**$695**	**$0**	**$0**	**$0**	**$0**	**$24,190**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Plant - Gross Assets	$5,415,496	$3,144,576	$605,633	$1,362,907	$0	$0	$0	$242,821	$47,758	$11,800	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
General Plant - Accumulated Depreciation	($2,793,148)	($1,621,876)	($312,367)	($702,946)	$0	$0	$0	($125,240)	($24,632)	($6,086)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
General Plant - Net Fixed Assets	$2,622,348	$1,522,699	$293,266	$659,961	$0	$0	$0	$117,581	$23,126	$5,714	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
General Plant - Depreciation	$433,777	$251,878	$48,511	$109,168	$0	$0	$0	$19,450	$3,825	$945	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Net Fixed Assets Excluding General Plant	$25,623,982	$14,878,403	$2,879,715	$6,433,393	$0	$0	$0	$1,150,202	$226,259	$56,010	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Administration and General Expense	$2,387,875	$1,555,981	$287,247	$441,901	$0	$0	$0	$70,799	$14,005	$17,942	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total O&M	$3,365,935	$2,211,845	$407,053	$605,561	$0	$0	$0	$95,823	$18,968	$26,684	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Secondary Conductors and Poles Gross Plant																					
Acct 1830-5 Secondary Poles, Towers & Fixtures	$1,467,384	$679,439	$192,835	$594,855	$0	$0	$0	$0	$255	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1835-5 Secondary Overhead Conductors	$1,228,881	$569,006	$161,492	$498,170	$0	$0	$0	$0	$213	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1840-5 Secondary Underground Conduit	$146,725	$67,938	$19,282	$59,480	$0	$0	$0	$0	$25	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1845-5 Secondary Underground Conductors	$903,866	$418,515	$118,781	$366,414	$0	$0	$0	$0	$157	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal	*$3,746,856*	*$1,734,898*	*$492,389*	*$1,518,919*	*$0*	*$0*	*$0*	*$0*	*$650*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*
Secondary Conductors and Poles Accumulated Depreciation																					
Acct 1830-5 Secondary Poles, Towers & Fixtures	($656,740)	($304,089)	($86,305)	($266,233)	$0	$0	$0	$0	($114)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1835-5 Secondary Overhead Conductors	($756,444)	($350,254)	($99,407)	($306,651)	$0	$0	$0	$0	($131)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1840-5 Secondary Underground Conduit	($28,120)	($13,020)	($3,695)	($11,400)	$0	$0	$0	$0	($5)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1845-5 Secondary Underground Conductors	($354,060)	($163,940)	($46,528)	($143,531)	$0	$0	$0	$0	($61)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal	*($1,795,364)*	*($831,303)*	*($235,936)*	*($727,814)*	*$0*	*$0*	*$0*	*$0*	*($312)*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*
Secondary Conductor & Pools - Net Fixed Assets	$1,951,492	$903,594	$256,453	$791,105	$0	$0	$0	$0	$339	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
General Plant Assigned to Secondary C&P - NFA	$199,782	$92,476	$26,117	$81,155	$0	$0	$0	$0	$35	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Secondary C&P Net Fixed Assets Including General Plant	$2,151,274	$996,071	$282,570	$872,260	$0	$0	$0	$0	$373	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1830-3 Bulk Poles, Towers & Fixtures	$26,530	$12,584	$3,047	$10,762	$0	$0	$0	$90	$29	$18	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1835-3 Bulk Overhead Conductors	$5,658	$2,684	$650	$2,295	$0	$0	$0	$19	$6	$4	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1840-3 Bulk Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1845-3 Bulk Underground Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal	*$32,188*	*$15,267*	*$3,697*	*$13,058*	*$0*	*$0*	*$0*	*$110*	*$35*	*$22*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*
Acct 1830-4 Primary Poles, Towers & Fixtures	$4,337,608	$1,913,180	$542,988	$1,880,722	$0	$0	$0	$0	$717	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1835-4 Primary Overhead Conductors	$3,629,576	$1,600,890	$454,356	$1,573,730	$0	$0	$0	$0	$600	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1840-4 Primary Underground Conduit	$145,088	$63,994	$18,162	$62,908	$0	$0	$0	$0	$24	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1845-4 Primary Underground Conductors	$1,355,824	$598,010	$169,724	$587,865	$0	$0	$0	$0	$224	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal	*$9,468,096*	*$4,176,075*	*$1,185,230*	*$4,105,226*	*$0*	*$0*	*$0*	*$0*	*$1,565*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*
Operations and Maintenance																					
Acct 5020 Overhead Distribution Lines & Feeders - Labour	$28,815	$12,872	$3,652	$12,287	$0	$0	$0	$0	$5	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5025 Overhead Distribution Lines & Feeders - Other	$13,341	$5,959	$1,691	$5,688	$0	$0	$0	$0	$2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5040 Underground Distribution Lines & Feeders - Labour	$51,343	$23,110	$6,559	$21,666	$0	$0	$0	$0	$9	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5045 Underground Distribution Lines & Feeders - Other	$571	$257	$73	$241	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5090 Underground Distribution Lines & Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5095 Overhead Distribution Lines & Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5120 Maintenance of Poles, Towers & Fixtures	$48,751	$21,779	$6,177	$20,785	$0	$0	$0	$1	$8	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5125 Maintenance of Overhead Conductors & Devices	$168,539	$75,279	$21,361	$71,870	$0	$0	$0	$1	$28	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5135 Overhead Distribution Lines & Feeders - Right of Way	$105,929	$47,319	$13,424	$45,167	$0	$0	$0	$1	$18	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5145 Maintenance of Underground Conduit	$6,630	$2,998	$851	$2,781	$0	$0	$0	$0	$1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5150 Maintenance of Underground Conductors & Devices	$26,306	$11,834	$3,359	$11,109	$0	$0	$0	$0	$4	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total	**$450,227**	**$201,407**	**$57,145**	**$191,594**	**$0**	**$0**	**$0**	**$3**	**$76**	**$1**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Expenses																					
Acct 5005 - Operation Supervision and Engineering	$8,429	$3,794	$1,075	$3,558	$0	$0	$0	$0	$2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5010 - Load Dispatching	$87,057	$39,184	$11,099	$36,754	$0	$0	$0	$4	$16	$1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5085 - Miscellaneous Distribution Expense	$185,780	$83,618	$23,685	$78,433	$0	$0	$0	$8	$33	$2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5105 - Maintenance Supervision and Engineering	$25,348	$11,409	$3,232	$10,702	$0	$0	$0	$1	$5	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total	**$306,613**	**$138,004**	**$39,090**	**$129,448**	**$0**	**$0**	**$0**	**$13**	**$55**	**$3**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Secondary Conductors and Poles Gross Assets	$3,746,856	$1,734,898	$492,389	$1,518,919	$0	$0	$0	$0	$650	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1815 - 1855	$20,451,390	$9,205,021	$2,607,346	$8,634,270	$0	$0	$0	$891	$3,685	$176	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

2006 COST ALLOCATION INFORMATION FILING

Canadian Niagara Power Inc - Fort Erie & EOP

Monday, July 14, 2008

Ontario

Sheet O3.1 Line Transformers Unit Cost Worksheet - Second Run

ALLOCATION BY RATE CLASSIFICATION

		1	2	3	7	8	9
Description	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
Depreciation on Acct 1850 Line Transformers	$207,619	$122,485	$22,311	$51,071	$9,449	$1,855	$448
Depreciation on General Plant Assigned to Line Transformers	$75,769	$44,701	$8,102	$18,682	$3,445	$676	$163
Acct 5035 - Overhead Distribution Transformers- Operation	$51,894	$30,615	$5,577	$12,765	$2,362	$464	$112
Acct 5055 - Underground Distribution Transformers - Operation	$15,178	$8,954	$1,631	$3,734	$691	$136	$33
Acct 5160 - Maintenance of Line Transformers	$201,067	$118,620	$21,607	$49,459	$9,151	$1,797	$434
Allocation of General Expenses	$99,737	$57,662	$10,871	$26,047	$4,145	$815	$196
Admin and General Assigned to Line Transformers	$190,922	$111,282	$20,334	$48,132	$9,017	$1,769	$389
PILs on Line Transformers	$28,543	$16,839	$3,067	$7,021	$1,299	$255	$62
Debt Return on Line Transformers	$205,756	$121,386	$22,111	$50,612	$9,364	$1,838	$444
Equity Return on Line Transformers	$261,112	$154,044	$28,059	$64,229	$11,884	$2,333	$563
Less: Transformer Ownership Allowance Credit	($153,529)	($85,703)	($17,418)	($43,884)	($5,241)	($1,036)	($248)
Total	**$1,184,068**	**$700,886**	**$126,252**	**$287,868**	**$55,565**	**$10,902**	**$2,594**
Billed kW without Line Transformer Allowance		0	0	204,127	6,889	2,526	0
Billed kWh without Line Transformer Allowance		141,540,950	56,958,341	188,076,527	2,471,714	880,875	398,162
Line Transformation Unit Cost ($/kW)		**$0.0000**	**$0.0000**	**$1.4102**	**$8.0658**	**$4.3160**	**$0.0000**
Line Transformation Unit Cost ($/kWh)		**$0.0050**	**$0.0022**	**$0.0015**	**$0.0225**	**$0.0124**	**$0.0065**
General Plant - Gross Assets	$5,415,496	$3,144,576	$605,633	$1,362,907	$242,821	$47,758	$11,800
General Plant - Accumulated Depreciation	($2,793,148)	($1,621,876)	($312,367)	($702,946)	($125,240)	($24,632)	($6,086)
General Plant - Net Fixed Assets	$2,622,348	$1,522,699	$293,266	$659,961	$117,581	$23,126	$5,714
General Plant - Depreciation	$433,777	$251,878	$48,511	$109,168	$19,450	$3,825	$945
Total Net Fixed Assets Excluding General Plant	$25,623,982	$14,878,403	$2,879,715	$6,433,393	$1,150,202	$226,259	$56,010
Total Administration and General Expense	$2,387,875	$1,555,981	$287,247	$441,901	$70,799	$14,005	$17,942
Total O&M	$3,365,935	$2,211,845	$407,053	$605,561	$95,823	$18,968	$26,684
Line Transformer Rate Base							
Acct 1850 - Line Transformers - Gross Assets	$7,102,674	$4,190,239	$763,260	$1,747,134	$323,260	$63,464	$15,318
Line Transformers - Accumulated Depreciation	($2,626,945)	($1,549,772)	($282,294)	($646,183)	($119,559)	($23,472)	($5,665)
Line Transformers - Net Fixed Assets	$4,475,729	$2,640,467	$480,966	$1,100,951	$203,701	$39,991	$9,653
General Plant Assigned to Line Transformers - NFA	$458,050	$270,233	$48,981	$112,940	$20,824	$4,088	$985
Line Transformer Net Fixed Assets Including General Plant	$4,933,779	$2,910,700	$529,947	$1,213,891	$224,525	$44,079	$10,637
General Expenses							
Acct 5005 - Operation Supervision and Engineering	$14,048	$8,038	$1,559	$3,680	$619	$122	$29
Acct 5010 - Load Dispatching	$145,095	$83,022	$16,104	$38,013	$6,396	$1,256	$304
Acct 5085 - Miscellaneous Distribution Expense	$309,633	$177,170	$34,365	$81,121	$13,649	$2,680	$648
Acct 5105 - Maintenance Supervision and Engineering	$42,247	$24,173	$4,689	$11,068	$1,862	$366	$88
Total	**$511,022**	**$292,403**	**$56,717**	**$133,883**	**$22,526**	**$4,424**	**$1,069**
Acct 1850 - Line Transformers - Gross Assets	$7,102,674	$4,190,239	$763,260	$1,747,134	$323,260	$63,464	$15,318
Acct 1815 - 1855	$36,395,749	$21,248,484	$3,982,287	$8,980,221	$1,756,945	$344,423	$83,388

2006 COST ALLOCATION INFORMATION FILING

Canadian Niagara Power Inc - Fort Erie & EOP

Ontario

Monday, July 14, 2008

Sheet O3.2 Substation Transformers Unit Cost Worksheet - Second Run

ALLOCATION BY RATE CLASSIFICATION

Description	Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
Depreciation on Acct 1820-2 Distribution Station Equipment	$82,763	$36,504	$10,360	$35,885	$0	$14	$0
Depreciation on Acct 1825-2 Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0
Depreciation on Acct 1805-2 Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0
Depreciation on Acct 1806-2 Land Rights Station <50 kV	$2,568	$1,218	$295	$1,042	$9	$3	$2
Depreciation on Acct 1808-2 Buildings and Fixtures < 50 KV	($20,442)	($9,696)	($2,348)	($8,293)	($70)	($22)	($14)
Depreciation on Acct 1810-2 Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0
Depreciation on General Plant Assigned to Substation Transformers	$32,645	$16,082	$3,543	$12,761	$173	$52	$34
Acct 5012 - Station Buildings and Fixtures Expense	$94,038	$44,604	$10,801	$38,148	$320	$101	$63
Acct 5016 - Distributon Station Equipment - Labour	$51,573	$22,881	$6,414	$22,249	$14	$12	$3
Acct 5017 - Distributon Station Equipment - Other	$3,978	$1,765	$495	$1,716	$1	$1	$0
Acct 5114 - Maintenance of Distribution Station Equipment	$35,608	$15,798	$4,429	$15,362	$9	$8	$2
Allocation of General Expenses	$3,278	$1,499	$376	$1,389	$10	$3	$2
Admin and General Assigned to SubstationTransformers	$65,188	$28,452	$8,001	$28,698	$18	$16	$3
PILs on SubstationTransformers	$12,293	$6,058	$1,341	$4,796	$65	$19	$13
Debt Return on Substation Transformers	$88,616	$43,671	$9,670	$34,572	$469	$140	$93
Equity Return on Substation Transformers	$112,456	$55,420	$12,271	$43,873	$596	$178	$118
Total	**$564,562**	**$264,256**	**$65,649**	**$232,198**	**$1,614**	**$526**	**$319**
Billed kW without Substation Transformer Allowance		0	0	460,009	6,889	2,526	0
Billed kWh without Substation Transformer Allowance		141,540,950	56,958,341	188,076,527	2,471,714	880,875	398,162
Substation Transformation Unit Cost ($/kW)		**$0.0000**	**$0.0000**	**$0.5048**	**$0.2343**	**$0.2081**	**$0.0000**
Substation Transformation Unit Cost ($/kWh)		**$0.0019**	**$0.0012**	**$0.0012**	**$0.0007**	**$0.0006**	**$0.0008**
General Plant - Gross Assets	$5,415,496	$3,144,576	$605,633	$1,362,907	$242,821	$47,758	$11,800
General Plant - Accumulated Depreciation	($2,793,148)	($1,621,876)	($312,367)	($702,946)	($125,240)	($24,632)	($6,086)
General Plant - Net Fixed Assets	$2,622,348	$1,522,699	$293,266	$659,961	$117,581	$23,126	$5,714
General Plant - Depreciation	$433,777	$251,878	$48,511	$109,168	$19,450	$3,825	$945
Total Net Fixed Assets Excluding General Plant	$25,623,982	$14,878,403	$2,879,715	$6,433,393	$1,150,202	$226,259	$56,010
Total Administration and General Expense	$2,387,875	$1,555,981	$287,247	$441,901	$70,799	$14,005	$17,942
Total O&M	$3,365,935	$2,211,845	$407,053	$605,561	$95,823	$18,968	$26,684
Substation Transformer Rate Base Gross Plant							
Acct 1820-2 Distribution Station Equipment	$229,590	$108,899	$26,371	$93,137	$781	$247	$155
Acct 1825-2 Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0
Acct 1805-2 Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0
Acct 1806-2 Land Rights Station <50 kV	$104,138	$49,395	$11,962	$42,245	$354	$112	$70
Acct 1808-2 Buildings and Fixtures < 50 KV	$2,845,621	$1,349,734	$326,853	$1,154,370	$9,683	$3,063	$1,917
Acct 1810-2 Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0
Subtotal	***$3,179,350***	***$1,508,028***	***$365,186***	***$1,289,752***	***$10,819***	***$3,422***	***$2,142***
Substation Transformers - Accumulated Depreciation							
Acct 1820-2 Distribution Station Equipment	($1,072,303)	($472,959)	($134,232)	($464,935)	$0	($177)	$0
Acct 1825-2 Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0
Acct 1805-2 Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0
Acct 1806-2 Land Rights Station <50 kV	($52,687)	($24,990)	($6,052)	($21,373)	($179)	($57)	($35)
Acct 1808-2 Buildings and Fixtures < 50 KV	($126,744)	($60,117)	($14,558)	($51,416)	($431)	($136)	($85)
Acct 1810-2 Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0
Subtotal	***($1,251,734)***	***($558,066)***	***($154,842)***	***($537,724)***	***($611)***	***($370)***	***($121)***
Substation Transformers - Net Fixed Assets	$1,927,616	$949,962	$210,344	$752,029	$10,208	$3,052	$2,021
General Plant Assigned to SubstationTransformers - NFA	$197,351	$97,222	$21,421	$77,146	$1,044	$312	$206
Substation Transformer NFA Including General Plant	$2,124,966	$1,047,184	$231,765	$829,174	$11,252	$3,364	$2,227
General Expenses							
Acct 5005 - Operation Supervision and Engineering	$14,048	$8,038	$1,559	$3,680	$619	$122	$29
Acct 5010 - Load Dispatching	$145,095	$83,022	$16,104	$38,013	$6,396	$1,256	$304
Acct 5085 - Miscellaneous Distribution Expense	$309,633	$177,170	$34,365	$81,121	$13,649	$2,680	$648
Acct 5105 - Maintenance Supervision and Engineering	$42,247	$24,173	$4,689	$11,068	$1,862	$366	$88
Total	$511,022	$292,403	$56,717	$133,883	$22,526	$4,424	$1,069
Acct 1820-2 Distribution Station Equipment	$229,590	$108,899	$26,371	$93,137	$781	$247	$155
Acct 1825-2 Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0
Total	$229,590	$108,899	$26,371	$93,137	$781	$247	$155
Acct 1815 - 1855	$36,395,749	$21,248,484	$3,982,287	$8,980,221	$1,756,945	$344,423	$83,388

2006 COST ALLOCATION INFORMATION FILING
Canadian Niagara Power Inc - Fort Erie & EOP

Monday, July 14, 2008
Sheet O3.3 Primary Conductors and Poles Cost Pool Worksheet - Second Run

ALLOCATION BY RATE CLASSIFICATION

		1	2	3	7	8	9
Description	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
Depreciation on Acct 1830-4 Primary Poles, Towers & Fixtures	$294,015	$169,504	$30,489	$77,395	$13,370	$2,623	$634
Depreciation on Acct 1835-4 Primary Overhead Conductors	$237,740	$137,061	$24,653	$62,581	$10,811	$2,121	$512
Depreciation on Acct 1840-4 Primary Underground Conduit	$5,846	$3,370	$606	$1,539	$266	$52	$13
Depreciation on Acct 1845-4 Primary Underground Conductors	$95,631	$55,133	$9,917	$25,173	$4,349	$853	$206
Depreciation on General Plant Assigned to Primary C&P	$133,088	$76,724	$13,732	$35,114	$6,045	$1,186	$286
Primary C&P Operations and Maintenance	$536,835	$309,594	$55,654	$141,184	$24,447	$4,797	$1,158
Allocation of General Expenses	$221,871	$125,192	$23,306	$61,929	$9,200	$1,808	$436
Admin and General Assigned to Primary C&P	$382,477	$217,792	$39,273	$103,027	$18,063	$3,542	$779
PILs on Primary C&P	$50,134	$28,903	$5,199	$13,197	$2,280	$447	$108
Debt Return on Primary C&P	$361,391	$208,347	$37,475	$95,131	$16,434	$3,225	$779
Equity Return on Primary C&P	$458,618	$264,400	$47,558	$120,724	$20,855	$4,092	$988
Total	**$2,777,644**	**$1,596,021**	**$287,861**	**$736,995**	**$126,121**	**$24,747**	**$5,899**
General Plant - Gross Assets	$5,415,496	$3,144,576	$605,633	$1,362,907	$242,821	$47,758	$11,800
General Plant - Accumulated Depreciation	($2,793,148)	($1,621,876)	($312,367)	($702,946)	($125,240)	($24,632)	($6,086)
General Plant - Net Fixed Assets	$2,622,348	$1,522,699	$293,266	$659,961	$117,581	$23,126	$5,714
General Plant - Depreciation	$433,777	$251,878	$48,511	$109,168	$19,450	$3,825	$945
Total Net Fixed Assets Excluding General Plant	$25,623,982	$14,878,403	$2,879,715	$6,433,393	$1,150,202	$226,259	$56,010
Total Administration and General Expense	$2,387,875	$1,555,981	$287,247	$441,901	$70,799	$14,005	$17,942
Total O&M	$3,365,935	$2,211,845	$407,053	$605,561	$95,823	$18,968	$26,684
Primary Conductors and Poles Gross Assets							
Acct 1830-4 Primary Poles, Towers & Fixtures	$7,229,346	$4,167,831	$749,666	$1,903,015	$328,750	$64,506	$15,578
Acct 1835-4 Primary Overhead Conductors	$6,049,294	$3,487,513	$627,297	$1,592,384	$275,088	$53,977	$13,035
Acct 1840-4 Primary Underground Conduit	$241,813	$139,409	$25,075	$63,654	$10,996	$2,158	$521
Acct 1845-4 Primary Underground Conductors	$2,259,706	$1,302,756	$234,326	$594,833	$102,759	$20,163	$4,869
Subtotal	**$15,780,159**	**$9,097,509**	**$1,636,364**	**$4,153,886**	**$717,593**	**$140,804**	**$34,004**
Primary Conductors and Poles Accumulated Depreciation							
Acct 1830-4 Primary Poles, Towers & Fixtures	($3,238,357)	($1,866,963)	($335,810)	($852,448)	($147,262)	($28,895)	($6,978)
Acct 1835-4 Primary Overhead Conductors	($3,725,131)	($2,147,596)	($386,287)	($980,584)	($169,398)	($33,239)	($8,027)
Acct 1840-4 Primary Underground Conduit	($70,301)	($40,530)	($7,290)	($18,506)	($3,197)	($627)	($151)
Acct 1845-4 Primary Underground Conductors	($885,198)	($510,330)	($91,793)	($233,015)	($40,254)	($7,898)	($1,907)
Subtotal	**($7,918,987)**	**($4,565,420)**	**($821,180)**	**($2,084,552)**	**($360,111)**	**($70,660)**	**($17,064)**
Primary Conductor & Pools - Net Fixed Assets	$7,861,172	$4,532,089	$815,184	$2,069,334	$357,482	$70,144	$16,940
General Plant Assigned to Primary C&P - NFA	$804,566	$463,827	$83,017	$212,280	$36,544	$7,169	$1,728
Primary C&P Net Fixed Assets Including General Plant	$8,665,738	$4,995,916	$898,202	$2,281,613	$394,026	$77,313	$18,668
Acct 1830-3 Bulk Poles, Towers & Fixtures	$26,530	$12,584	$3,047	$10,762	$90	$29	$18
Acct 1835-3 Bulk Overhead Conductors	$5,658	$2,684	$650	$2,295	$19	$6	$4
Acct 1840-3 Bulk Underground Conduit	$0	$0	$0	$0	$0	$0	$0
Acct 1845-3 Bulk Underground Conductors	$0	$0	$0	$0	$0	$0	$0
Subtotal	**$32,188**	**$15,267**	**$3,697**	**$13,058**	**$110**	**$35**	**$22**
Acct 1830-5 Secondary Poles, Towers & Fixtures	$2,445,640	$1,442,811	$262,811	$601,585	$111,307	$21,852	$5,274
Acct 1835-5 Secondary Overhead Conductors	$2,048,135	$1,208,302	$220,095	$503,806	$93,216	$18,300	$4,417
Acct 1840-5 Secondary Underground Conduit	$244,542	$144,268	$26,279	$60,153	$11,130	$2,185	$527
Acct 1845-5 Secondary Underground Conductors	$1,506,443	$888,729	$161,884	$370,559	$68,562	$13,460	$3,249
Subtotal	**$6,244,760**	**$3,684,110**	**$671,068**	**$1,536,102**	**$284,214**	**$55,798**	**$13,468**
<u>Operations and Maintenance</u>							
Acct 5020 Overhead Distribution Lines & Feeders - Labour	$48,025	$27,853	$5,025	$12,431	$2,185	$429	$104
Acct 5025 Overhead Distribution Lines & Feeders - Other	$22,235	$12,895	$2,326	$5,755	$1,011	$199	$48
Acct 5040 Underground Distribution Lines & Feeders - Labour	$85,572	$49,807	$9,006	$21,918	$3,893	$764	$184
Acct 5045 Underground Distribution Lines & Feeders - Other	$952	$554	$100	$244	$43	$8	$2
Acct 5090 Underground Distribution Lines & Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0
Acct 5095 Overhead Distribution Lines & Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0
Acct 5120 Maintenance of Poles, Towers & Fixtures	$81,251	$47,125	$8,500	$21,029	$3,696	$725	$175
Acct 5125 Maintenance of Overhead Conductors & Devices	$280,899	$162,903	$29,394	$72,713	$12,777	$2,507	$606
Acct 5135 Overhead Distribution Lines & Feeders - Right of Way	$176,549	$102,392	$18,472	$45,697	$8,031	$1,576	$381
Acct 5145 Maintenance of Underground Conduit	$11,050	$6,445	$1,167	$2,813	$503	$99	$24
Acct 5150 Maintenance of Underground Conductors & Devices	$43,844	$25,512	$4,612	$11,239	$1,994	$391	$95
Total	**$750,378**	**$435,486**	**$78,603**	**$193,838**	**$34,134**	**$6,699**	**$1,618**
<u>General Expenses</u>							
Acct 5005 - Operation Supervision and Engineering	$14,048	$8,038	$1,559	$3,680	$619	$122	$29
Acct 5010 - Load Dispatching	$145,095	$83,022	$16,104	$38,013	$6,396	$1,256	$304
Acct 5085 - Miscellaneous Distribution Expense	$309,633	$177,170	$34,365	$81,121	$13,649	$2,680	$648
Acct 5105 - Maintenance Supervision and Engineering	$42,247	$24,173	$4,689	$11,068	$1,862	$366	$88
Total	**$511,022**	**$292,403**	**$56,717**	**$133,883**	**$22,526**	**$4,424**	**$1,069**
Primary Conductors and Poles Gross Assets	$15,780,159	$9,097,509	$1,636,364	$4,153,886	$717,593	$140,804	$34,004
Acct 1815 - 1855	$36,395,749	$21,248,484	$3,982,287	$8,980,221	$1,756,945	$344,423	$83,388

Grouping of Operation and Maintenance	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
1830	$ 81,251	$ 47,125	$ 8,500	$ 21,029	$ 3,696	$ 725	$ 175
1835	$ 280,899	$ 162,903	$ 29,394	$ 72,713	$ 12,777	$ 2,507	$ 606
1840	$ 11,050	$ 6,445	$ 1,167	$ 2,813	$ 503	$ 99	$ 24
1845	$ 43,844	$ 25,512	$ 4,612	$ 11,239	$ 1,994	$ 391	$ 95
1830 & 1835	$ 246,809	$ 143,140	$ 25,823	$ 63,883	$ 11,227	$ 2,203	$ 532
1840 & 1845	$ 86,524	$ 50,361	$ 9,106	$ 22,162	$ 3,936	$ 772	$ 187
Total	**$ 750,378**	**$ 435,486**	**$ 78,603**	**$ 193,838**	**$ 34,134**	**$ 6,699**	**$ 1,618**

2006 COST ALLOCATION INFORMATION FILING
Canadian Niagara Power Inc - Fort Erie & EOP

Monday, July 14, 2008
Sheet O3.4 Secondary Cost Pool Worksheet - Second Run

ALLOCATION BY RATE CLASSIFICATION

Description	Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
Depreciation on Acct 1830-5 Secondary Poles, Towers & Fixtures	$99,423	$58,655	$10,684	$24,456	$4,525	$888	$214
Depreciation on Acct 1835-5 Secondary Overhead Conductors	$80,471	$47,474	$8,647	$19,794	$3,662	$719	$174
Depreciation on Acct 1840-5 Secondary Underground Conduit	$3,897	$2,299	$419	$959	$177	$35	$8
Depreciation on Acct 1845-5 Secondary Underground Conductors	$63,752	$37,611	$6,851	$15,682	$2,902	$570	$137
Depreciation on General Plant Assigned to Secondary C&P	$55,061	$32,484	$5,888	$13,576	$2,503	$491	$118
Secondary C&P Operations and Maintenance	$212,448	$125,373	$22,823	$52,210	$9,683	$1,901	$459
Allocation of General Expenses	$87,690	$50,698	$9,558	$22,901	$3,644	$717	$173
Admin and General Assigned to Primary C&P	$151,268	$88,197	$16,106	$38,099	$7,154	$1,404	$308
PILs on Secondary C&P	$20,742	$12,237	$2,229	$5,102	$944	$185	$45
Debt Return on Secondary C&P	$149,522	$88,211	$16,068	$36,780	$6,805	$1,336	$322
Equity Return on Secondary C&P	$189,749	$111,943	$20,391	$46,675	$8,636	$1,695	$409
Total	**$1,114,023**	**$655,180**	**$119,663**	**$276,235**	**$50,635**	**$9,941**	**$2,369**
General Plant - Gross Assets	$5,415,496	$3,144,576	$605,633	$1,362,907	$242,821	$47,758	$11,800
General Plant - Accumulated Depreciation	($2,793,148)	($1,621,876)	($312,367)	($702,946)	($125,240)	($24,632)	($6,086)
General Plant - Net Fixed Assets	$2,622,348	$1,522,699	$293,266	$659,961	$117,581	$23,126	$5,714
General Plant - Depreciation	$433,777	$251,878	$48,511	$109,168	$19,450	$3,825	$945
Total Net Fixed Assets Excluding General Plant	**$25,623,982**	**$14,878,403**	**$2,879,715**	**$6,433,393**	**$1,150,202**	**$226,259**	**$56,010**
Total Administration and General Expense	**$2,387,875**	**$1,555,981**	**$287,247**	**$441,901**	**$70,799**	**$14,005**	**$17,942**
Total O&M	**$3,365,935**	**$2,211,845**	**$407,053**	**$605,561**	**$95,823**	**$18,968**	**$26,684**
Secondary Conductors and Poles Gross Plant							
Acct 1830-5 Secondary Poles, Towers & Fixtures	$2,445,640	$1,442,811	$262,811	$601,585	$111,307	$21,852	$5,274
Acct 1835-5 Secondary Overhead Conductors	$2,048,135	$1,208,302	$220,095	$503,806	$93,216	$18,300	$4,417
Acct 1840-5 Secondary Underground Conduit	$244,542	$144,268	$26,279	$60,153	$11,130	$2,185	$527
Acct 1845-5 Secondary Underground Conductors	$1,506,443	$888,729	$161,884	$370,559	$68,562	$13,460	$3,249
Subtotal	***$6,244,760***	***$3,684,110***	***$671,068***	***$1,536,102***	***$284,214***	***$55,798***	***$13,468***
Secondary Conductors and Poles Accumulated Depreciation							
Acct 1830-5 Secondary Poles, Towers & Fixtures	($1,094,567)	($645,742)	($117,623)	($269,244)	($49,816)	($9,780)	($2,361)
Acct 1835-5 Secondary Overhead Conductors	($1,260,740)	($743,776)	($135,480)	($310,120)	($57,379)	($11,265)	($2,719)
Acct 1840-5 Secondary Underground Conduit	($46,867)	($27,649)	($5,036)	($11,528)	($2,133)	($419)	($101)
Acct 1845-5 Secondary Underground Conductors	($590,100)	($348,131)	($63,413)	($145,154)	($26,857)	($5,273)	($1,273)
Subtotal	***($2,992,274)***	***($1,765,299)***	***($321,553)***	***($736,047)***	***($136,186)***	***($26,736)***	***($6,453)***
Secondary Conductor & Pools - Net Fixed Assets	$3,252,486	$1,918,812	$349,515	$800,055	$148,029	$29,062	$7,014
General Plant Assigned to Secondary C&P - NFA	$332,862	$196,377	$35,594	$82,073	$15,132	$2,970	$716
Secondary C&P Net Fixed Assets Including General Plant	$3,585,348	$2,115,188	$385,109	$882,127	$163,161	$32,032	$7,730
Acct 1830-3 Bulk Poles, Towers & Fixtures	$26,530	$12,584	$3,047	$10,762	$90	$29	$18
Acct 1835-3 Bulk Overhead Conductors	$5,658	$2,684	$650	$2,295	$19	$6	$4
Acct 1840-3 Bulk Underground Conduit	$0	$0	$0	$0	$0	$0	$0
Acct 1845-3 Bulk Underground Conductors	$0	$0	$0	$0	$0	$0	$0
Subtotal	***$32,188***	***$15,267***	***$3,697***	***$13,058***	***$110***	***$35***	***$22***
Acct 1830-4 Primary Poles, Towers & Fixtures	$7,229,346	$4,167,831	$749,666	$1,903,015	$328,750	$64,506	$15,578
Acct 1835-4 Primary Overhead Conductors	$6,049,294	$3,487,513	$627,297	$1,592,384	$275,088	$53,977	$13,035
Acct 1840-4 Primary Underground Conduit	$241,813	$139,409	$25,075	$63,654	$10,996	$2,158	$521
Acct 1845-4 Primary Underground Conductors	$2,259,706	$1,302,756	$234,326	$594,833	$102,759	$20,163	$4,869
Subtotal	***$15,780,159***	***$9,097,509***	***$1,636,364***	***$4,153,886***	***$717,593***	***$140,804***	***$34,004***
Operations and Maintenance							
Acct 5020 Overhead Distribution Lines & Feeders - Labour	$48,025	$27,853	$5,025	$12,431	$2,185	$429	$104
Acct 5025 Overhead Distribution Lines & Feeders - Other	$22,235	$12,895	$2,326	$5,755	$1,011	$199	$48
Acct 5040 Underground Distribution Lines & Feeders - Labour	$85,572	$49,807	$9,006	$21,918	$3,893	$764	$184
Acct 5045 Underground Distribution Lines & Feeders - Other	$952	$554	$100	$244	$43	$8	$2
Acct 5090 Underground Distribution Lines & Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0
Acct 5095 Overhead Distribution Lines & Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0
Acct 5120 Maintenance of Poles, Towers & Fixtures	$81,251	$47,125	$8,500	$21,029	$3,696	$725	$175
Acct 5125 Maintenance of Overhead Conductors & Devices	$280,899	$162,903	$29,394	$72,713	$12,777	$2,507	$606
Acct 5135 Overhead Distribution Lines & Feeders - Right of Way	$176,549	$102,392	$18,472	$45,697	$8,031	$1,576	$381
Acct 5145 Maintenance of Underground Conduit	$11,050	$6,445	$1,167	$2,813	$503	$99	$24
Acct 5150 Maintenance of Underground Conductors & Devices	$43,844	$25,512	$4,612	$11,239	$1,994	$391	$95
Total	**$750,378**	**$435,486**	**$78,603**	**$193,838**	**$34,134**	**$6,699**	**$1,618**
General Expenses							
Acct 5005 - Operation Supervision and Engineering	$14,048	$8,038	$1,559	$3,680	$619	$122	$29
Acct 5010 - Load Dispatching	$145,095	$83,022	$16,104	$38,013	$6,396	$1,256	$304
Acct 5085 - Miscellaneous Distribution Expense	$309,633	$177,170	$34,365	$81,121	$13,649	$2,680	$648
Acct 5105 - Maintenance Supervision and Engineering	$42,247	$24,173	$4,689	$11,068	$1,862	$366	$88
Total	**$511,022**	**$292,403**	**$56,717**	**$133,883**	**$22,526**	**$4,424**	**$1,069**
Secondary Conductors and Poles Gross Assets	$6,244,760	$3,684,110	$671,068	$1,536,102	$284,214	$55,798	$13,468
Acct 1815 - 1855	$36,395,749	$21,248,484	$3,982,287	$8,980,221	$1,756,945	$344,423	$83,388

Grouping of Operation and Maintenance	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
1830	$ 81,251	$ 47,125	$ 8,500	$ 21,029	$ 3,696	$ 725	$ 175
1835	$ 280,899	$ 162,903	$ 29,394	$ 72,713	$ 12,777	$ 2,507	$ 606
1840	$ 11,050	$ 6,445	$ 1,167	$ 2,813	$ 503	$ 99	$ 24
1845	$ 43,844	$ 25,512	$ 4,612	$ 11,239	$ 1,994	$ 391	$ 95
1830 & 1835	$ 246,809	$ 143,140	$ 25,823	$ 63,883	$ 11,227	$ 2,203	$ 532
1840 & 1845	$ 86,524	$ 50,361	$ 9,106	$ 22,162	$ 3,936	$ 772	$ 187
Total	**$ 750,378**	**$ 435,486**	**$ 78,603**	**$ 193,838**	**$ 34,134**	**$ 6,699**	**$ 1,618**

ALLOCATION BY RATE CLASSIFICATION

Description	GS <50
Depreciation on Acct 1860 Metering	$11,372
Depreciation on General Plant Assigned to Metering	$2,512
Acct 5065 - Meter expense	$19,899
Acct 5070 & 5075 - Customer Premises	$812
Acct 5175 - Meter Maintenance	$9,374
Acct 5310 - Meter Reading	$38,558
Admin and General Assigned to Metering	$48,440
PILs on Metering	$951
Debt Return on Metering	$6,855
Equity Return on Metering	$8,700
Total	$147,473
Number of Customers	1,539
Metering Unit Cost ($/Customer/Month)	**$7.99**
General Plant - Gross Assets	$605,633
General Plant - Accumulated Depreciation	($312,367)
General Plant - Net Fixed Assets	$293,266
General Plant - Depreciation	$48,511
Total Net Fixed Assets Excluding General Plant	$2,879,715
Total Administration and General Expense	$287,247
Total O&M	$407,053
Metering Rate Base	
Acct 1860 - Metering - Gross Assets	$308,605
Metering - Accumulated Depreciation	($159,484)
Metering - Net Fixed Assets	$149,121
General Plant Assigned to Metering - NFA	$15,186
Metering Net Fixed Assets Including General Plant	$164,307

2006 COST ALLOCATION INFORMATION FILING
Canadian Niagara Power Inc - Fort Erie & EOP

Monday, July 14, 2008
Sheet O4 Summary of Allocators by Class & Accounts - Second Run

ALLOCATION BY RATE CLASSIFICATION

				1	2	3	7	8	9
USoA Account #	Accounts	O1 Grouping	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
1565	Conservation and Demand Management Expenditures and Recoveries	dp	$0	$0	$0	$0	$0	$0	$0
1608	Franchises and Consents	gp	$0	$0	$0	$0	$0	$0	$0
1805	Land	dp	$0	$0	$0	$0	$0	$0	$0
1805-1	Land Station >50 kV	dp	$0	$0	$0	$0	$0	$0	$0
1805-2	Land Station <50 kV	dp	$0	$0	$0	$0	$0	$0	$0
1806	Land Rights	dp	$0	$0	$0	$0	$0	$0	$0
1806-1	Land Rights Station >50 kV	dp	$0	$0	$0	$0	$0	$0	$0
1806-2	Land Rights Station <50 kV	dp	$104,138	$49,395	$11,962	$42,245	$354	$112	$70
1808	Buildings and Fixtures	dp	$0	$0	$0	$0	$0	$0	$0
1808-1	Buildings and Fixtures > 50 kV	dp	$0	$0	$0	$0	$0	$0	$0
1808-2	Buildings and Fixtures < 50 KV	dp	$2,845,621	$1,349,734	$326,853	$1,154,370	$9,683	$3,063	$1,917
1810	Leasehold Improvements	dp	$0	$0	$0	$0	$0	$0	$0
1810-1	Leasehold Improvements >50 kV	dp	$0	$0	$0	$0	$0	$0	$0
1810-2	Leasehold Improvements <50 kV	dp	$0	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment - Normally Primary above 50 kV	dp	$0	$0	$0	$0	$0	$0	$0
1820	Distribution Station Equipment - Normally Primary below 50 kV	dp	$0	$0	$0	$0	$0	$0	$0
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	dp	$229,590	$108,899	$26,371	$93,137	$781	$247	$155
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	dp	$2,713,055	$1,196,642	$339,624	$1,176,340	$0	$449	$0
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	dp	$0	$0	$0	$0	$0	$0	$0
1825	Storage Battery Equipment	dp	$0	$0	$0	$0	$0	$0	$0
1825-1	Storage Battery Equipment > 50 kV	dp	$0	$0	$0	$0	$0	$0	$0
1825-2	Storage Battery Equipment <50 kV	dp	$0	$0	$0	$0	$0	$0	$0
1830	Poles, Towers and Fixtures	dp	$0	$0	$0	$0	$0	$0	$0
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	dp	$26,530	$12,584	$3,047	$10,762	$90	$29	$18
1830-4	Poles, Towers and Fixtures - Primary	dp	$7,229,346	$4,167,831	$749,666	$1,903,015	$328,750	$64,506	$15,578
1830-5	Poles, Towers and Fixtures - Secondary	dp	$2,445,640	$1,442,811	$262,811	$601,585	$111,307	$21,852	$5,274
1835	Overhead Conductors and Devices	dp	$0	$0	$0	$0	$0	$0	$0
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	dp	$5,658	$2,684	$650	$2,295	$19	$6	$4
1835-4	Overhead Conductors and Devices - Primary	dp	$6,049,294	$3,487,513	$627,297	$1,592,384	$275,088	$53,977	$13,035
1835-5	Overhead Conductors and Devices - Secondary	dp	$2,048,135	$1,208,302	$220,095	$503,806	$93,216	$18,300	$4,417
1840	Underground Conduit	dp	$0	$0	$0	$0	$0	$0	$0
1840-3	Underground Conduit - Bulk Delivery	dp	$0	$0	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary	dp	$241,813	$139,409	$25,075	$63,654	$10,996	$2,158	$521
1840-5	Underground Conduit - Secondary	dp	$244,542	$144,268	$26,279	$60,153	$11,130	$2,185	$527
1845	Underground Conductors and Devices	dp	$0	$0	$0	$0	$0	$0	$0
1845-3	Underground Conductors and Devices - Bulk Delivery	dp	$0	$0	$0	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary	dp	$2,259,706	$1,302,756	$234,326	$594,833	$102,759	$20,163	$4,869
1845-5	Underground Conductors and Devices - Secondary	dp	$1,506,443	$888,729	$161,884	$370,559	$68,562	$13,460	$3,249

1850	Line Transformers	dp	$7,102,674	$4,190,239	$763,260	$1,747,134	$323,260	$63,464	$15,318
1855	Services	dp	$4,293,321	$2,955,818	$541,903	$260,564	$430,987	$83,627	$20,423
1860	Meters	dp	$2,402,778	$1,476,138	$308,605	$618,035	$0	$0	$0
1905	Land	gp	$0	$0	$0	$0	$0	$0	$0
1906	Land Rights	gp	$0	$0	$0	$0	$0	$0	$0
1908	Buildings and Fixtures	gp	$386,539	$224,449	$43,228	$97,280	$17,332	$3,409	$842
1910	Leasehold Improvements	gp	$0	$0	$0	$0	$0	$0	$0
1915	Office Furniture and Equipment	gp	$1,150,790	$668,220	$128,697	$289,617	$51,599	$10,149	$2,508
1920	Computer Equipment - Hardware	gp	$629,528	$365,543	$70,402	$158,432	$28,227	$5,552	$1,372
1925	Computer Software	gp	$1,351,102	$784,534	$151,098	$340,029	$60,581	$11,915	$2,944
1930	Transportation Equipment	gp	$413,247	$239,957	$46,215	$104,001	$18,529	$3,644	$900
1935	Stores Equipment	gp	$96,772	$56,192	$10,822	$24,354	$4,339	$853	$211
1940	Tools, Shop and Garage Equipment	gp	$623,491	$362,038	$69,727	$156,913	$27,956	$5,498	$1,359
1945	Measurement and Testing Equipment	gp	$296,485	$172,158	$33,157	$74,616	$13,294	$2,615	$646
1950	Power Operated Equipment	gp	$66,375	$38,542	$7,423	$16,705	$2,976	$585	$145
1955	Communication Equipment	gp	$314,169	$182,426	$35,135	$79,066	$14,087	$2,771	$685
1960	Miscellaneous Equipment	gp	$86,998	$50,516	$9,729	$21,895	$3,901	$767	$190
1970	Load Management Controls - Customer Premises	gp	$0	$0	$0	$0	$0	$0	$0
1975	Load Management Controls - Utility Premises	gp	$0	$0	$0	$0	$0	$0	$0
1980	System Supervisory Equipment	gp	$0	$0	$0	$0	$0	$0	$0
1990	Other Tangible Property	gp	$0	$0	$0	$0	$0	$0	$0
1995	Contributions and Grants - Credit	co	($2,197,180)	($1,276,304)	($231,620)	($568,304)	($97,249)	($19,089)	($4,613)
2005	Property Under Capital Leases	gp	$0	$0	$0	$0	$0	$0	$0
2010	Electric Plant Purchased or Sold	gp	$0	$0	$0	$0	$0	$0	$0
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	accum dep	($16,708,331)	($9,583,986)	($1,829,404)	($4,493,115)	($644,236)	($126,777)	($30,813)
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	accum dep	($11,941)	($6,934)	($1,335)	($3,005)	($535)	($105)	($26)
3046	Balance Transferred From Income	NI	($1,494,893)	($868,000)	($168,001)	($375,322)	($67,102)	($13,200)	($3,268)
4080	Distribution Services Revenue	CREV	($9,810,770)	($4,795,124)	($1,533,243)	($3,366,004)	($70,045)	($26,508)	($19,846)
4082	Retail Services Revenues	mi	($6,455)	($5,007)	($918)	($349)	($6)	($2)	($173)
4084	Service Transaction Requests (STR) Revenues	mi	($80)	($62)	($11)	($4)	($0)	($0)	($2)
4090	Electric Services Incidental to Energy Sales	mi	$0	$0	$0	$0	$0	$0	$0
4205	Interdepartmental Rents	mi	$0	$0	$0	$0	$0	$0	$0
4210	Rent from Electric Property	mi	$99,716	$57,900	$11,206	$25,036	$4,476	$880	$218
4215	Other Utility Operating Income	mi	$0	$0	$0	$0	$0	$0	$0
4220	Other Electric Revenues	mi	($133,181)	($77,331)	($14,967)	($33,438)	($5,978)	($1,176)	($291)
4225	Late Payment Charges	mi	($71,821)	($34,479)	($11,724)	($24,796)	($513)	($174)	($136)
4235	Miscellaneous Service Revenues	mi	($442,265)	($343,077)	($62,898)	($23,888)	($388)	($161)	($11,852)
4240	Provision for Rate Refunds	mi	$0	$0	$0	$0	$0	$0	$0
4245	Government Assistance Directly Credited to Income	mi	$0	$0	$0	$0	$0	$0	$0
4305	Regulatory Debits	mi	$0	$0	$0	$0	$0	$0	$0
4310	Regulatory Credits	mi	$0	$0	$0	$0	$0	$0	$0
4315	Revenues from Electric Plant Leased to Others	mi	$0	$0	$0	$0	$0	$0	$0
4320	Expenses of Electric Plant Leased to Others	mi	$0	$0	$0	$0	$0	$0	$0
4325	Revenues from Merchandise, Jobbing, Etc.	mi	($1,695)	($984)	($191)	($426)	($76)	($15)	($4)
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	mi	($28,338)	($16,455)	($3,185)	($7,115)	($1,272)	($250)	($62)
4335	Profits and Losses from Financial Instrument Hedges	mi	$0	$0	$0	$0	$0	$0	$0
4340	Profits and Losses from Financial Instrument Investments	mi	$0	$0	$0	$0	$0	$0	$0
4345	Gains from Disposition of Future Use Utility Plant	mi	$0	$0	$0	$0	$0	$0	$0
4350	Losses from Disposition of Future Use Utility Plant	mi	$0	$0	$0	$0	$0	$0	$0
4355	Gain on Disposition of Utility and Other Property	mi	$0	$0	$0	$0	$0	$0	$0
4360	Loss on Disposition of Utility and Other Property	mi	$11,503	$6,679	$1,293	$2,888	$516	$102	$25

4365	Gains from Disposition of Allowances for Emission	mi	$0	$0	$0	$0	$0	$0	$0
4370	Losses from Disposition of Allowances for Emission	mi	$0	$0	$0	$0	$0	$0	$0
4390	Miscellaneous Non-Operating Income	mi	$0	$0	$0	$0	$0	$0	$0
4395	Rate-Payer Benefit Including Interest	mi	$0	$0	$0	$0	$0	$0	$0
4398	Foreign Exchange Gains and Losses, Including Amortization	mi	($22,682)	($13,170)	($2,549)	($5,695)	($1,018)	($200)	($50)
4405	Interest and Dividend Income	mi	$77,395	$44,939	$8,698	$19,432	$3,474	$683	$169
4415	Equity in Earnings of Subsidiary Companies	mi	$0	$0	$0	$0	$0	$0	$0
4705	Power Purchased	cop	$18,583,495	$6,738,782	$2,711,793	$8,954,346	$117,679	$41,939	$18,957
4708	Charges-WMS	cop	$2,242,395	$813,141	$327,221	$1,080,484	$14,200	$5,061	$2,287
4710	Cost of Power Adjustments	cop	$963,849	$349,513	$140,650	$464,425	$6,104	$2,175	$983
4712	Charges-One-Time	cop	$0	$0	$0	$0	$0	$0	$0
4714	Charges-NW	cop	$2,481,440	$899,824	$362,104	$1,195,667	$15,714	$5,600	$2,531
4715	System Control and Load Dispatching	cop	$0	$0	$0	$0	$0	$0	$0
4716	Charges-CN	cop	$2,228,634	$808,152	$325,213	$1,073,854	$14,113	$5,030	$2,273
4730	Rural Rate Assistance Expense	cop	$0	$0	$0	$0	$0	$0	$0
5005	Operation Supervision and Engineering	di	$14,048	$8,038	$1,559	$3,680	$619	$122	$29
5010	Load Dispatching	di	$145,095	$83,022	$16,104	$38,013	$6,396	$1,256	$304
5012	Station Buildings and Fixtures Expense	di	$94,038	$44,604	$10,801	$38,148	$320	$101	$63
5014	Transformer Station Equipment - Operation Labour	di	$0	$0	$0	$0	$0	$0	$0
5015	Transformer Station Equipment - Operation Supplies and Expenses	di	$0	$0	$0	$0	$0	$0	$0
5016	Distribution Station Equipment - Operation Labour	di	$51,573	$22,881	$6,414	$22,249	$14	$12	$3
5017	Distribution Station Equipment - Operation Supplies and Expenses	di	$3,978	$1,765	$495	$1,716	$1	$1	$0
5020	Overhead Distribution Lines and Feeders - Operation Labour	di	$48,025	$27,853	$5,025	$12,431	$2,185	$429	$104
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	di	$22,235	$12,895	$2,326	$5,755	$1,011	$199	$48
5030	Overhead Subtransmission Feeders - Operation	di	$0	$0	$0	$0	$0	$0	$0
5035	Overhead Distribution Transformers- Operation	di	$51,894	$30,615	$5,577	$12,765	$2,362	$464	$112
5040	Underground Distribution Lines and Feeders - Operation Labour	di	$85,572	$49,807	$9,006	$21,918	$3,893	$764	$184
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	di	$952	$554	$100	$244	$43	$8	$2
5050	Underground Subtransmission Feeders - Operation	di	$0	$0	$0	$0	$0	$0	$0
5055	Underground Distribution Transformers - Operation	di	$15,178	$8,954	$1,631	$3,734	$691	$136	$33
5065	Meter Expense	cu	$154,933	$95,183	$19,899	$39,851	$0	$0	$0
5070	Customer Premises - Operation Labour	cu	$1,955	$1,524	$140	$15	$222	$43	$11
5075	Customer Premises - Materials and Expenses	cu	$9,406	$7,334	$672	$73	$1,069	$207	$51
5085	Miscellaneous Distribution Expense	di	$309,633	$177,170	$34,365	$81,121	$13,649	$2,680	$648
5090	Underground Distribution Lines and Feeders - Rental Paid	di	$0	$0	$0	$0	$0	$0	$0
5095	Overhead Distribution Lines and Feeders - Rental Paid	di	$0	$0	$0	$0	$0	$0	$0
5096	Other Rent	di	$2,135	$1,403	$258	$384	$61	$12	$17
5105	Maintenance Supervision and Engineering	di	$42,247	$24,173	$4,689	$11,068	$1,862	$366	$88
5110	Maintenance of Buildings and Fixtures - Distribution Stations	di	$5,324	$2,525	$612	$2,160	$18	$6	$4
5112	Maintenance of Transformer Station Equipment	di	$0	$0	$0	$0	$0	$0	$0
5114	Maintenance of Distribution Station Equipment	di	$35,608	$15,798	$4,429	$15,362	$9	$8	$2
5120	Maintenance of Poles, Towers and Fixtures	di	$81,251	$47,125	$8,500	$21,029	$3,696	$725	$175
5125	Maintenance of Overhead Conductors and Devices	di	$280,899	$162,903	$29,394	$72,713	$12,777	$2,507	$606
5130	Maintenance of Overhead Services	di	$211,250	$145,439	$26,664	$12,821	$21,206	$4,115	$1,005
5135	Overhead Distribution Lines and Feeders - Right of Way	di	$176,549	$102,392	$18,472	$45,697	$8,031	$1,576	$381
5145	Maintenance of Underground Conduit	di	$11,050	$6,445	$1,167	$2,813	$503	$99	$24
5150	Maintenance of Underground Conductors and Devices	di	$43,844	$25,512	$4,612	$11,239	$1,994	$391	$95

5155	Maintenance of Underground Services	di	$33,617	$23,144	$4,243	$2,040	$3,375	$655	$160
5160	Maintenance of Line Transformers	di	$201,067	$118,620	$21,607	$49,459	$9,151	$1,797	$434
5175	Maintenance of Meters	cu	$72,986	$44,839	$9,374	$18,773	$0	$0	$0
5305	Supervision	cu	$0	$0	$0	$0	$0	$0	$0
5310	Meter Reading Expense	cu	$244,533	$191,885	$38,558	$14,090	$0	$0	$0
5315	Customer Billing	cu	$348,370	$270,240	$49,544	$18,817	$306	$127	$9,336
5320	Collecting	cu	$114,921	$89,148	$16,344	$6,207	$101	$42	$3,080
5325	Collecting- Cash Over and Short	cu	$626	$485	$89	$34	$1	$0	$17
5330	Collection Charges	cu	$4,262	$3,306	$606	$230	$4	$2	$114
5335	Bad Debt Expense	cu	$91,750	$88,525	$3,225	$0	$0	$0	$0
5340	Miscellaneous Customer Accounts Expenses	cu	$357,265	$277,140	$50,809	$19,297	$314	$130	$9,574
5405	Supervision	ad	$0	$0	$0	$0	$0	$0	$0
5410	Community Relations - Sundry	ad	$0	$0	$0	$0	$0	$0	$0
5415	Energy Conservation	ad	$0	$0	$0	$0	$0	$0	$0
5420	Community Safety Program	ad	$0	$0	$0	$0	$0	$0	$0
5425	Miscellaneous Customer Service and Informational Expenses	ad	$0	$0	$0	$0	$0	$0	$0
5505	Supervision	ad	$0	$0	$0	$0	$0	$0	$0
5510	Demonstrating and Selling Expense	ad	$0	$0	$0	$0	$0	$0	$0
5515	Advertising Expense	ad	$0	$0	$0	$0	$0	$0	$0
5520	Miscellaneous Sales Expense	ad	$0	$0	$0	$0	$0	$0	$0
5605	Executive Salaries and Expenses	ad	$1,063,679	$698,971	$128,634	$191,365	$30,281	$5,994	$8,433
5610	Management Salaries and Expenses	ad	$0	$0	$0	$0	$0	$0	$0
5615	General Administrative Salaries and Expenses	ad	$1,994,625	$1,310,721	$241,216	$358,850	$56,784	$11,240	$15,813
5620	Office Supplies and Expenses	ad	$577,668	$379,601	$69,859	$103,927	$16,445	$3,255	$4,580
5625	Administrative Expense Transferred Credit	ad	($3,125,910)	($2,054,118)	($378,026)	($562,378)	($88,990)	($17,616)	($24,781)
5630	Outside Services Employed	ad	$232,930	$153,064	$28,169	$41,906	$6,631	$1,313	$1,847
5635	Property Insurance	ad	$100,616	$58,424	$11,252	$25,322	$4,511	$887	$219
5640	Injuries and Damages	ad	$125	$82	$15	$22	$4	$1	$1
5645	Employee Pensions and Benefits	ad	$404,529	$265,827	$48,921	$72,778	$11,516	$2,280	$3,207
5650	Franchise Requirements	ad	$0	$0	$0	$0	$0	$0	$0
5655	Regulatory Expenses	ad	$88,458	$58,128	$10,697	$15,914	$2,518	$498	$701
5660	General Advertising Expenses	ad	$6,402	$4,207	$774	$1,152	$182	$36	$51
5665	Miscellaneous General Expenses	ad	$245,884	$161,577	$29,736	$44,237	$7,000	$1,386	$1,949
5670	Rent	ad	$350,519	$230,335	$42,389	$63,061	$9,979	$1,975	$2,779
5675	Maintenance of General Plant	ad	$376,947	$247,702	$45,585	$67,816	$10,731	$2,124	$2,988
5680	Electrical Safety Authority Fees	ad	$0	$0	$0	$0	$0	$0	$0
5685	Independent Market Operator Fees and Penalties	cop	$0	$0	$0	$0	$0	$0	$0
5705	Amortization Expense - Property, Plant, and Equipment	dep	$1,678,905	$968,847	$183,164	$441,452	$68,673	$13,496	$3,273
5710	Amortization of Limited Term Electric Plant	dep	$0	$0	$0	$0	$0	$0	$0
5715	Amortization of Intangibles and Other Electric Plant	dep	$5,746	$3,336	$643	$1,446	$258	$51	$13
5720	Amortization of Electric Plant Acquisition Adjustments	dep	$0	$0	$0	$0	$0	$0	$0
5730	Amortization of Unrecovered Plant and Regulatory Study Costs	dep	$0	$0	$0	$0	$0	$0	$0
5735	Amortization of Deferred Development Costs	dep	$0	$0	$0	$0	$0	$0	$0
5740	Amortization of Deferred Charges	dep	$0	$0	$0	$0	$0	$0	$0
6005	Interest on Long Term Debt	INT	$1,177,975	$683,984	$132,385	$295,753	$52,877	$10,402	$2,575
6105	Taxes Other Than Income Taxes	ad	$71,404	$41,460	$8,025	$17,927	$3,205	$630	$156
6110	Income Taxes	Input	$163,414	$94,885	$18,365	$41,028	$7,335	$1,443	$357
6205	Donations	ad	$0	$0	$0	$0	$0	$0	$0

6210	Life Insurance	ad	$0	$0	$0	$0	$0	$0	$0
6215	Penalties	ad	$0	$0	$0	$0	$0	$0	$0
6225	Other Deductions	ad	$0	$0	$0	$0	$0	$0	$0
			$51,704,561	**$25,486,625**	**$6,292,587**	**$17,899,976**	**$1,593,485**	**$327,544**	**$104,345**
				$51,704,561					

Grouping by Allocator	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
1808	$ 99,362	$ 47,129	$ 11,413	$ 40,308	$ 338	$ 107	$ 67
1815	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1820	$ 91,160	$ 40,444	$ 11,338	$ 39,327	$ 24	$ 22	$ 5
1830	$ 81,251	$ 47,125	$ 8,500	$ 21,029	$ 3,696	$ 725	$ 175
1835	$ 280,899	$ 162,903	$ 29,394	$ 72,713	$ 12,777	$ 2,507	$ 606
1840	$ 11,050	$ 6,445	$ 1,167	$ 2,813	$ 503	$ 99	$ 24
1845	$ 43,844	$ 25,512	$ 4,612	$ 11,239	$ 1,994	$ 391	$ 95
1850	$ 268,139	$ 158,189	$ 28,814	$ 65,958	$ 12,204	$ 2,396	$ 578
1855	$ 244,866	$ 168,583	$ 30,907	$ 14,861	$ 24,581	$ 4,770	$ 1,165
1860	$ 72,986	$ 44,839	$ 9,374	$ 18,773	$ -	$ -	$ -
1815-1855	$ 511,022	$ 292,403	$ 56,717	$ 133,883	$ 22,526	$ 4,424	$ 1,069
1830 & 1835	$ 246,809	$ 143,140	$ 25,823	$ 63,883	$ 11,227	$ 2,203	$ 532
1840 & 1845	$ 86,524	$ 50,361	$ 9,106	$ 22,162	$ 3,936	$ 772	$ 187
BCP	$ 32,188	$ 15,267	$ 3,697	$ 13,058	$ 110	$ 35	$ 22
BDHA	$ 91,750	$ 88,525	$ 3,225	$ -	$ -	$ -	$ -
Break Out	-$ 17,232,801	-$ 9,895,040	-$ 1,878,553	-$ 4,621,527	-$ 673,090	-$ 132,424	-$ 32,167
CCA	$ 11,361	$ 8,858	$ 812	$ 88	$ 1,292	$ 251	$ 61
CDMPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEN	$ 4,710,074	$ 1,707,976	$ 687,317	$ 2,269,521	$ 29,826	$ 10,630	$ 4,805
CEN EWMP	$ 21,789,738	$ 7,901,436	$ 3,179,664	$ 10,499,255	$ 137,982	$ 49,174	$ 22,227
CREV	-$ 9,810,770	-$ 4,795,124	-$ 1,533,243	-$ 3,366,004	-$ 70,045	-$ 26,508	-$ 19,846
CWCS	$ 4,293,321	$ 2,955,818	$ 541,903	$ 260,564	$ 430,987	$ 83,627	$ 20,423
CWMC	$ 2,557,711	$ 1,571,320	$ 328,504	$ 657,887	$ -	$ -	$ -
CWMR	$ 244,533	$ 191,885	$ 38,558	$ 14,090	$ -	$ -	$ -
CWNB	$ 376,644	$ 292,173	$ 53,565	$ 20,344	$ 331	$ 137	$ 10,094
DCP	$ 3,179,350	$ 1,508,028	$ 365,186	$ 1,289,752	$ 10,819	$ 3,422	$ 2,142
LPHA	-$ 71,821	-$ 34,479	-$ 11,724	-$ 24,796	-$ 513	-$ 174	-$ 136
LTNCP	$ 7,102,674	$ 4,190,239	$ 763,260	$ 1,747,134	$ 323,260	$ 63,464	$ 15,318
NFA	-$ 79,382	-$ 46,093	-$ 8,921	-$ 19,930	-$ 3,563	-$ 701	-$ 174
NFA ECC	$ 5,516,112	$ 3,203,000	$ 616,886	$ 1,388,229	$ 247,333	$ 48,645	$ 12,020
O&M	$ 2,217,990	$ 1,457,500	$ 268,229	$ 399,036	$ 63,143	$ 12,499	$ 17,584
PNCP	$ 18,493,215	$ 10,294,151	$ 1,975,988	$ 5,330,226	$ 717,593	$ 141,253	$ 34,004
SNCP	$ 6,244,760	$ 3,684,110	$ 671,068	$ 1,536,102	$ 284,214	$ 55,798	$ 13,468
TCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Total	**$**	**51,704,561**	**$**	**25,486,625**	**$**	**6,292,587**	**$**	**17,899,976**	**$**	**1,593,485**	**$**	**327,544**	**$**	**104,345**

2006 COST ALLOCATION INFORMATION FILING
Canadian Niagara Power Inc - Fort Erie & EOP

Monday, July 14, 2008
Sheet O5 Details of Allocators by Class and Account Worksheet - Second Run

Uniform System of Accounts - Detail Accounts

					Categorization			Allocation - Demand Related 1	2	3	7	8	9	
USoA Account #	Accounts	Reclassified Balance	Financial Statement - Asset Break Out includes Acc Dep and Contributed Capital	Adjusted TB	Demand	Customer	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Total - Demand
1565	Conservation and Demand Managemen Expenditures and Recoveries	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1608	Franchises and Consents	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805-1	Land Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805-2	Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806	Land Rights	$104,138	($104,138)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806-1	Land Rights Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806-2	Land Rights Station <50 kV	$0	$104,138	$104,138	$104,138	$0	$104,138	$49,395	$11,962	$42,245	$354	$112	$70	$104,138
1808	Buildings and Fixtures	$2,845,621	($2,845,621)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-2	Buildings and Fixtures < 50 KV	$0	$2,845,621	$2,845,621	$2,845,621	$0	$2,845,621	$1,349,734	$326,853	$1,154,370	$9,683	$3,063	$1,917	$2,845,621
1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810-2	Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820	Distribution Station Equipment - Normally Primary below 50 kV	$2,942,645	($2,942,645)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$229,590	$229,590	$229,590	$0	$229,590	$108,899	$26,371	$93,137	$781	$247	$155	$229,590
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$0	$2,713,055	$2,713,055	$2,713,055	$0	$2,713,055	$1,196,642	$339,624	$1,176,340	$0	$449	$0	$2,713,055
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830	Poles, Towers and Fixtures	$9,701,516	($9,701,516)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$26,530	$26,530	$26,530	$0	$26,530	$12,584	$3,047	$10,762	$90	$29	$18	$26,530
1830-4	Poles, Towers and Fixtures - Primary	$0	$7,229,346	$7,229,346	$4,337,608	$2,891,739	$7,229,346	$1,913,180	$542,988	$1,880,722	$0	$717	$0	$4,337,608
1830-5	Poles, Towers and Fixtures - Secondary	$0	$2,445,640	$2,445,640	$1,467,384	$978,256	$2,445,640	$679,439	$192,835	$594,855	$0	$255	$0	$1,467,384
1835	Overhead Conductors and Devices	$8,103,087	($8,103,087)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$5,658	$5,658	$5,658	$0	$5,658	$2,684	$650	$2,295	$19	$6	$4	$5,658
1835-4	Overhead Conductors and Devices - Primary	$0	$6,049,294	$6,049,294	$3,629,576	$2,419,718	$6,049,294	$1,600,890	$454,356	$1,573,730	$0	$600	$0	$3,629,576
1835-5	Overhead Conductors and Devices - Secondary	$0	$2,048,135	$2,048,135	$1,228,881	$819,254	$2,048,135	$569,006	$161,492	$498,170	$0	$213	$0	$1,228,881
1840	Underground Conduit	$486,355	($486,355)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary	$0	$241,813	$241,813	$145,088	$96,725	$241,813	$63,994	$18,162	$62,908	$0	$24	$0	$145,088
1840-5	Underground Conduit - Secondary	$0	$244,542	$244,542	$146,725	$97,817	$244,542	$67,938	$19,282	$59,480	$0	$25	$0	$146,725
1845	Underground Conductors and Devices	$3,766,149	($3,766,149)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary	$0	$2,259,706	$2,259,706	$1,355,824	$903,882	$2,259,706	$598,010	$169,724	$587,865	$0	$224	$0	$1,355,824
1845-5	Underground Conductors and Devices - Secondary	$0	$1,506,443	$1,506,443	$903,866	$602,577	$1,506,443	$418,515	$118,781	$366,414	$0	$157	$0	$903,866
1850	Line Transformers	$7,102,674	$0	$7,102,674	$4,261,605	$2,841,070	$7,102,674	$1,973,240	$560,034	$1,727,591	$0	$740	$0	$4,261,605
1855	Services	$4,293,321	$0	$4,293,321	$0	$4,293,321	$4,293,321	$0	$0	$0	$0	$0	$0	$0
1860	Meters	$2,402,778	$0	$2,402,778	$0	$2,402,778	$2,402,778	$0	$0	$0	$0	$0	$0	$0
1905	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1906	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1908	Buildings and Fixtures	$386,539	$0	$386,539	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1910	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1915	Office Furniture and Equipment	$1,150,790	$0	$1,150,790	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1920	Computer Equipment - Hardware	$629,528	$0	$629,528	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1925	Computer Software	$1,351,102	$0	$1,351,102	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1930	Transportation Equipment	$413,247	$0	$413,247	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1935	Stores Equipment	$96,772	$0	$96,772	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1940	Tools, Shop and Garage Equipment	$623,491	$0	$623,491	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1945	Measurement and Testing Equipment	$296,485	$0	$296,485	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1950	Power Operated Equipment	$66,375	$0	$66,375	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1955	Communication Equipment	$314,169	$0	$314,169	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1960	Miscellaneous Equipment	$86,998	$0	$86,998	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1970	Load Management Controls - Customer Premises	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1975	Load Management Controls - Utility Premises	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1980	System Supervisory Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1990	Other Tangible Property	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1995	Contributions and Grants - Credit	($2,197,180)		($2,197,180)			$0	($578,617)	($164,032)	($548,970)	($32)	($225)	($6)	($1,291,884)
2005	Property Under Capital Leases	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2010	Electric Plant Purchased or Sold	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	($16,708,331)		($16,708,331)			$0	($3,680,187)	($1,039,303)	($3,453,233)	($893)	($1,615)	($177)	($8,175,408)
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	($11,941)		($11,941)			$0	$0	$0	$0	$0	$0	$0	$0
3046	Balance Transferred From Income	($1,494,893)		($1,494,893)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4080	Distribution Services Revenue	($9,810,770)		($9,810,770)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4082	Retail Services Revenues	($6,455)		($6,455)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4084	Service Transaction Requests (STR) Revenues	($80)		($80)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4090	Electric Services Incidental to Energy Sales	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4205	Interdepartmental Rents	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4210	Rent from Electric Property	$99,716		$99,716	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4215	Other Utility Operating Income	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4220	Other Electric Revenues	($133,181)		($133,181)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4225	Late Payment Charges	($71,821)		($71,821)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4235	Miscellaneous Service Revenue	($442,265)		($442,265)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4240	Provision for Rate Refunds	$0		$0	$0	$0	$0	$0	$0	$0				$0
4245	Government Assistance Directly Credited to Income	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4305	Regulatory Debits	$0		$0	$0	$0	$0	$0	$0	$0				$0
4310	Regulatory Credits	$0		$0	$0	$0	$0	$0	$0	$0				$0
4315	Revenues from Electric Plant Leased to Others	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4320	Expenses of Electric Plant Leased to Others	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4325	Revenues from Merchandise, Jobbing, Etc	($1,695)		($1,695)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4330	Costs and Expenses of Merchandising, Jobbing Etc.	($28,338)		($28,338)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4335	Profits and Losses from Financial Instrument Hedges	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4340	Profits and Losses from Financial Instrument Investments	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4345	Gains from Disposition of Future Use Utility Plant	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4350	Losses from Disposition of Future Use Utility Plant	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4355	Gain on Disposition of Utility and Other Property	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4360	Loss on Disposition of Utility and Other Property	$11,503		$11,503	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4365	Gains from Disposition of Allowances for Emission	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4370	Losses from Disposition of Allowances for Emission	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4390	Miscellaneous Non-Operating Income	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4395	Rate-Payer Benefit Including Interest	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4398	Foreign Exchange Gains and Losses, Including Amortization	($22,682)		($22,682)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4405	Interest and Dividend Income	$77,395		$77,395	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4415	Equity in Earnings of Subsidiary Companies	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4705	Power Purchased	$18,583,495		$18,583,495	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4708	Charges-WMS	$2,242,395		$2,242,395	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4710	Cost of Power Adjustments	$963,849		$963,849	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4712	Charges-One-Time	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4714	Charges-NW	$2,481,440		$2,481,440	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4715	System Control and Load Dispatching	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4716	Charges-CN	$2,228,634		$2,228,634	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4730	Rural Rate Assistance Expense	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5005	Operation Supervision and Engineering	$14,048		$14,048	$8,429	$5,619	$14,048	$3,794	$1,075	$3,558	$0	$2	$0	$8,429
5010	Load Dispatching	$145,095		$145,095	$87,057	$58,038	$145,095	$39,184	$11,099	$36,754	$4	$16	$1	$87,057
5012	Station Buildings and Fixtures Expense	$94,038		$94,038	$94,038	$0	$94,038	$44,604	$10,801	$38,148	$320	$101	$63	$94,038
5014	Transformer Station Equipment - Operation Labour	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5015	Transformer Station Equipment - Operation Supplies and Expenses	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5016	Distribution Station Equipment - Operation Labour	$51,573		$51,573	$51,573	$0	$51,573	$22,881	$6,414	$22,249	$14	$12	$3	$51,573
5017	Distribution Station Equipment - Operation Supplies and Expenses	$3,978		$3,978	$3,978	$0	$3,978	$1,765	$495	$1,716	$1	$1	$0	$3,978
5020	Overhead Distribution Lines and Feeders - Operation Labour	$48,025		$48,025	$28,815	$19,210	$48,025	$12,872	$3,652	$12,287	$0	$5	$0	$28,815
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$22,235		$22,235	$13,341	$8,894	$22,235	$5,959	$1,691	$5,688	$0	$2	$0	$13,341
5030	Overhead Subtransmission Feeders - Operation	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5035	Overhead Distribution Transformers- Operation	$51,894		$51,894	$31,136	$20,758	$51,894	$14,417	$4,092	$12,622	$0	$5	$0	$31,136
5040	Underground Distribution Lines and Feeders - Operation Labour	$85,572		$85,572	$51,343	$34,229	$85,572	$23,110	$6,559	$21,666	$0	$9	$0	$51,343
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$952		$952	$571	$381	$952	$257	$73	$241	$0	$0	$0	$571
5050	Underground Subtransmission Feeders - Operation	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5055	Underground Distribution Transformers - Operation	$15,178		$15,178	$9,107	$6,071	$15,178	$4,217	$1,197	$3,692	$0	$2	$0	$9,107
5065	Meter Expense	$154,933		$154,933	$0	$154,933	$154,933	$0	$0	$0	$0	$0	$0	$0
5070	Customer Premises - Operation Labour	$1,955		$1,955	$0	$1,955	$1,955	$0	$0	$0	$0	$0	$0	$0
5075	Customer Premises - Materials and Expenses	$9,406		$9,406	$0	$9,406	$9,406	$0	$0	$0	$0	$0	$0	$0

	Allocation - Customer Related 1	2	3	7	8	9	
USoA Account #	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Total - Customer
1565	$0	$0	$0	$0	$0	$0	$0
1608	$0	$0	$0	$0	$0	$0	$0
1805	$0	$0	$0	$0	$0	$0	$0
1805-1	$0	$0	$0	$0	$0	$0	$0
1805-2	$0	$0	$0	$0	$0	$0	$0
1806	$0	$0	$0	$0	$0	$0	$0
1806-1	$0	$0	$0	$0	$0	$0	$0
1806-2	$0	$0	$0	$0	$0	$0	$0
1808	$0	$0	$0	$0	$0	$0	$0
1808-1	$0	$0	$0	$0	$0	$0	$0
1808-2	$0	$0	$0	$0	$0	$0	$0
1810	$0	$0	$0	$0	$0	$0	$0
1810-1	$0	$0	$0	$0	$0	$0	$0
1810-2	$0	$0	$0	$0	$0	$0	$0
1815	$0	$0	$0	$0	$0	$0	$0
1820	$0	$0	$0	$0	$0	$0	$0
1820-1	$0	$0	$0	$0	$0	$0	$0
1820-2	$0	$0	$0	$0	$0	$0	$0
1820-3	$0	$0	$0	$0	$0	$0	$0
1825	$0	$0	$0	$0	$0	$0	$0
1825-1	$0	$0	$0	$0	$0	$0	$0
1825-2	$0	$0	$0	$0	$0	$0	$0
1830	$0	$0	$0	$0	$0	$0	$0
1830-3	$0	$0	$0	$0	$0	$0	$0
1830-4	$2,254,651	$206,677	$22,293	$328,750	$63,789	$15,578	$2,891,739
1830-5	$763,372	$69,976	$6,729	$111,307	$21,598	$5,274	$978,256
1835	$0	$0	$0	$0	$0	$0	$0
1835-3	$0	$0	$0	$0	$0	$0	$0
1835-4	$1,886,622	$172,941	$18,654	$275,088	$53,377	$13,035	$2,419,718
1835-5	$639,296	$58,602	$5,636	$93,216	$18,087	$4,417	$819,254
1840	$0	$0	$0	$0	$0	$0	$0
1840-3	$0	$0	$0	$0	$0	$0	$0
1840-4	$75,415	$6,913	$746	$10,996	$2,134	$521	$96,725
1840-5	$76,330	$6,997	$673	$11,130	$2,160	$527	$97,817
1845	$0	$0	$0	$0	$0	$0	$0
1845-3	$0	$0	$0	$0	$0	$0	$0
1845-4	$704,745	$64,602	$6,968	$102,759	$19,939	$4,869	$903,882
1845-5	$470,215	$43,103	$4,145	$68,562	$13,303	$3,249	$602,577
1850	$2,216,998	$203,226	$19,543	$323,260	$62,724	$15,318	$2,841,070
1855	$2,955,818	$541,903	$260,564	$430,987	$83,627	$20,423	$4,293,321
1860	$1,476,138	$308,605	$618,035	$0	$0	$0	$2,402,778
1905	$0	$0	$0	$0	$0	$0	$0
1906	$0	$0	$0	$0	$0	$0	$0
1908	$0	$0	$0	$0	$0	$0	$0
1910	$0	$0	$0	$0	$0	$0	$0
1915	$0	$0	$0	$0	$0	$0	$0
1920	$0	$0	$0	$0	$0	$0	$0
1925	$0	$0	$0	$0	$0	$0	$0
1930	$0	$0	$0	$0	$0	$0	$0
1935	$0	$0	$0	$0	$0	$0	$0
1940	$0	$0	$0	$0	$0	$0	$0
1945	$0	$0	$0	$0	$0	$0	$0
1950	$0	$0	$0	$0	$0	$0	$0
1955	$0	$0	$0	$0	$0	$0	$0
1960	$0	$0	$0	$0	$0	$0	$0
1970	$0	$0	$0	$0	$0	$0	$0
1975	$0	$0	$0	$0	$0	$0	$0
1980	$0	$0	$0	$0	$0	$0	$0
1990	$0	$0	$0	$0	$0	$0	$0
1995	($697,687)	($67,588)	($19,334)	($97,217)	($18,864)	($4,607)	($905,296)
2005	$0	$0	$0	$0	$0	$0	$0
2010	$0	$0	$0	$0	$0	$0	$0
2105	($4,288,857)	($479,069)	($339,941)	($518,638)	($100,635)	($24,576)	($5,751,716)
2120	$0	$0	$0	$0	$0	$0	$0
3046	$0	$0	$0	$0	$0	$0	$0
4080	$0	$0	$0	$0	$0	$0	$0
4082	$0	$0	$0	$0	$0	$0	$0
4084	$0	$0	$0	$0	$0	$0	$0
4090	$0	$0	$0	$0	$0	$0	$0
4205	$0	$0	$0	$0	$0	$0	$0
4210	$0	$0	$0	$0	$0	$0	$0
4215	$0	$0	$0	$0	$0	$0	$0
4220	$0	$0	$0	$0	$0	$0	$0
4225	$0	$0	$0	$0	$0	$0	$0
4235	$0	$0	$0	$0	$0	$0	$0
4240	$0	$0	$0	$0	$0	$0	$0
4245	$0	$0	$0	$0	$0	$0	$0
4305	$0	$0	$0	$0	$0	$0	$0
4310	$0	$0	$0	$0	$0	$0	$0
4315	$0	$0	$0	$0	$0	$0	$0
4320	$0	$0	$0	$0	$0	$0	$0
4325	$0	$0	$0	$0	$0	$0	$0
4330	$0	$0	$0	$0	$0	$0	$0
4335	$0	$0	$0	$0	$0	$0	$0
4340	$0	$0	$0	$0	$0	$0	$0
4345	$0	$0	$0	$0	$0	$0	$0
4350	$0	$0	$0	$0	$0	$0	$0
4355	$0	$0	$0	$0	$0	$0	$0
4360	$0	$0	$0	$0	$0	$0	$0
4365	$0	$0	$0	$0	$0	$0	$0
4370	$0	$0	$0	$0	$0	$0	$0
4390	$0	$0	$0	$0	$0	$0	$0
4395	$0	$0	$0	$0	$0	$0	$0
4398	$0	$0	$0	$0	$0	$0	$0
4405	$0	$0	$0	$0	$0	$0	$0
4415	$0	$0	$0	$0	$0	$0	$0
4705	$0	$0	$0	$0	$0	$0	$0
4708	$0	$0	$0	$0	$0	$0	$0
4710	$0	$0	$0	$0	$0	$0	$0
4712	$0	$0	$0	$0	$0	$0	$0
4714	$0	$0	$0	$0	$0	$0	$0
4715	$0	$0	$0	$0	$0	$0	$0
4716	$0	$0	$0	$0	$0	$0	$0
4730	$0	$0	$0	$0	$0	$0	$0
5005	$4,244	$485	$122	$619	$120	$29	$5,619
5010	$43,839	$5,005	$1,259	$6,392	$1,240	$303	$58,038
5012	$0	$0	$0	$0	$0	$0	$0
5014	$0	$0	$0	$0	$0	$0	$0
5015	$0	$0	$0	$0	$0	$0	$0
5016	$0	$0	$0	$0	$0	$0	$0
5017	$0	$0	$0	$0	$0	$0	$0
5020	$14,981	$1,373	$144	$2,184	$424	$104	$19,210
5025	$6,936	$636	$67	$1,011	$196	$48	$8,894
5030	$0	$0	$0	$0	$0	$0	$0
5035	$16,198	$1,485	$143	$2,362	$458	$112	$20,758
5040	$26,697	$2,447	$252	$3,893	$755	$184	$34,229
5045	$297	$27	$3	$43	$8	$2	$381
5050	$0	$0	$0	$0	$0	$0	$0
5055	$4,738	$434	$42	$691	$134	$33	$6,071
5065	$95,183	$19,899	$39,851	$0	$0	$0	$154,933
5070	$1,524	$140	$15	$222	$43	$11	$1,955
5075	$7,334	$672	$73	$1,069	$207	$51	$9,406

	Allocation of Miscellaneous Revenue 1	2	3	7	8	9	
USoA Account #	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Total - Mis
1565	$0	$0	$0	$0	$0	$0	$0
1608	$0	$0	$0	$0	$0	$0	$0
1805	$0	$0	$0	$0	$0	$0	$0
1805-1	$0	$0	$0	$0	$0	$0	$0
1805-2	$0	$0	$0	$0	$0	$0	$0
1806	$0	$0	$0	$0	$0	$0	$0
1806-1	$0	$0	$0	$0	$0	$0	$0
1806-2	$0	$0	$0	$0	$0	$0	$0
1808	$0	$0	$0	$0	$0	$0	$0
1808-1	$0	$0	$0	$0	$0	$0	$0
1808-2	$0	$0	$0	$0	$0	$0	$0
1810	$0	$0	$0	$0	$0	$0	$0
1810-1	$0	$0	$0	$0	$0	$0	$0
1810-2	$0	$0	$0	$0	$0	$0	$0
1815	$0	$0	$0	$0	$0	$0	$0
1820	$0	$0	$0	$0	$0	$0	$0
1820-1	$0	$0	$0	$0	$0	$0	$0
1820-2	$0	$0	$0	$0	$0	$0	$0
1820-3	$0	$0	$0	$0	$0	$0	$0
1825	$0	$0	$0	$0	$0	$0	$0
1825-1	$0	$0	$0	$0	$0	$0	$0
1825-2	$0	$0	$0	$0	$0	$0	$0
1830	$0	$0	$0	$0	$0	$0	$0
1830-3	$0	$0	$0	$0	$0	$0	$0
1830-4	$0	$0	$0	$0	$0	$0	$0
1830-5	$0	$0	$0	$0	$0	$0	$0
1835	$0	$0	$0	$0	$0	$0	$0
1835-3	$0	$0	$0	$0	$0	$0	$0
1835-4	$0	$0	$0	$0	$0	$0	$0
1835-5	$0	$0	$0	$0	$0	$0	$0
1840	$0	$0	$0	$0	$0	$0	$0
1840-3	$0	$0	$0	$0	$0	$0	$0
1840-4	$0	$0	$0	$0	$0	$0	$0
1840-5	$0	$0	$0	$0	$0	$0	$0
1845	$0	$0	$0	$0	$0	$0	$0
1845-3	$0	$0	$0	$0	$0	$0	$0
1845-4	$0	$0	$0	$0	$0	$0	$0
1845-5	$0	$0	$0	$0	$0	$0	$0
1850	$0	$0	$0	$0	$0	$0	$0
1855	$0	$0	$0	$0	$0	$0	$0
1860	$0	$0	$0	$0	$0	$0	$0
1905	$0	$0	$0	$0	$0	$0	$0
1906	$0	$0	$0	$0	$0	$0	$0
1908	$0	$0	$0	$0	$0	$0	$0
1910	$0	$0	$0	$0	$0	$0	$0
1915	$0	$0	$0	$0	$0	$0	$0
1920	$0	$0	$0	$0	$0	$0	$0
1925	$0	$0	$0	$0	$0	$0	$0
1930	$0	$0	$0	$0	$0	$0	$0
1935	$0	$0	$0	$0	$0	$0	$0
1940	$0	$0	$0	$0	$0	$0	$0
1945	$0	$0	$0	$0	$0	$0	$0
1950	$0	$0	$0	$0	$0	$0	$0
1955	$0	$0	$0	$0	$0	$0	$0
1960	$0	$0	$0	$0	$0	$0	$0
1970	$0	$0	$0	$0	$0	$0	$0
1975	$0	$0	$0	$0	$0	$0	$0
1980	$0	$0	$0	$0	$0	$0	$0
1990	$0	$0	$0	$0	$0	$0	$0
1995							
2005	$0	$0	$0	$0	$0	$0	$0
2010	$0	$0	$0	$0	$0	$0	$0
2105							
2120							
3046	($868,000)	($168,001)	($375,322)	($67,102)	($13,200)	($3,268)	($1,494,893)
4080	($4,795,124)	($1,533,243)	($3,366,004)	($70,045)	($26,508)	($19,846)	($9,810,770)
4082	($5,007)	($918)	($349)	($6)	($2)	($173)	($6,455)
4084	($62)	($11)	($4)	($0)	($0)	($2)	($80)
4090	$0	$0	$0	$0	$0	$0	$0
4205	$0	$0	$0	$0	$0	$0	$0
4210	$57,900	$11,206	$25,036	$4,476	$880	$218	$99,716
4215	$0	$0	$0	$0	$0	$0	$0
4220	($77,331)	($14,967)	($33,438)	($5,978)	($1,176)	($291)	($133,181)
4225	($34,479)	($11,724)	($24,796)	($513)	($174)	($136)	($71,821)
4235	($343,077)	($62,898)	($23,888)	($388)	($161)	($11,852)	($442,265)
4240	$0	$0	$0	$0	$0	$0	$0
4245	$0	$0	$0	$0	$0	$0	$0
4305	$0	$0	$0	$0	$0	$0	$0
4310	$0	$0	$0	$0	$0	$0	$0
4315	$0	$0	$0	$0	$0	$0	$0
4320	$0	$0	$0	$0	$0	$0	$0
4325	($984)	($191)	($426)	($76)	($15)	($4)	($1,695)
4330	($16,455)	($3,185)	($7,115)	($1,272)	($250)	($62)	($28,338)
4335	$0	$0	$0	$0	$0	$0	$0
4340	$0	$0	$0	$0	$0	$0	$0
4345	$0	$0	$0	$0	$0	$0	$0
4350	$0	$0	$0	$0	$0	$0	$0
4355	$0	$0	$0	$0	$0	$0	$0
4360	$6,679	$1,293	$2,888	$516	$102	$25	$11,503
4365	$0	$0	$0	$0	$0	$0	$0
4370	$0	$0	$0	$0	$0	$0	$0
4390	$0	$0	$0	$0	$0	$0	$0
4395	$0	$0	$0	$0	$0	$0	$0
4398	($13,170)	($2,549)	($5,695)	($1,018)	($200)	($50)	($22,682)
4405	$44,939	$8,698	$19,432	$3,474	$683	$169	$77,395
4415	$0	$0	$0	$0	$0	$0	$0
4705	$0	$0	$0	$0	$0	$0	$0
4708	$0	$0	$0	$0	$0	$0	$0
4710	$0	$0	$0	$0	$0	$0	$0
4712	$0	$0	$0	$0	$0	$0	$0
4714	$0	$0	$0	$0	$0	$0	$0
4715	$0	$0	$0	$0	$0	$0	$0
4716	$0	$0	$0	$0	$0	$0	$0
4730	$0	$0	$0	$0	$0	$0	$0
5005	$0	$0	$0	$0	$0	$0	$0
5010	$0	$0	$0	$0	$0	$0	$0
5012	$0	$0	$0	$0	$0	$0	$0
5014	$0	$0	$0	$0	$0	$0	$0
5015	$0	$0	$0	$0	$0	$0	$0
5016	$0	$0	$0	$0	$0	$0	$0
5017	$0	$0	$0	$0	$0	$0	$0
5020	$0	$0	$0	$0	$0	$0	$0
5025	$0	$0	$0	$0	$0	$0	$0
5030	$0	$0	$0	$0	$0	$0	$0
5035	$0	$0	$0	$0	$0	$0	$0
5040	$0	$0	$0	$0	$0	$0	$0
5045	$0	$0	$0	$0	$0	$0	$0
5050	$0	$0	$0	$0	$0	$0	$0
5055	$0	$0	$0	$0	$0	$0	$0
5065	$0	$0	$0	$0	$0	$0	$0
5070	$0	$0	$0	$0	$0	$0	$0
5075	$0	$0	$0	$0	$0	$0	$0

	Allocation of General Plant and Administration 1	2	3	7	8	9		
USoA Account #	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Total - A&G	
1565	$0	$0	$0	$0	$0	$0	$0	$0
1608	$0	$0	$0	$0	$0	$0	$0	$0
1805	$0	$0	$0	$0	$0	$0	$0	$0
1805-1	$0	$0	$0	$0	$0	$0	$0	$0
1805-2	$0	$0	$0	$0	$0	$0	$0	$0
1806	$0	$0	$0	$0	$0	$0	$0	$0
1806-1	$0	$0	$0	$0	$0	$0	$0	$0
1806-2	$0	$0	$0	$0	$0	$0	$0	$0
1808	$0	$0	$0	$0	$0	$0	$0	$0
1808-1	$0	$0	$0	$0	$0	$0	$0	$0
1808-2	$0	$0	$0	$0	$0	$0	$0	$0
1810	$0	$0	$0	$0	$0	$0	$0	$0
1810-1	$0	$0	$0	$0	$0	$0	$0	$0
1810-2	$0	$0	$0	$0	$0	$0	$0	$0
1815	$0	$0	$0	$0	$0	$0	$0	$0
1820	$0	$0	$0	$0	$0	$0	$0	$0
1820-1	$0	$0	$0	$0	$0	$0	$0	($0)
1820-2	$0	$0	$0	$0	$0	$0	$0	$0
1820-3	$0	$0	$0	$0	$0	$0	$0	$0
1825	$0	$0	$0	$0	$0	$0	$0	$0
1825-1	$0	$0	$0	$0	$0	$0	$0	$0
1825-2	$0	$0	$0	$0	$0	$0	$0	$0
1830	$0	$0	$0	$0	$0	$0	$0	$0
1830-3	$0	$0	$0	$0	$0	$0	$0	$0
1830-4	$0	$0	$0	$0	$0	$0	$0	$0
1830-5	$0	$0	$0	$0	$0	$0	$0	$0
1835	$0	$0	$0	$0	$0	$0	$0	$0
1835-3	$0	$0	$0	$0	$0	$0	$0	$0
1835-4	$0	$0	$0	$0	$0	$0	$0	$0
1835-5	$0	$0	$0	$0	$0	$0	$0	($0)
1840	$0	$0	$0	$0	$0	$0	$0	$0
1840-3	$0	$0	$0	$0	$0	$0	$0	$0
1840-4	$0	$0	$0	$0	$0	$0	$0	$0
1840-5	$0	$0	$0	$0	$0	$0	$0	($0)
1845	$0	$0	$0	$0	$0	$0	$0	$0
1845-3	$0	$0	$0	$0	$0	$0	$0	$0
1845-4	$0	$0	$0	$0	$0	$0	$0	($0)
1845-5	$0	$0	$0	$0	$0	$0	$0	($0)
1850	$0	$0	$0	$0	$0	$0	$0	$0
1855	$0	$0	$0	$0	$0	$0	$0	$0
1860	$0	$0	$0	$0	$0	$0	$0	$0
1905	$0	$0	$0	$0	$0	$0	$0	$0
1906	$0	$0	$0	$0	$0	$0	$0	$0
1908	$224,449	$43,228	$97,280	$17,332	$3,409	$842	$386,539	$0
1910	$0	$0	$0	$0	$0	$0	$0	$0
1915	$668,220	$128,697	$289,617	$51,599	$10,149	$2,508	$1,150,790	$0
1920	$365,543	$70,402	$158,432	$28,227	$5,552	$1,372	$629,528	$0
1925	$784,534	$151,098	$340,029	$60,581	$11,915	$2,944	$1,351,102	$0
1930	$239,957	$46,215	$104,001	$18,529	$3,644	$900	$413,247	$0
1935	$56,192	$10,822	$24,354	$4,339	$853	$211	$96,772	$0
1940	$362,038	$69,727	$156,913	$27,956	$5,498	$1,359	$623,491	$0
1945	$172,158	$33,157	$74,616	$13,294	$2,615	$646	$296,485	$0
1950	$38,542	$7,423	$16,705	$2,976	$585	$145	$66,375	$0
1955	$182,426	$35,135	$79,066	$14,087	$2,771	$685	$314,169	$0
1960	$50,516	$9,729	$21,895	$3,901	$767	$190	$86,998	$0
1970	$0	$0	$0	$0	$0	$0	$0	$0
1975	$0	$0	$0	$0	$0	$0	$0	$0
1980	$0	$0	$0	$0	$0	$0	$0	$0
1990	$0	$0	$0	$0	$0	$0	$0	$0
1995	$0	$0	$0	$0	$0	$0	$0	($0)
2005	$0	$0	$0	$0	$0	$0	$0	$0
2010	$0	$0	$0	$0	$0	$0	$0	$0
2105	($1,614,943)	($311,032)	($699,941)	($124,704)	($24,527)	($6,060)	($2,781,207)	($0)
2120	($6,934)	($1,335)	($3,005)	($535)	($105)	($26)	($11,941)	($0)
3046	$0	$0	$0	$0	$0	$0	$0	$0
4080	$0	$0	$0	$0	$0	$0	$0	$0
4082	$0	$0	$0	$0	$0	$0	$0	$0
4084	$0	$0	$0	$0	$0	$0	$0	$0
4090	$0	$0	$0	$0	$0	$0	$0	$0
4205	$0	$0	$0	$0	$0	$0	$0	$0
4210	$0	$0	$0	$0	$0	$0	$0	($0)
4215	$0	$0	$0	$0	$0	$0	$0	$0
4220	$0	$0	$0	$0	$0	$0	$0	$0
4225	$0	$0	$0	$0	$0	$0	$0	($0)
4235	$0	$0	$0	$0	$0	$0	$0	$0
4240	$0	$0	$0	$0	$0	$0	$0	$0
4245	$0	$0	$0	$0	$0	$0	$0	$0
4305	$0	$0	$0	$0	$0	$0	$0	$0
4310	$0	$0	$0	$0	$0	$0	$0	$0
4315	$0	$0	$0	$0	$0	$0	$0	$0
4320	$0	$0	$0	$0	$0	$0	$0	$0
4325	$0	$0	$0	$0	$0	$0	$0	$0
4330	$0	$0	$0	$0	$0	$0	$0	$0
4335	$0	$0	$0	$0	$0	$0	$0	$0
4340	$0	$0	$0	$0	$0	$0	$0	$0
4345	$0	$0	$0	$0	$0	$0	$0	$0
4350	$0	$0	$0	$0	$0	$0	$0	$0
4355	$0	$0	$0	$0	$0	$0	$0	$0
4360	$0	$0	$0	$0	$0	$0	$0	($0)
4365	$0	$0	$0	$0	$0	$0	$0	$0
4370	$0	$0	$0	$0	$0	$0	$0	$0
4390	$0	$0	$0	$0	$0	$0	$0	$0
4395	$0	$0	$0	$0	$0	$0	$0	$0
4398	$0	$0	$0	$0	$0	$0	$0	$0
4405	$0	$0	$0	$0	$0	$0	$0	($0)
4415	$0	$0	$0	$0	$0	$0	$0	$0
4705	$6,738,782	$2,711,793	$8,954,346	$117,679	$41,939	$18,957	$18,583,495	$0
4708	$813,141	$327,221	$1,080,484	$14,200	$5,061	$2,287	$2,242,395	$0
4710	$349,513	$140,650	$464,425	$6,104	$2,175	$983	$963,849	$0
4712	$0	$0	$0	$0	$0	$0	$0	$0
4714	$899,824	$362,104	$1,195,667	$15,714	$5,600	$2,531	$2,481,440	$0
4715	$0	$0	$0	$0	$0	$0	$0	$0
4716	$808,152	$325,213	$1,073,854	$14,113	$5,030	$2,273	$2,228,634	$0
4730	$0	$0	$0	$0	$0	$0	$0	$0
5005	$0	$0	$0	$0	$0	$0	$0	($0)
5010	$0	$0	$0	$0	$0	$0	$0	$0
5012	$0	$0	$0	$0	$0	$0	$0	$0
5014	$0	$0	$0	$0	$0	$0	$0	$0
5015	$0	$0	$0	$0	$0	$0	$0	$0
5016	$0	$0	$0	$0	$0	$0	$0	($0)
5017	$0	$0	$0	$0	$0	$0	$0	($0)
5020	$0	$0	$0	$0	$0	$0	$0	($0)
5025	$0	$0	$0	$0	$0	$0	$0	($0)
5030	$0	$0	$0	$0	$0	$0	$0	$0
5035	$0	$0	$0	$0	$0	$0	$0	($0)
5040	$0	$0	$0	$0	$0	$0	$0	$0
5045	$0	$0	$0	$0	$0	$0	$0	($0)
5050	$0	$0	$0	$0	$0	$0	$0	$0
5055	$0	$0	$0	$0	$0	$0	$0	($0)
5065	$0	$0	$0	$0	$0	$0	$0	$0
5070	$0	$0	$0	$0	$0	$0	$0	$0
5075	$0	$0	$0	$0	$0	$0	$0	$0

5085	Miscellaneous Distribution Expense	$309,633		$309,633	$185,780	$123,853	$309,633	$83,618	$23,685	$78,433	$8	$33	$2
5090	Underground Distribution Lines and Feeders - Rental Paid	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5095	Overhead Distribution Lines and Feeders - Rental Paid	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5096	Other Rent	$2,135		$2,135	$0	$0	$0	$0	$0	$0	$0	$0	$0
5105	Maintenance Supervision and Engineering	$42,247		$42,247	$25,348	$16,899	$42,247	$11,409	$3,232	$10,702	$1	$5	$0
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$5,324		$5,324	$5,324	$0	$5,324	$2,525	$612	$2,160	$18	$6	$4
5112	Maintenance of Transformer Station Equipment	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5114	Maintenance of Distribution Station Equipment	$35,608		$35,608	$35,608	$0	$35,608	$15,798	$4,429	$15,362	$9	$8	$2
5120	Maintenance of Poles, Towers and Fixtures	$81,251		$81,251	$48,751	$32,500	$81,251	$21,779	$6,177	$20,785	$1	$8	$0
5125	Maintenance of Overhead Conductors and Devices	$280,899		$280,899	$168,539	$112,360	$280,899	$75,279	$21,361	$71,870	$1	$28	$0
5130	Maintenance of Overhead Services	$211,250		$211,250	$0	$211,250	$211,250	$0	$0	$0	$0	$0	$0
5135	Overhead Distribution Lines and Feeders - Right of Way	$176,549		$176,549	$105,929	$70,620	$176,549	$47,319	$13,424	$45,167	$1	$18	$0
5145	Maintenance of Underground Conduit	$11,050		$11,050	$6,630	$4,420	$11,050	$2,998	$851	$2,781	$0	$1	$0
5150	Maintenance of Underground Conductors and Devices	$43,844		$43,844	$26,306	$17,537	$43,844	$11,834	$3,359	$11,109	$0	$4	$0
5155	Maintenance of Underground Services	$33,617		$33,617	$0	$33,617	$33,617	$0	$0	$0	$0	$0	$0
5160	Maintenance of Line Transformers	$201,067		$201,067	$120,640	$80,427	$201,067	$55,860	$15,854	$48,906	$0	$21	$0
5175	Maintenance of Meters	$72,986		$72,986	$0	$72,986	$72,986	$0	$0	$0	$0	$0	$0
5305	Supervision	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5310	Meter Reading Expense	$244,533		$244,533	$0	$244,533	$244,533	$0	$0	$0	$0	$0	$0
5315	Customer Billing	$348,370		$348,370	$0	$348,370	$348,370	$0	$0	$0	$0	$0	$0
5320	Collecting	$114,921		$114,921	$0	$114,921	$114,921	$0	$0	$0	$0	$0	$0
5325	Collecting- Cash Over and Short	$626		$626	$0	$626	$626	$0	$0	$0	$0	$0	$0
5330	Collection Charges	$4,262		$4,262	$0	$4,262	$4,262	$0	$0	$0	$0	$0	$0
5335	Bad Debt Expense	$91,750		$91,750	$0	$91,750	$91,750	$0	$0	$0	$0	$0	$0
5340	Miscellaneous Customer Accounts Expenses	$357,265		$357,265	$0	$357,265	$357,265	$0	$0	$0	$0	$0	$0
5405	Supervision	$0		$0			$0	$0	$0	$0	$0	$0	$0
5410	Community Relations - Sundry	$0		$0			$0	$0	$0	$0	$0	$0	$0
5415	Energy Conservation	$0		$0			$0	$0	$0	$0	$0	$0	$0
5420	Community Safety Program	$0		$0			$0	$0	$0	$0	$0	$0	$0
5425	Miscellaneous Customer Service and Informational Expenses	$0		$0			$0	$0	$0	$0	$0	$0	$0
5505	Supervision	$0		$0			$0	$0	$0	$0	$0	$0	$0
5510	Demonstrating and Selling Expense	$0		$0			$0	$0	$0	$0	$0	$0	$0
5515	Advertising Expense	$0		$0			$0	$0	$0	$0	$0	$0	$0
5520	Miscellaneous Sales Expense	$0		$0			$0	$0	$0	$0	$0	$0	$0
5605	Executive Salaries and Expenses	$1,063,679		$1,063,679			$0	$0	$0	$0	$0	$0	$0
5610	Management Salaries and Expenses	$0		$0			$0	$0	$0	$0	$0	$0	$0
5615	General Administrative Salaries and Expenses	$1,994,625		$1,994,625			$0	$0	$0	$0	$0	$0	$0
5620	Office Supplies and Expenses	$577,668		$577,668			$0	$0	$0	$0	$0	$0	$0
5625	Administrative Expense Transferred Credit	($3,125,910)		($3,125,910)			$0	$0	$0	$0	$0	$0	$0
5630	Outside Services Employed	$232,930		$232,930			$0	$0	$0	$0	$0	$0	$0
5635	Property Insurance	$100,616		$100,616			$0	$0	$0	$0	$0	$0	$0
5640	Injuries and Damages	$125		$125			$0	$0	$0	$0	$0	$0	$0
5645	Employee Pensions and Benefits	$404,529		$404,529			$0	$0	$0	$0	$0	$0	$0
5650	Franchise Requirements	$0		$0			$0	$0	$0	$0	$0	$0	$0
5655	Regulatory Expenses	$88,458		$88,458			$0	$0	$0	$0	$0	$0	$0
5660	General Advertising Expenses	$6,402		$6,402			$0	$0	$0	$0	$0	$0	$0
5665	Miscellaneous General Expenses	$245,884		$245,884			$0	$0	$0	$0	$0	$0	$0
5670	Rent	$350,519		$350,519			$0	$0	$0	$0	$0	$0	$0
5675	Maintenance of General Plant	$376,947		$376,947			$0	$0	$0	$0	$0	$0	$0
5680	Electrical Safety Authority Fees	$0		$0			$0	$0	$0	$0	$0	$0	$0
5685	Independent Market Operator Fees and Penalties	$0		$0			$0	$0	$0	$0	$0	$0	$0
5705	Amortization Expense - Property, Plant, and Equipment	$1,678,905	$0	$1,678,905			$0	$326,349	$92,797	$307,750	($30)	$114	($6)
5710	Amortization of Limited Term Electric Plant	$0	$0	$0			$0	$0	$0	$0	$0	$0	$0
5715	Amortization of Intangibles and Other Electric Plant	$5,746	$0	$5,746			$0	$0	$0	$0	$0	$0	$0
5720	Amortization of Electric Plant Acquisition Adjustments	$0	$0	$0			$0	$0	$0	$0	$0	$0	$0
5730	Amortization of Unrecovered Plant and Regulatory Study Costs	$0		$0									
5735	Amortization of Deferred Development Costs	$0		$0									
5740	Amortization of Deferred Charges	$0		$0									
6005	Interest on Long Term Debt	$1,177,975		$1,177,975				$0	$0	$0	$0	$0	$0
6105	Taxes Other Than Income Taxes	$71,404		$71,404	$0	$0	$0	$0	$0	$0	$0	$0	$0
6110	Income Taxes	$163,414		$163,414			$0	$0	$0	$0	$0	$0	$0
6205	Donations	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6210	Life Insurance	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6215	Penalties	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6225	Other Deductions	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
		$51,704,560	($0)	$51,704,560	$24,509,394	$20,604,827	$45,114,221	$7,173,174	$1,975,751	$6,602,329	$10,351	$5,422	$2,050
							O5 Summary	O4 Summary					
					$8,740,317	$6,133,113	$51,704,561	$51,704,561					
							($1)						
				$0			$51,704,560						

5085	$185,780	$93,552	$10,680	$2,687	$13,641	$2,647	$646	$123,853	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5090	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5095	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5096	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,403	$258	$384	$61	$12	$17	$2,135	$0
5105	$25,348	$12,764	$1,457	$367	$1,861	$361	$88	$16,899	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5110	$5,324	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5112	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5114	$35,608	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5120	$48,751	$25,346	$2,323	$244	$3,686	$717	$175	$32,500	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5125	$168,539	$87,624	$8,032	$843	$12,776	$2,479	$605	$112,360	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5130	$0	$145,439	$26,664	$12,821	$21,206	$4,115	$1,005	$211,250	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5135	$105,929	$55,073	$5,048	$530	$8,030	$1,558	$381	$70,620	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5145	$6,630	$3,448	$316	$32	$503	$98	$24	$4,420	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5150	$26,306	$13,678	$1,254	$129	$1,994	$387	$95	$17,537	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5155	$0	$23,144	$4,243	$2,040	$3,375	$655	$160	$33,617	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5160	$120,640	$62,760	$5,753	$553	$9,151	$1,776	$434	$80,427	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5175	$0	$44,839	$9,374	$18,773	$0	$0	$0	$72,986	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5305	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5310	$0	$191,885	$38,558	$14,090	$0	$0	$0	$244,533	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5315	$0	$270,240	$49,544	$18,617	$306	$127	$9,336	$348,370	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5320	$0	$89,148	$16,344	$6,207	$101	$42	$3,080	$114,921	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5325	$0	$485	$89	$34	$1	$0	$17	$626	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5330	$0	$3,306	$606	$230	$4	$2	$114	$4,262	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5335	$0	$88,525	$3,225	$0	$0	$0	$0	$91,750	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5340	$0	$277,140	$50,809	$19,297	$314	$130	$9,574	$357,265	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5405	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5410	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5415	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5420	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5425	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5505	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5510	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5515	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5520	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5605	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$698,971	$128,634	$191,365	$30,281	$5,994	$8,433	$1,063,679	$0
5610	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5615	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,310,721	$241,216	$358,850	$56,784	$11,240	$15,813	$1,994,625	$0
5620	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$379,601	$69,859	$103,927	$16,445	$3,255	$4,580	$577,668	$0
5625	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($2,054,118)	($378,026)	($562,378)	($88,990)	($17,616)	($24,781)	($3,125,910)	$0
5630	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$153,064	$28,169	$41,906	$6,631	$1,313	$1,847	$232,930	$0
5635	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$58,424	$11,252	$25,322	$4,511	$887	$219	$100,616	$0
5640	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$82	$15	$22	$4	$1	$1	$125	$0
5645	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$265,827	$48,921	$72,778	$11,516	$2,280	$3,207	$404,529	$0
5650	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5655	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$58,128	$10,697	$15,914	$2,518	$498	$701	$88,458	$0
5660	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,207	$774	$1,152	$182	$36	$51	$6,402	$0
5665	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$161,577	$29,736	$44,237	$7,000	$1,386	$1,949	$245,884	$0
5670	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$230,335	$42,389	$63,061	$9,979	$1,975	$2,779	$350,519	$0
5675	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$247,702	$45,585	$67,816	$10,731	$2,124	$2,988	$376,947	$0
5680	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5685	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5705	$726,974	$393,857	$42,499	$25,980	$49,511	$9,607	$2,346	$523,900								$248,542	$47,868	$107,722	$19,192	$3,775	$933	$428,031	$0
5710	$0	$0	$0	$0	$0	$0	$0	$0								$0	$0	$0	$0	$0	$0	$0	$0
5715	$0	$0	$0	$0	$0	$0	$0	$0								$3,336	$643	$1,446	$258	$51	$13	$5,746	$0
5720	$0	$0	$0	$0	$0	$0	$0	$0								$0	$0	$0	$0	$0	$0	$0	$0
5730									$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5735									$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5740									$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6005	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$683,984	$132,385	$295,753	$52,877	$10,402	$2,575	$1,177,975	$0
6105	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$41,460	$8,025	$17,927	$3,265	$630	$156	$71,404	$0
6110	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$94,885	$18,365	$41,028	$7,335	$1,443	$357	$163,414	$0
6205	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6210	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6215	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6225	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$15,769,077	$10,637,380	$1,446,312	$770,355	$1,285,155	$249,527	$82,984	$14,471,714	($6,044,171)	($1,776,490)	($3,789,680)	($137,932)	($40,022)	($35,271)	($11,823,567)	$13,720,242	$4,647,013	$14,316,972	$435,911	$112,617	$54,582	$33,287,336	($1)

Grouping by Allocator	Adjusted TB	Demand	Customer	Total	Residential	GS <50	GS>50-Regular	GS> 50-TOU	GS >50-Intermediate	Unmetered Scattered Load	Embedded Distributor	Back-up/Standby Power	GS <50	GS>50-Regular	GS> 50-TOU	GS >50-Intermediate	Unmetered Scattered Load	Embedded Distributor	Back-up/Standby Power	GS <50	GS>50-Regular	GS> 50-TOU	GS >50-Intermediate	Unmetered Scattered Load	Embedded Distributor	Back-up/Standby Power	GS <50	GS>50-Regular	GS> 50-TOU	GS >50-Intermediate	Unmetered Scattered Load	Embedded Distributor	Back-up/Standby Power
1808	99,361.60	99,361.60	-	99,361.60	47,129.16	11,412.86	40,307.57	-	-	66.95	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1815	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1820	91,159.91	91,159.91	-	91,159.91	40,444.23	11,338.13	39,327.01	-	-	4.79	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1830	81,251.04	48,750.62	32,500.42	81,251.04	21,779.10	6,176.84	20,785.42	-	-	0.15	-	-	2,323.35	243.73	-	-	175.12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1835	280,899.01	168,539.41	112,359.60	280,899.01	75,278.91	21,361.37	71,869.94	-	-	0.13	-	-	8,032.23	842.60	-	-	605.42	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1840	11,050.24	6,630.14	4,420.10	11,050.24	2,997.55	850.75	2,780.72	-	-	-	-	-	316.04	32.23	-	-	23.82	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1845	43,843.69	26,306.21	17,537.48	43,843.69	11,833.90	3,358.63	11,109.25	-	-	-	-	-	1,253.85	129.37	-	-	94.51	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1850	268,138.98	160,883.39	107,255.59	268,138.98	74,493.44	21,142.31	65,219.71	-	-	-	-	-	7,672.15	737.80	-	-	578.28	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1855	244,866.40	-	244,866.40	244,866.40	-	-	-	-	-	-	-	-	30,907.03	14,861.08	-	-	1,164.79	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1860	72,985.81	-	72,985.81	72,985.81	-	-	-	-	-	-	-	-	9,374.05	18,773.19	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1815-1855	511,022.34	306,613.40	204,408.94	511,022.34	138,004.45	39,090.12	129,447.58	-	-	2.64	-	-	17,626.94	4,435.14	-	-	1,066.79	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1830 & 1835	246,809.19	148,085.51	98,723.68	246,809.19	66,150.38	18,765.63	63,142.50	-	-	0.30	-	-	7,057.44	740.35	-	-	531.94	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1840 & 1845	86,524.43	51,914.66	34,609.77	86,524.43	23,367.31	6,631.98	21,906.62	-	-	-	-	-	2,474.47	254.98	-	-	186.51	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BCP	32,188.00	32,188.00	-	32,188.00	15,267.40	3,697.17	13,057.56	-	-	21.69	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BDHA	91,750.45	-	91,750.45	91,750.45	-	-	-	-	-	-	-	-	3,225.23	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Break Out	(17,232,802.06)	-	-	-	(3,932,454.86)	(1,110,537.90)	(3,694,453.04)	-	-	(189.25)	-	-	(504,158.81)	(333,295.39)	-	-	(26,836.56)	-	-	-	-	-	-	-	-	-	(263,856.48)	(593,778.30)	-	-	(5,141.10)	-	-
CCA	11,361.30	-	11,361.30	11,361.30	-	-	-	-	-	-	-	-	811.97	88.11	-	-	61.20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CDMPP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CEN	4,710,074.23	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	687,316.81	2,269,521.15	-	-	4,804.62	-	-
CEN EWMP	21,789,738.19	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3,179,664.00	10,499,255.26	-	-	22,227.15	-	-
CREV	(9,810,770.00)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,533,242.66)	(3,366,004.00)	-	-	(19,846.34)	-	-	-	-	-	-	-	-	-
CWCS	4,293,321.49	-	4,293,321.49	4,293,321.49	-	-	-	-	-	-	-	-	541,902.88	260,564.09	-	-	20,422.59	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CWMC	2,557,710.97	-	2,557,710.97	2,557,710.97	-	-	-	-	-	-	-	-	328,503.89	657,886.60	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CWMR	244,533.07	-	244,533.07	244,533.07	-	-	-	-	-	-	-	-	38,558.05	14,089.79	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CWNB	376,643.83	-	825,444.22	825,444.22	-	-	-	-	-	-	-	-	117,392.65	44,584.80	-	-	22,120.77	-	-	(63,827.29)	(24,241.10)	-	-	(12,027.23)	-	-	-	-	-	-	-	-	-
DCP	3,179,349.61	3,179,349.61	-	3,179,349.61	1,508,028.00	365,186.02	1,289,752.19	-	-	2,142.14	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LPHA	(71,821.30)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(11,723.87)	(24,796.04)	-	-	(135.75)	-	-	-	-	-	-	-	-	-
LTNCP	7,102,674.33	4,261,604.60	2,841,069.73	7,102,674.33	1,973,240.35	560,034.08	1,727,590.60	-	-	-	-	-	203,225.95	19,543.50	-	-	15,317.88	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NFA	(79,381.81)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(167,695.95)	(374,639.19)	-	-	(3,261.63)	-	-	158,774.74	354,708.86	-	-	3,088.12	-	-
NFA ECC	5,516,111.91	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	616,885.54	1,388,229.14	-	-	12,019.67	-	-
O&M	2,217,990.01	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	268,228.57	399,035.66	-	-	17,583.55	-	-
PNCP	18,493,214.60	12,181,150.88	6,312,063.72	18,493,214.60	5,372,716.64	1,524,854.49	5,281,566.04	-	-	-	-	-	451,133.89	48,660.32	-	-	34,003.59	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SNCP	6,244,760.20	3,746,856.12	2,497,904.08	6,244,760.20	1,734,897.62	492,388.97	1,518,919.29	-	-	-	-	-	178,678.80	17,182.89	-	-	13,467.67	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TCP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**51,704,560**	**24,509,394**	**20,604,827**	**45,114,221**	**7,173,174**	**1,975,751**	**6,602,329**	-	-	**2,050**	-	-	**1,446,312**	**770,355**	-	-	**82,984**	-	-	**-$ 1,776,490**	**-$ 3,789,680**	-	-	**-$ 35,271**	-	-	**4,647,013**	**14,316,972**	-	-	**54,582**	-	-

2006 COST ALLOCATION INFORMATION FILING

Canadian Niagara Power Inc - Fort Erie & EOP

Monday, July 14, 2008

Sheet O6 Composite Allocator Detail Worksheet - Second Run

Details:
Output Sheet Details How Various Composite Allocators are Derived

Demand Allocators can be found in columns C to AG
Customer Allocators can be found in columns AJ to BN

		Demand Allocators							Customer Allocators							
			1	2	3	7	8	9		1	2	3	7	8	9	
		Demand Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Customer Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Total
Composite allocators																
Rate Base																
1565	Conservation and Demand Management	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805-1	Land Station >50 kV		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805-2	Land Station <50 kV		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805	Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806-1	Land Rights Station >50 kV		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806-2	Land Rights Station <50 kV		$49,395	$11,962	$42,245	$354	$112	$70	$0	$0	$0	$0	$0	$0	$0	$0
1806	Total	$104,138	$49,395	$11,962	$42,245	$354	$112	$70	$0	$0	$0	$0	$0	$0	$0	$104,138
1808-1	Buildings and Fixtures > 50 kV		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-2	Buildings and Fixtures < 50 KV		$1,349,734	$326,853	$1,154,370	$9,683	$3,063	$1,917	$0	$0	$0	$0	$0	$0	$0	$0
1808	Total	$2,845,621	$1,349,734	$326,853	$1,154,370	$9,683	$3,063	$1,917	$0	$0	$0	$0	$0	$0	$0	$2,845,621
1810-1	Leasehold Improvements >50 kV		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810-2	Leasehold Improvements <50 kV		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810	Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$229,590	$108,899	$26,371	$93,137	$781	$247	$155	$0	$0	$0	$0	$0	$0	$0	$229,590
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$2,713,055	$1,196,642	$339,624	$1,176,340	$0	$449	$0	$0	$0	$0	$0	$0	$0	$0	$2,713,055
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820	Total	$2,942,645	$1,305,541	$365,995	$1,269,477	$781	$696	$155	$0	$0	$0	$0	$0	$0	$0	$2,942,645
1815 & 1820	Total	$2,942,645	$1,305,541	$365,995	$1,269,477	$781	$696	$155	$0	$0	$0	$0	$0	$0	$0	$2,942,645
1825-1	Storage Battery Equipment > 50 kV		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825-2	Storage Battery Equipment <50 kV		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825	Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery		$12,584	$3,047	$10,762	$90	$29	$18	$0	$0	$0	$0	$0	$0	$0	$0
1830-4	Poles, Towers and Fixtures - Primary		$1,913,180	$542,988	$1,880,722	$0	$717	$0	$2,891,739	$2,254,651	$206,677	$22,293	$328,750	$63,789	$15,578	$2,891,739
1830-5	Poles, Towers and Fixtures - Secondary		$679,439	$192,835	$594,855	$0	$255	$0	$978,256	$763,372	$69,976	$6,729	$111,307	$21,598	$5,274	$978,256
1830	Total	$5,831,522	$2,605,203	$738,870	$2,486,340	$90	$1,000	$18	$3,869,995	$3,018,023	$276,654	$29,022	$440,057	$85,387	$20,852	$9,701,516
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery		$2,684	$650	$2,295	$19	$6	$4	$0	$0	$0	$0	$0	$0	$0	$0
1835-4	Overhead Conductors and Devices - Primary		$1,600,890	$454,356	$1,573,730	$0	$600	$0	$2,419,718	$1,886,622	$172,941	$18,654	$275,088	$53,377	$13,035	$2,419,718
1835-5	Overhead Conductors and Devices - Secondary		$569,006	$161,492	$498,170	$0	$213	$0	$819,254	$639,296	$58,602	$5,636	$93,216	$18,087	$4,417	$819,254
1835	Total	$4,864,115	$2,172,580	$616,498	$2,074,196	$19	$819	$4	$3,238,972	$2,525,918	$231,544	$24,289	$368,304	$71,464	$17,452	$8,103,087
1830 & 1835	Total	$10,695,637	$4,777,783	$1,355,368	$4,560,536	$110	$1,820	$22	$7,108,966	$5,543,941	$508,197	$53,311	$808,361	$156,851	$38,305	$17,804,603
1840-3	Underground Conduit - Bulk Delivery		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary		$63,994	$18,162	$62,908	$0	$24	$0	$96,725	$75,415	$6,913	$746	$10,996	$2,134	$521	$96,725
1840-5	Underground Conduit - Secondary		$67,938	$19,282	$59,480	$0	$25	$0	$97,817	$76,330	$6,997	$673	$11,130	$2,160	$527	$97,817
1840	Total	$291,813	$131,932	$37,444	$122,388	$0	$49	$0	$194,542	$151,746	$13,910	$1,419	$22,126	$4,293	$1,048	$486,355
1845-3	Underground Conductors and Devices Bulk Delivery		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-4	Underground Conductors and Devices Primary		$598,010	$169,724	$587,865	$0	$224	$0	$903,882	$704,745	$64,602	$6,968	$102,759	$19,939	$4,869	$903,882
1845-5	Underground Conductors and Devices Secondary		$418,515	$118,781	$366,414	$0	$157	$0	$602,577	$470,215	$43,103	$4,145	$68,562	$13,303	$3,249	$602,577
1845	Total	$2,259,689	$1,016,525	$288,505	$954,279	$0	$381	$0	$1,506,460	$1,174,960	$107,705	$11,113	$171,321	$33,242	$8,118	$3,766,149
1840 & 1845	Total	$2,551,503	$1,148,457	$325,949	$1,076,667	$0	$430	$0	$1,701,002	$1,326,706	$121,615	$12,532	$193,447	$37,536	$9,167	$4,252,504
1850	Line Transformers	$4,261,605	$1,973,240	$560,034	$1,727,591	$0	$740	$0	$2,841,070	$2,216,998	$203,226	$19,543	$323,260	$62,724	$15,318	$7,102,674
1815- 1850	Total	$20,451,390	$9,205,021	$2,607,346	$8,634,270	$891	$3,685	$176	$11,651,038	$9,087,645	$833,039	$85,387	$1,325,067	$257,111	$62,789	$32,102,427
1855	Services	$0	$0	$0	$0	$0	$0	$0	$4,293,321	$2,955,818	$541,903	$260,564	$430,987	$83,627	$20,423	$4,293,321
1815- 1855	Total	$20,451,390	$9,205,021	$2,607,346	$8,634,270	$891	$3,685	$176	$15,944,359	$12,043,463	$1,374,942	$345,951	$1,756,054	$340,738	$83,212	$36,395,749

	A	B	C	D	E	F	J	K	L	X	Y	Z	AA	AE	AF	AG	AS
90	1860	Meters	$0	$0	$0	$0	$0	$0	$0	$2,402,778	$1,476,138	$308,605	$618,035	$0	$0	$0	$2,402,778
91																	
92	1815-1860	Total	$20,451,390	$9,205,021	$2,607,346	$8,634,270	$891	$3,685	$176	$18,347,137	$13,519,601	$1,683,546	$963,986	$1,756,054	$340,738	$83,212	$38,798,527
93																	
94	1565-1860	Total	$23,401,149	$10,604,150	$2,946,161	$9,830,886	$10,928	$6,861	$2,164	$18,347,137	$13,519,601	$1,683,546	$963,986	$1,756,054	$340,738	$83,212	$41,748,286
95																	
96		Total Demand And Customer	$41,748,286	$24,123,751	$4,629,707	$10,794,872	$1,766,983	$347,598	$85,376								
97		Accum Depreciation - NFA	($16,124,304)	($9,245,347)	($1,749,992)	($4,361,478)	($616,781)	($121,339)	($29,366)								
98		Accum Depreciation - NFA ECC	($13,927,124)	($7,969,043)	($1,518,372)	($3,793,174)	($519,532)	($102,250)	($24,753)								
99	NFA	Net Fixed Assets	$25,623,982	$14,878,403	$2,879,715	$6,433,393	$1,150,202	$226,259	$56,010								
100	NFA ECC	Net Fixed Assets Excluding Capital Contribution	$27,821,162	$16,154,707	$3,111,335	$7,001,698	$1,247,451	$245,348	$60,623								
101																	
102																	
103	**Operating and Maintenance**			Allocate all the costs to the O and M expenses before using it as a composite allocator.													
104																	
105	**Acccounts**																
106	5005	Operation Supervision and Engineering	$8,429	$3,794	$1,075	$3,558	$0	$2	$0	$4,851	$4,244	$485	$122	$619	$120	$29	
107	5010	Load Dispatching	$87,057	$39,184	$11,099	$36,754	$4	$16	$1	$50,103	$43,839	$5,005	$1,259	$6,392	$1,240	$303	
108	5012	Station Buildings and Fixtures Expense	$94,038	$44,604	$10,801	$38,148	$320	$101	$63	$0	$0	$0	$0	$0	$0	$0	
109	5014	Transformer Station Equipment - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
110	5015	Transformer Station Equipment - Operation Supplies and Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
111	5016	Distribution Station Equipment - Operation Labour	$51,573	$22,881	$6,414	$22,249	$14	$12	$3	$0	$0	$0	$0	$0	$0	$0	
112	5017	Distribution Station Equipment - Operation Supplies and Expenses	$3,978	$1,765	$495	$1,716	$1	$1	$0	$0	$0	$0	$0	$0	$0	$0	
113	5020	Overhead Distribution Lines and Feeders - Operation Labour	$28,815	$12,872	$3,652	$12,287	$0	$5	$0	$16,498	$14,981	$1,373	$144	$2,184	$424	$104	
114	5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$13,341	$5,959	$1,691	$5,688	$0	$2	$0	$7,638	$6,936	$636	$67	$1,011	$196	$48	
115	5030	Overhead Subtransmission Feeders - Operation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
116	5035	Overhead Distribution Transformers- Operation	$31,136	$14,417	$4,092	$12,622	$0	$5	$0	$17,826	$16,198	$1,485	$143	$2,362	$458	$112	
117	5040	Underground Distribution Lines and Feeders - Operation Labour	$51,343	$23,110	$6,559	$21,666	$0	$9	$0	$29,397	$26,697	$2,447	$252	$3,893	$755	$184	
118	5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$571	$257	$73	$241	$0	$0	$0	$327	$297	$27	$3	$43	$8	$2	
119	5050	Underground Subtransmission Feeders - Operation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
120	5055	Underground Distribution Transformers - Operation	$9,107	$4,217	$1,197	$3,692	$0	$2	$0	$5,214	$4,738	$434	$42	$691	$134	$33	
121	5065	Meter Expense	$0	$0	$0	$0	$0	$0	$0	$154,933	$95,183	$19,899	$39,851	$0	$0	$0	
122	5070	Customer Premises - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$1,679	$1,524	$140	$15	$222	$43	$11	
123	5075	Customer Premises - Materials and Expenses	$0	$0	$0	$0	$0	$0	$0	$8,079	$7,334	$672	$73	$1,069	$207	$51	
124	5085	Miscellaneous Distribution Expense	$185,780	$83,618	$23,685	$78,433	$8	$33	$2	$106,919	$93,552	$10,680	$2,687	$13,641	$2,647	$646	
125	5090	Underground Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
126	5095	Overhead Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
127	5096	Other Rent	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
128	5105	Maintenance Supervision and Engineering	$25,348	$11,409	$3,232	$10,702	$1	$5	$0	$14,588	$12,764	$1,457	$367	$1,861	$361	$88	
129	5110	Maintenance of Buildings and Fixtures - Distribution Stations	$5,324	$2,525	$612	$2,160	$18	$6	$4	$0	$0	$0	$0	$0	$0	$0	
130	5112	Maintenance of Transformer Station Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
131	5114	Maintenance of Distribution Station Equipment	$35,608	$15,798	$4,429	$15,362	$9	$8	$2	$0	$0	$0	$0	$0	$0	$0	
132	5120	Maintenance of Poles, Towers and Fixtures	$48,751	$21,779	$6,177	$20,785	$1	$8	$0	$27,913	$25,346	$2,323	$244	$3,696	$717	$175	
133	5125	Maintenance of Overhead Conductors and Devices	$168,539	$75,279	$21,361	$71,870	$1	$28	$0	$96,499	$87,624	$8,032	$843	$12,776	$2,479	$605	
134	5130	Maintenance of Overhead Services	$0	$0	$0	$0	$0	$0	$0	$184,924	$145,439	$26,664	$12,821	$21,206	$4,115	$1,005	
135	5135	Overhead Distribution Lines and Feeders - Right of Way	$105,929	$47,319	$13,424	$45,167	$1	$18	$0	$60,651	$55,073	$5,048	$530	$8,030	$1,558	$381	
136	5145	Maintenance of Underground Conduit	$6,630	$2,998	$851	$2,781	$0	$1	$0	$3,796	$3,448	$316	$32	$503	$98	$24	
137	5150	Maintenance of Underground Conductors and Devices	$26,306	$11,834	$3,359	$11,109	$0	$4	$0	$15,062	$13,678	$1,254	$129	$1,994	$387	$95	
138	5155	Maintenance of Underground Services	$0	$0	$0	$0	$0	$0	$0	$29,427	$23,144	$4,243	$2,040	$3,375	$655	$160	
139	5160	Maintenance of Line Transformers	$120,640	$55,860	$15,854	$48,906	$0	$21	$0	$69,067	$62,760	$5,753	$553	$9,151	$1,776	$434	
140	5175	Maintenance of Meters	$0	$0	$0	$0	$0	$0	$0	$72,986	$44,839	$9,374	$18,773	$0	$0	$0	
141	5305	Supervision	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
142	5310	Meter Reading Expense	$0	$0	$0	$0	$0	$0	$0	$244,533	$191,885	$38,558	$14,090	$0	$0	$0	
143	5315	Customer Billing	$0	$0	$0	$0	$0	$0	$0	$338,601	$270,240	$49,544	$18,817	$306	$127	$9,336	
144	5320	Collecting	$0	$0	$0	$0	$0	$0	$0	$111,699	$89,148	$16,344	$6,207	$101	$42	$3,080	
145	5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	$608	$485	$89	$34	$1	$0	$17	
146	5330	Collection Charges	$0	$0	$0	$0	$0	$0	$0	$4,142	$3,306	$606	$230	$4	$2	$114	
147	5335	Bad Debt Expense	$0	$0	$0	$0	$0	$0	$0	$91,750	$88,525	$3,225	$0	$0	$0	$0	
148	5340	Miscellaneous Customer Accounts Expenses	$0	$0	$0	$0	$0	$0	$0	$347,247	$277,140	$50,809	$19,297	$314	$130	$9,574	
149																	
150	O&M DC	Total	$1,108,245	$501,478	$140,129	$465,896	$379	$288	$75	$2,116,955	$1,710,366	$266,925	$139,665	$95,445	$18,680	$26,609	
151																	
152	O&M	Total Demand and Customer	$3,365,935	$2,211,845	$407,053	$605,561	$95,823	$18,968	$26,684								
153																	
154																	
155	**Accounts**																
156	4705	Power Purchased	$18,583,495	$6,738,782	$2,711,793	$8,954,346	$117,679	$41,939	$18,957	$18,583,495							
157	4708	Charges-WMS	$2,242,395	$813,141	$327,221	$1,080,484	$14,200	$5,061	$2,287	$2,242,395							
158	4710	Cost of Power Adjustments	$963,849	$349,513	$140,650	$464,425	$6,104	$2,175	$983	$963,849							
159	4712	Charges-One-Time	$0	$0	$0	$0	$0	$0	$0	$0							
160	4714	Charges-NW	$2,481,440	$899,824	$362,104	$1,195,667	$15,714	$5,600	$2,531	$2,481,440							
161	4716	Charges-CN	$2,228,634	$808,152	$325,213	$1,073,854	$14,113	$5,030	$2,273	$2,228,634							

	A	B	C	D	E	F	J	K	L	X	Y	Z	AA	AE	AF	AG	AS
162	4730	Rural Rate Assistance Expense	$0	$0	$0	$0	$0	$0	$0	$0							
163	5685	Independent Market Operator Fees and Penalties	$0	$0	$0	$0	$0	$0	$0	$0							
164																	
165	COP	Cost of Power	$26,499,812	$9,609,412	$3,866,981	$12,768,776	$167,808	$59,804	$27,032	$26,499,812							
166																	
167	**Acccounts**																
168	5005	Operation Supervision and Engineering	$14,048	$8,038	$1,559	$3,680	$619	$122	$29	$14,048							
169	5010	Load Dispatching	$145,095	$83,022	$16,104	$38,013	$6,396	$1,256	$304	$145,095							
170	5012	Station Buildings and Fixtures Expense	$94,038	$44,604	$10,801	$38,148	$320	$101	$63	$94,038							
171	5014	Transformer Station Equipment - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0							
172	5015	Transformer Station Equipment - Operation Supplies and Expenses	$0	$0	$0	$0	$0	$0	$0	$0							
173	5016	Distribution Station Equipment - Operation Labour	$51,573	$22,881	$6,414	$22,249	$14	$12	$3	$51,573							
174	5017	Distribution Station Equipment - Operation Supplies and Expenses	$3,978	$1,765	$495	$1,716	$1	$1	$0	$3,978							
175	5020	Overhead Distribution Lines and Feeders - Operation Labour	$48,025	$27,853	$5,025	$12,431	$2,185	$429	$104	$48,025							
176	5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$22,235	$12,895	$2,326	$5,755	$1,011	$199	$48	$22,235							
177	5030	Overhead Subtransmission Feeders - Operation	$0	$0	$0	$0	$0	$0	$0	$0							
178	5035	Overhead Distribution Transformers- Operation	$51,894	$30,615	$5,577	$12,765	$2,362	$464	$112	$51,894							
179	5040	Underground Distribution Lines and Feeders - Operation Labour	$85,572	$49,807	$9,006	$21,918	$3,893	$764	$184	$85,572							
180	5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$952	$554	$100	$244	$43	$8	$2	$952							
181	5050	Underground Subtransmission Feeders - Operation	$0	$0	$0	$0	$0	$0	$0	$0							
182	5055	Underground Distribution Transformers - Operation	$15,178	$8,954	$1,631	$3,734	$691	$136	$33	$15,178							
183	5065	Meter Expense	$154,933	$95,183	$19,899	$39,851	$0	$0	$0	$154,933							
184	5070	Customer Premises - Operation Labour	$1,955	$1,524	$140	$15	$222	$43	$11	$1,955							
185	5075	Customer Premises - Materials and Expenses	$9,406	$7,334	$672	$73	$1,069	$207	$51	$9,406							
186	5085	Miscellaneous Distribution Expense	$309,633	$177,170	$34,365	$81,121	$13,649	$2,680	$648	$309,633							
187	5090	Underground Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0							
188	5095	Overhead Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0							
189	5096	Other Rent	$2,135	$1,403	$258	$384	$61	$12	$17	$2,135							
190	5105	Maintenance Supervision and Engineering	$42,247	$24,173	$4,689	$11,068	$1,862	$366	$88	$42,247							
191	5110	Maintenance of Buildings and Fixtures - Distribution Stations	$5,324	$2,525	$612	$2,160	$18	$6	$4	$5,324							
192	5112	Maintenance of Transformer Station Equipment	$0	$0	$0	$0	$0	$0	$0	$0							
193	5114	Maintenance of Distribution Station Equipment	$35,608	$15,798	$4,429	$15,362	$9	$8	$2	$35,608							
194	5120	Maintenance of Poles, Towers and Fixtures	$81,251	$47,125	$8,500	$21,029	$3,696	$725	$175	$81,251							
195	5125	Maintenance of Overhead Conductors and Devices	$280,899	$162,903	$29,394	$72,713	$12,777	$2,507	$606	$280,899							
196	5130	Maintenance of Overhead Services	$211,250	$145,439	$26,664	$12,821	$21,206	$4,115	$1,005	$211,250							
197	5135	Overhead Distribution Lines and Feeders - Right of Way	$176,549	$102,392	$18,472	$45,697	$8,031	$1,576	$381	$176,549							
198	5145	Maintenance of Underground Conduit	$11,050	$6,445	$1,167	$2,813	$503	$99	$24	$11,050							
199	5150	Maintenance of Underground Conductors and Devices	$43,844	$25,512	$4,612	$11,239	$1,994	$391	$95	$43,844							
200	5155	Maintenance of Underground Services	$33,617	$23,144	$4,243	$2,040	$3,375	$655	$160	$33,617							
201	5160	Maintenance of Line Transformers	$201,067	$118,620	$21,607	$49,459	$9,151	$1,797	$434	$201,067							
202	5175	Maintenance of Meters	$72,986	$44,839	$9,374	$18,773	$0	$0	$0	$72,986							
203	5305	Supervision	$0	$0	$0	$0	$0	$0	$0	$0							
204	5310	Meter Reading Expense	$244,533	$191,885	$38,558	$14,090	$0	$0	$0	$244,533							
205	5315	Customer Billing	$348,370	$270,240	$49,544	$18,817	$306	$127	$9,336	$348,370							
206	5320	Collecting	$114,921	$89,148	$16,344	$6,207	$101	$42	$3,080	$114,921							
207	5325	Collecting- Cash Over and Short	$626	$485	$89	$34	$1	$0	$17	$626							
208	5330	Collection Charges	$4,262	$3,306	$606	$230	$4	$2	$114	$4,262							
209	5335	Bad Debt Expense	$91,750	$88,525	$3,225	$0	$0	$0	$0	$91,750							
210	5340	Miscellaneous Customer Accounts Expenses	$357,265	$277,140	$50,809	$19,297	$314	$130	$9,574	$357,265							
211	5405	Supervision	$0	$0	$0	$0	$0	$0	$0	$0							
212	5410	Community Relations - Sundry	$0	$0	$0	$0	$0	$0	$0	$0							
213	5415	Energy Conservation	$0	$0	$0	$0	$0	$0	$0	$0							
214	5420	Community Safety Program	$0	$0	$0	$0	$0	$0	$0	$0							
215	5425	Miscellaneous Customer Service and Informational Expenses	$0	$0	$0	$0	$0	$0	$0	$0							
216	5505	Supervision	$0	$0	$0	$0	$0	$0	$0	$0							
217	5510	Demonstrating and Selling Expense	$0	$0	$0	$0	$0	$0	$0	$0							
218	5515	Advertising Expense	$0	$0	$0	$0	$0	$0	$0	$0							
219	5520	Miscellaneous Sales Expense	$0	$0	$0	$0	$0	$0	$0	$0							
220	5605	Executive Salaries and Expenses	$1,063,679	$698,971	$128,634	$191,365	$30,281	$5,994	$8,433	$1,063,679							
221	5610	Management Salaries and Expenses	$0	$0	$0	$0	$0	$0	$0	$0							
222	5615	General Administrative Salaries and Expenses	$1,994,625	$1,310,721	$241,216	$358,850	$56,784	$11,240	$15,813	$1,994,625							
223	5620	Office Supplies and Expenses	$577,668	$379,601	$69,859	$103,927	$16,445	$3,255	$4,580	$577,668							
224	5625	Administrative Expense Transferred Credit	($3,125,910)	($2,054,118)	($378,026)	($562,378)	($88,990)	($17,616)	($24,781)	($3,125,910)							
225	5630	Outside Services Employed	$232,930	$153,064	$28,169	$41,906	$6,631	$1,313	$1,847	$232,930							
226	5635	Property Insurance	$100,616	$58,424	$11,252	$25,322	$4,511	$887	$219	$100,616							
227	5640	Injuries and Damages	$125	$82	$15	$22	$4	$1	$1	$125							
228	5645	Employee Pensions and Benefits	$404,529	$265,827	$48,921	$72,778	$11,516	$2,280	$3,207	$404,529							
229	5650	Franchise Requirements	$0	$0	$0	$0	$0	$0	$0	$0							
230	5655	Regulatory Expenses	$88,458	$58,128	$10,697	$15,914	$2,518	$498	$701	$88,458							
231	5660	General Advertising Expenses	$6,402	$4,207	$774	$1,152	$182	$36	$51	$6,402							
232	5665	Miscellaneous General Expenses	$245,884	$161,577	$29,736	$44,237	$7,000	$1,386	$1,949	$245,884							

A	B	C	D	E	F	J	K	L	X
5670	Rent	$350,519	$230,335	$42,389	$63,061	$9,979	$1,975	$2,779	$350,519
5675	Maintenance of General Plant	$376,947	$247,702	$45,585	$67,816	$10,731	$2,124	$2,988	$376,947
5680	Electrical Safety Authority Fees	$0	$0	$0	$0	$0	$0	$0	$0
6105	Taxes Other Than Income Taxes	$71,404	$41,460	$8,025	$17,927	$3,205	$630	$156	$71,404
6205	Donations	$0	$0	$0	$0	$0	$0	$0	$0
6210	Life Insurance	$0	$0	$0	$0	$0	$0	$0	$0
6215	Penalties	$0	$0	$0	$0	$0	$0	$0	$0
6225	Other Deductions	$0	$0	$0	$0	$0	$0	$0	$0
	OM&A Expenses	**$5,755,945**	**$3,769,229**	**$694,559**	**$1,047,846**	**$166,683**	**$32,985**	**$44,643**	**$5,755,945**

Grouping of Operating and Maintenance Distribution Costs (lines 106 - 148)	Demand Allocators								Customer Allocators						
	Demand Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Customer Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Total
1808	99,362	47,129	11,413	40,308	338	107	67	-	-	-	-	-	-	-	-
1815	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1820	91,160	40,444	11,338	39,327	24	22	5	-	-	-	-	-	-	-	-
1830	48,751	21,779	6,177	20,785	1	8	0	27,913	25,346	2,323	244	3,696	717	175	-
1835	168,539	75,279	21,361	71,870	1	28	0	96,499	87,624	8,032	843	12,776	2,479	605	-
1840	6,630	2,998	851	2,781	-	1	-	3,796	3,448	316	32	503	98	24	-
1845	26,306	11,834	3,359	11,109	-	4	-	15,062	13,678	1,254	129	1,994	387	95	-
1850	160,883	74,493	21,142	65,220	-	28	-	92,106	83,696	7,672	738	12,204	2,368	578	-
1855	-	-	-	-	-	-	-	214,351	168,583	30,907	14,861	24,581	4,770	1,165	-
1860	-	-	-	-	-	-	-	72,986	44,839	9,374	18,773	-	-	-	-
1815-1855	306,613	138,004	39,090	129,448	13	55	3	176,461	154,399	17,627	4,435	22,513	4,368	1,067	-
1830 & 1835	148,086	66,150	18,766	63,142	2	25	0	84,788	76,990	7,057	740	11,226	2,178	532	-
1840 & 1845	51,915	23,367	6,632	21,907	-	9	-	29,724	26,994	2,474	255	3,936	764	187	-
BCP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BDHA	-	-	-	-	-	-	-	91,750	88,525	3,225	-	-	-	-	-
Break Out	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CCA	-	-	-	-	-	-	-	9,758	8,858	812	88	1,292	251	61	-
CDMPP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CEN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CEN EWMP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CREV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CWCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CWMC	-	-	-	-	-	-	-	154,933	95,183	19,899	39,851	-	-	-	-
CWMR	-	-	-	-	-	-	-	244,533	191,885	38,558	14,090	-	-	-	-
CWNB	-	-	-	-	-	-	-	802,298	640,320	117,393	44,585	725	301	22,121	-
DCP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LPHA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LTNCP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NFA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NFA ECC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PNCP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SNCP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TCP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**1,108,245**	**501,478**	**140,129**	**465,896**	**379**	**288**	**75**	**2,116,955**	**1,710,366**	**266,925**	**139,665**	**95,445**	**18,680**	**26,609**	**-**

Grouping of OM&A (lines 168 - 240)	Demand Allocators								Customer Allocators						
	Demand Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Customer Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Total
1808	99,362	47,129	11,413	40,308	338	107	67	99,362	-	-	-	-	-	-	-
1815	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1820	91,160	40,444	11,338	39,327	24	22	5	91,160	-	-	-	-	-	-	-
1830	81,251	47,125	8,500	21,029	3,696	725	175	81,251	-	-	-	-	-	-	-
1835	280,899	162,903	29,394	72,713	12,777	2,507	606	280,899	-	-	-	-	-	-	-
1840	11,050	6,445	1,167	2,813	503	99	24	11,050	-	-	-	-	-	-	-
1845	43,844	25,512	4,612	11,239	1,994	391	95	43,844	-	-	-	-	-	-	-
1850	268,139	158,189	28,814	65,958	12,204	2,396	578	268,139	-	-	-	-	-	-	-
1855	244,866	168,583	30,907	14,861	24,581	4,770	1,165	244,866	-	-	-	-	-	-	-
1860	72,986	44,839	9,374	18,773	-	-	-	72,986	-	-	-	-	-	-	-
1815-1855	511,022	292,403	56,717	133,883	22,526	4,424	1,069	511,022	-	-	-	-	-	-	-
1830 & 1835	246,809	143,140	25,823	63,883	11,227	2,203	532	246,809	-	-	-	-	-	-	-
1840 & 1845	86,524	50,361	9,106	22,162	3,936	772	187	86,524	-	-	-	-	-	-	-
BCP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BDHA	91,750	88,525	3,225	-	-	-	-	91,750	-	-	-	-	-	-	-
Break Out	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CCA	11,361	8,858	812	88	1,292	251	61	11,361	-	-	-	-	-	-	-
CDMPP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CEN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CEN EWMP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CREV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CWCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CWMC	154,933	95,183	19,899	39,851	-	-	-	154,933	-	-	-	-	-	-	-
CWMR	244,533	191,885	38,558	14,090	-	-	-	244,533	-	-	-	-	-	-	-
CWNB	825,444	640,320	117,393	44,585	725	301	22,121	825,444	-	-	-	-	-	-	-
DCP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LPHA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LTNCP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NFA	71,404	41,460	8,025	17,927	3,205	630	156	71,404	-	-	-	-	-	-	-
NFA ECC	100,616	58,424	11,252	25,322	4,511	887	219	100,616	-	-	-	-	-	-	-
O&M	2,217,990	1,457,500	268,229	399,036	63,143	12,499	17,584	2,217,990	-	-	-	-	-	-	-
PNCP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SNCP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TCP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**5,755,945**	**3,769,229**	**694,559**	**1,047,846**	**166,683**	**32,985**	**44,643**	**5,755,945**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

2006 COST ALLOCATION INFORMATION FILING
Canadian Niagara Power Inc - Fort Erie & EOP

Monday, July 14, 2008
Sheet O7 Amortization Output Worksheet - Second Run

Categorization and Allocation of Contributed Capital
Contributed Capital - 1995

Account	Description	Contributed Capital	Demand	Customer	Total	Demand Allocation 1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	Sub -total Total	Customer Allocation 1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	Sub -total	A & G Allocation 1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	Sub -total
1565	Conservation and Demand Management	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1805	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1805-1	Land Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1805-2	Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1806	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1806-1	Land Rights Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1806-2	Land Rights Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1808	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1808-2	Buildings and Fixtures < 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1810-1	Leasehold Improvements >50 kV (Wholesale)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1810-2	Leasehold Improvements <50 kV (Other)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	($5,321)	($5,321)	$0	($5,321)	($2,524)	($611)	($2,159)	($18)	($6)	($4)	($5,321)	$0	$0	$0	$0	$0	$0	$0							
1830-4	Poles, Towers and Fixtures - Primary	($359,342)	($215,605)	($143,737)	($359,342)	($95,097)	($26,990)	($93,483)	$0	($36)	$0	($215,605)	($112,070)	($10,273)	($1,108)	($16,341)	($3,171)	($774)	($143,737)							
1830-5	Poles, Towers and Fixtures - Secondary	($121,132)	($72,679)	($48,453)	($121,132)	($33,652)	($9,551)	($29,463)	$0	($13)	$0	($72,679)	($37,810)	($3,466)	($333)	($5,513)	($1,070)	($261)	($48,453)							
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	($4,182)	($4,182)	$0	($4,182)	($1,984)	($480)	($1,696)	($14)	($5)	($3)	($4,182)	$0	$0	$0	$0	$0	$0	$0							
1835-4	Overhead Conductors and Devices - Primary	($1,133,396)	($680,038)	($453,358)	($1,133,396)	($299,943)	($85,128)	($294,854)	$0	($112)	$0	($680,038)	($353,478)	($32,402)	($3,495)	($51,540)	($10,001)	($2,442)	($453,358)							
1835-5	Overhead Conductors and Devices - Secondary	($383,418)	($230,051)	($153,367)	($383,418)	($106,520)	($30,232)	($93,259)	$0	($40)	$0	($230,051)	($119,678)	($10,971)	($1,055)	($17,450)	($3,386)	($827)	($153,367)							
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1840-4	Underground Conduit - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1840-5	Underground Conduit - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1845-4	Underground Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1845-5	Underground Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1850	Line Transformers	($140,013)	($84,008)	($56,005)	($140,013)	($38,898)	($11,040)	($34,056)	$0	($15)	$0	($84,008)	($43,703)	($4,006)	($385)	($6,372)	($1,236)	($302)	($56,005)							
1855	Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1860	Meters	($50,376)	$0	($50,376)	($50,376)	$0	$0	$0	$0	$0	$0	$0	($30,948)	($6,470)	($12,958)	$0	$0	$0	($50,376)							
	Sub - Total	**($2,197,180)**	**($1,291,884)**	**($905,296)**	**($2,197,180)**	**($578,617)**	**($164,032)**	**($548,970)**	**($32)**	**($225)**	**($6)**	**($1,291,884)**	**($697,687)**	**($67,588)**	**($19,334)**	**($97,217)**	**($18,864)**	**($4,607)**	**($905,296)**							
General Plant																										
1905	Land	$0																		$0	$0	$0	$0	$0	$0	$0
1906	Land Rights	$0																		$0	$0	$0	$0	$0	$0	$0
1908	Buildings and Fixtures	$0																		$0	$0	$0	$0	$0	$0	$0
1910	Leasehold Improvements	$0																		$0	$0	$0	$0	$0	$0	$0
1915	Office Furniture and Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
1920	Computer Equipment - Hardware	$0																		$0	$0	$0	$0	$0	$0	$0
1925	Computer Software	$0																		$0	$0	$0	$0	$0	$0	$0
1930	Transportation Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
1935	Stores Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
1940	Tools, Shop and Garage Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
1945	Measurement and Testing Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
1950	Power Operated Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
1955	Communication Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
1960	Miscellaneous Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
1970	Load Management Controls - Customer Premises	$0																		$0	$0	$0	$0	$0	$0	$0
1975	Load Management Controls - Utility Premises	$0																		$0	$0	$0	$0	$0	$0	$0
1980	System Supervisory Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
1990	Other Tangible Property	$0																		$0	$0	$0	$0	$0	$0	$0
2005	Property Under Capital Leases	$0																		$0	$0	$0	$0	$0	$0	$0
2010	Electric Plant Purchased or Sold	$0																		$0	$0	$0	$0	$0	$0	$0
	Sub - Total	$0																		$0	$0	$0	$0	$0	$0	$0
	TOTAL - 1995	($2,197,180)	($1,291,884)	($905,296)	($2,197,180)	($578,617)	($164,032)	($548,970)	($32)	($225)	($6)	($1,291,884)	($697,687)	($67,588)	($19,334)	($97,217)	($18,864)	($4,607)	($905,296)	$0	$0	$0	$0	$0	$0	$0

Accumulated Depreciation - 2105 Capital Contribution

Account	Description	Accumulated Depreciation	Demand	Customer	Total	Demand Allocation 1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	Sub -total	Customer Allocation 1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	Sub -total	A & G Allocation 1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	Sub -total
1565	Conservation and Demand Management	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1805	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1805-1	Land Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1805-2	Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1806	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1806-1	Land Rights Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1806-2	Land Rights Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1808	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1808-2	Buildings and Fixtures < 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1810-2	Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1830-4	Poles, Towers and Fixtures - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1830-5	Poles, Towers and Fixtures - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1835-4	Overhead Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1835-5	Overhead Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1840-4	Underground Conduit - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							

	A	B	C	D	E	F	G	H	I	M	N	O	AA	AB	AC	AD	AH	AI	AJ	AV	AW	AX	AY	BC	BD	BE	BQ
120	1840-5	Underground Conduit - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
121	1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
122	1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
123	1845-4	Underground Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
124	1845-5	Underground Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
125	1850	Line Transformers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
126	1855	Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
127	1860	Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
128		**Sub - Total**	$0	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**							
129	**General Plant**																										
130	1905	Land	$0																		$0	$0	$0	$0	$0	$0	$0
131	1906	Land Rights	$0																		$0	$0	$0	$0	$0	$0	$0
132	1908	Buildings and Fixtures	$0																		$0	$0	$0	$0	$0	$0	$0
133	1910	Leasehold Improvements	$0																		$0	$0	$0	$0	$0	$0	$0
134	1915	Office Furniture and Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
135	1920	Computer Equipment - Hardware	$0																		$0	$0	$0	$0	$0	$0	$0
136	1925	Computer Software	$0																		$0	$0	$0	$0	$0	$0	$0
137	1930	Transportation Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
138	1935	Stores Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
139	1940	Tools, Shop and Garage Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
140	1945	Measurement and Testing Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
141	1950	Power Operated Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
142	1955	Communication Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
143	1960	Miscellaneous Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
144	1970	Load Management Controls - Customer Premises	$0																		$0	$0	$0	$0	$0	$0	$0
145	1975	Load Management Controls - Utility Premises	$0																		$0	$0	$0	$0	$0	$0	$0
146	1980	System Supervisory Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
147	1990	Other Tangible Property	$0																		$0	$0	$0	$0	$0	$0	$0
148	2005	Property Under Capital Leases	$0																		$0	$0	$0	$0	$0	$0	$0
149	2010	Electric Plant Purchased or Sold	$0																		$0	$0	$0	$0	$0	$0	$0
150		**Sub - Total**	$0																		$0	$0	$0	$0	$0	$0	$0
151																											
152		**TOTAL - 2105 CC**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
153																											
154	**Accumulated Depreciation - 2105 Fixed Assets Only**																										
155							**Demand Allocation**							**Customer Allocation**							**A & G Allocation**						
156							**1**	**2**	**3**	**7**	**8**	**9**	**Sub -total**	**1**	**2**	**3**	**7**	**8**	**9**	**Sub -total**	**1**	**2**	**3**	**7**	**8**	**9**	**Sub -total**
157	**Account**	**Description**	**Accumulated Depreciation**	**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Sub -total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Sub -total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Sub -total**
158	1565	Conservation and Demand Management	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
159	1805	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
160	1805-1	Land Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
161	1805-2	Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
162	1806	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
163	1806-1	Land Rights Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
164	1806-2	Land Rights Station <50 kV	($52,687)	($52,687)	$0	($52,687)	($24,990)	($6,052)	($21,373)	($179)	($57)	($35)	($52,687)	$0	$0	$0	$0	$0	$0	$0							
165	1808	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
166	1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
167	1808-2	Buildings and Fixtures < 50 KV	($126,744)	($126,744)	$0	($126,744)	($60,117)	($14,558)	($51,416)	($431)	($136)	($85)	($126,744)	$0	$0	$0	$0	$0	$0	$0							
168	1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
169	1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
170	1810-2	Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
171	1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
172	1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
173	1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	($63,416)	($63,416)	$0	($63,416)	($30,079)	($7,284)	($25,726)	($216)	($68)	($43)	($63,416)	$0	$0	$0	$0	$0	$0	$0							
174	1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	($1,072,303)	($1,072,303)	$0	($1,072,303)	($472,959)	($134,232)	($464,935)	$0	($177)	$0	($1,072,303)	$0	$0	$0	$0	$0	$0	$0							
175	1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
176	1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
177	1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
178	1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
179	1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
180	1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	($15,373)	($15,373)	$0	($15,373)	($7,292)	($1,766)	($6,236)	($52)	($17)	($10)	($15,373)	$0	$0	$0	$0	$0	$0	$0							
181	1830-4	Poles, Towers and Fixtures - Primary	($2,879,015)	($1,727,409)	($1,151,606)	($2,879,015)	($761,905)	($216,240)	($748,979)	$0	($286)	$0	($1,727,409)	($897,892)	($82,307)	($8,878)	($130,921)	($25,403)	($6,204)	($1,151,606)							
182	1830-5	Poles, Towers and Fixtures - Secondary	($973,435)	($584,061)	($389,374)	($973,435)	($270,436)	($76,754)	($236,770)	$0	($101)	$0	($584,061)	($303,844)	($27,853)	($2,678)	($44,303)	($8,596)	($2,099)	($389,374)							
183	1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
184	1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	($4,342)	($4,342)	$0	($4,342)	($2,059)	($499)	($1,761)	($15)	($5)	($3)	($4,342)	$0	$0	$0	$0	$0	$0	$0							
185	1835-4	Overhead Conductors and Devices - Primary	($2,591,735)	($1,555,041)	($1,036,694)	($2,591,735)	($685,879)	($194,662)	($674,243)	$0	($257)	$0	($1,555,041)	($808,297)	($74,094)	($7,992)	($117,858)	($22,869)	($5,585)	($1,036,694)							
186	1835-5	Overhead Conductors and Devices - Secondary	($877,322)	($526,393)	($350,929)	($877,322)	($243,735)	($69,175)	($213,392)	$0	($91)	$0	($526,393)	($273,844)	($25,102)	($2,414)	($39,929)	($7,748)	($1,892)	($350,929)							
187	1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
188	1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
189	1840-4	Underground Conduit - Primary	($70,301)	($42,181)	($28,120)	($70,301)	($18,605)	($5,280)	($18,289)	$0	($7)	$0	($42,181)	($21,925)	($2,010)	($217)	($3,197)	($620)	($151)	($28,120)							
190	1840-5	Underground Conduit - Secondary	($46,867)	($28,120)	($18,747)	($46,867)	($13,020)	($3,695)	($11,400)	$0	($5)	$0	($28,120)	($14,629)	($1,341)	($129)	($2,133)	($414)	($101)	($18,747)							
191	1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
192	1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
193	1845-4	Underground Conductors and Devices - Primary	($885,198)	($531,119)	($354,079)	($885,198)	($234,260)	($66,486)	($230,285)	$0	($88)	$0	($531,119)	($276,071)	($25,307)	($2,730)	($40,254)	($7,811)	($1,907)	($354,079)							
194	1845-5	Underground Conductors and Devices - Secondary	($590,100)	($354,060)	($236,040)	($590,100)	($163,940)	($46,528)	($143,531)	$0	($61)	$0	($354,060)	($184,191)	($16,884)	($1,624)	($26,857)	($5,211)	($1,273)	($236,040)							
195	1850	Line Transformers	($2,486,932)	($1,492,159)	($994,773)	($2,486,932)	($690,911)	($196,090)	($604,899)	$0	($259)	$0	($1,492,159)	($776,260)	($71,158)	($6,843)	($113,186)	($21,962)	($5,363)	($994,773)							
196	1855	Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
197	1860	Meters	($1,191,354)	$0	($1,191,354)	($1,191,354)	$0	$0	$0	$0	$0	$0	$0	($731,904)	($153,014)	($306,436)	$0	$0	$0	($1,191,354)							
198		**Sub - Total**	**($13,927,124)**	**($8,175,408)**	**($5,751,716)**	**($13,927,124)**	**($3,680,187)**	**($1,039,303)**	**($3,453,233)**	**($893)**	**($1,615)**	**($177)**	**($8,175,408)**	**($4,288,857)**	**($479,069)**	**($339,941)**	**($518,638)**	**($100,635)**	**($24,576)**	**($5,751,716)**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
199	**General Plant**																										
200	1905	Land	$0																		$0	$0	$0	$0	$0	$0	$0
201	1906	Land Rights	$0																		$0	$0	$0	$0	$0	$0	$0
202	1908	Buildings and Fixtures	($57,480)																		($33,376)	($6,428)	($14,466)	($2,577)	($507)	($125)	($57,480)
203	1910	Leasehold Improvements	$0																		$0	$0	$0	$0	$0	$0	$0
204	1915	Office Furniture and Equipment	($651,777)																		($378,463)	($72,890)	($164,031)	($29,225)	($5,748)	($1,420)	($651,777)
205	1920	Computer Equipment - Hardware	($336,373)																		($195,319)	($37,618)	($84,654)	($15,082)	($2,966)	($733)	($336,373)
206	1925	Computer Software	($637,202)																		($369,999)	($71,260)	($160,363)	($28,571)	($5,619)	($1,388)	($637,202)
207	1930	Transportation Equipment	($538,213)																		($312,520)	($60,190)	($135,451)	($24,133)	($4,746)	($1,173)	($538,213)
208	1935	Stores Equipment	($38,564)																		($22,393)	($4,313)	($9,705)	($1,729)	($340)	($84)	($38,564)
209	1940	Tools, Shop and Garage Equipment	($222,137)																		($128,987)	($24,842)	($55,905)	($9,960)	($1,959)	($484)	($222,137)
210	1945	Measurement and Testing Equipment	($105,620)																		($61,330)	($11,812)	($26,581)	($4,736)	($931)	($230)	($105,620)
211	1950	Power Operated Equipment	($22,787)																		($13,232)	($2,548)	($5,735)	($1,022)	($201)	($50)	($22,787)
212	1955	Communication Equipment	($137,705)																		($79,960)	($15,400)	($34,656)	($6,174)	($1,214)	($300)	($137,705)
213	1960	Miscellaneous Equipment	($33,349)																		($19,365)	($3,730)	($8,393)	($1,495)	($294)	($73)	($33,349)
214	1970	Load Management Controls - Customer Premises	$0																		$0	$0	$0	$0	$0	$0	$0
215	1975	Load Management Controls - Utility Premises	$0																		$0	$0	$0	$0	$0	$0	$0
216	1980	System Supervisory Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
217	1990	Other Tangible Property	$0																		$0	$0	$0	$0	$0	$0	$0
218	2005	Property Under Capital Leases	$0																		$0	$0	$0	$0	$0	$0	$0
219	2010	Electric Plant Purchased or Sold	$0																		$0	$0	$0	$0	$0	$0	$0
220		**Sub - Total**	**($2,781,207)**																		($1,614,943)	($311,032)	($699,941)	($124,704)	($24,527)	($6,060)	($2,781,207)
221																											
222		**TOTAL - 2105 FA**	($16,708,331)	($8,175,408)	($5,751,716)	($13,927,124)	($3,680,187)	($1,039,303)	($3,453,233)	($893)	($1,615)	($177)	($8,175,408)	($4,288,857)	($479,069)	($339,941)	($518,638)	($100,635)	($24,576)	($5,751,716)	($1,614,943)	($311,032)	($699,941)	($124,704)	($24,527)	($6,060)	($2,781,207)
223																											
224	**Accumulated Depreciation - 2120**																										
225							**Demand Allocation**							**Customer Allocation**							**A & G Allocation**						
226							**1**	**2**	**3**	**7**	**8**	**9**	**Sub -total**	**1**	**2**	**3**	**7**	**8**	**9**	**Sub -total**	**1**	**2**	**3**	**7**	**8**	**9**	**Sub -total**
227	**Account**	**Description**	**Accumulated Depreciation**	**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Sub -total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Sub -total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Sub -total**
228	1565	Conservation and Demand Management	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
229	1805	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
230	1805-1	Land Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
231	1805-2	Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
232	1806	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
233	1806-1	Land Rights Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
234	1806-2	Land Rights Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
235	1808	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
236	1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
237	1808-2	Buildings and Fixtures < 50 KV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
238	1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
239	1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
240	1810-2	Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
241	1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
242	1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							

	A	B	C	D	E	F	G	H	I	M	N	O	AA	AB	AC	AD	AH	AI	AJ	AV	AW	AX	AY	BC	BD	BE	BQ
243	1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
244	1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
245	1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
246	1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
247	1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
248	1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
249	1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
250	1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
251	1830-4	Poles, Towers and Fixtures - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
252	1830-5	Poles, Towers and Fixtures - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
253	1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
254	1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
255	1835-4	Overhead Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
256	1835-5	Overhead Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
257	1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
258	1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
259	1840-4	Underground Conduit - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
260	1840-5	Underground Conduit - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
261	1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
262	1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
263	1845-4	Underground Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
264	1845-5	Underground Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
265	1850	Line Transformers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
266	1855	Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
267	1860	Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
268		**Sub - Total**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
269	**General Plant**																										
270	1905	Land	$0																		$0	$0	$0	$0	$0	$0	$0
271	1906	Land Rights	$0																		$0	$0	$0	$0	$0	$0	$0
272	1908	Buildings and Fixtures	$0																		$0	$0	$0	$0	$0	$0	$0
273	1910	Leasehold Improvements	$0																		$0	$0	$0	$0	$0	$0	$0
274	1915	Office Furniture and Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
275	1920	Computer Equipment - Hardware	$0																		$0	$0	$0	$0	$0	$0	$0
276	1925	Computer Software	$0																		$0	$0	$0	$0	$0	$0	$0
277	1930	Transportation Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
278	1935	Stores Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
279	1940	Tools, Shop and Garage Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
280	1945	Measurement and Testing Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
281	1950	Power Operated Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
282	1955	Communication Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
283	1960	Miscellaneous Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
284	1970	Load Management Controls - Customer Premises	$0																		$0	$0	$0	$0	$0	$0	$0
285	1975	Load Management Controls - Utility Premises	$0																		$0	$0	$0	$0	$0	$0	$0
286	1980	System Supervisory Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
287	1990	Other Tangible Property	($11,941)																		($6,934)	($1,335)	($3,005)	($535)	($105)	($26)	($11,941)
288	2005	Property Under Capital Leases	$0																		$0	$0	$0	$0	$0	$0	$0
289	2010	Electric Plant Purchased or Sold	$0																		$0	$0	$0	$0	$0	$0	$0
290		**Sub - Total**	**($11,941)**				**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**($6,934)**	**($1,335)**	**($3,005)**	**($535)**	**($105)**	**($26)**	**($11,941)**
291																											
292		**TOTAL - 2120**	($11,941)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($6,934)	($1,335)	($3,005)	($535)	($105)	($26)	($11,941)

Categorization and Allocation of Amortization Expense - Property, Plant and Equipment - 5705

							Demand Allocation 1	2	3	7	8	9	Sub -total	Customer Allocation 1	2	3	7	8	9	Sub -total	A & G Allocation 1	2	3	7	8	9	Sub -total
300	Account	Description	Depreciation	Demand	Customer	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Sub -total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Sub -total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Sub -total
301	1565	Conservation and Demand Management	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
302	1805	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
303	1805-1	Land Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
304	1805-2	Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
305	1806	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
306	1806-1	Land Rights Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
307	1806-2	Land Rights Station <50 kV	$2,568	$2,568	$0	$2,568	$1,218	$295	$1,042	$9	$3	$2	$2,568	$0	$0	$0	$0	$0	$0	$0							
308	1808	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
309	1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
310	1808-2	Buildings and Fixtures < 50 kV	($20,442)	($20,442)	$0	($20,442)	($9,696)	($2,348)	($8,293)	($70)	($22)	($14)	($20,442)	$0	$0	$0	$0	$0	$0	$0							
311	1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
312	1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
313	1810-2	Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
314	1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
315	1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
316	1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$7,145	$7,145	$0	$7,145	$3,389	$821	$2,898	$24	$8	$5	$7,145	$0	$0	$0	$0	$0	$0	$0							
317	1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$82,763	$82,763	$0	$82,763	$36,504	$10,360	$35,885	$0	$14	$0	$82,763	$0	$0	$0	$0	$0	$0	$0							
318	1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
319	1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
320	1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
321	1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
322	1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
323	1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$1,451	$1,451	$0	$1,451	$688	$167	$589	$5	$2	$1	$1,451	$0	$0	$0	$0	$0	$0	$0							
324	1830-4	Poles, Towers and Fixtures - Primary	$294,015	$176,409	$117,606	$294,015	$77,808	$22,083	$76,488	$0	$29	$0	$176,409	$91,696	$8,406	$907	$13,370	$2,594	$634	$117,606							
325	1830-5	Poles, Towers and Fixtures - Secondary	$99,423	$59,654	$39,769	$99,423	$27,621	$7,839	$24,183	$0	$10	$0	$59,654	$31,033	$2,845	$274	$4,525	$878	$214	$39,769							
326	1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
327	1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$453	$453	$0	$453	$215	$52	$184	$2	$0	$0	$453	$0	$0	$0	$0	$0	$0	$0							
328	1835-4	Overhead Conductors and Devices - Primary	$237,740	$142,644	$95,096	$237,740	$62,916	$17,856	$61,848	$0	$24	$0	$142,644	$74,145	$6,797	$733	$10,811	$2,098	$512	$95,096							
329	1835-5	Overhead Conductors and Devices - Secondary	$80,471	$48,283	$32,188	$80,471	$22,356	$6,345	$19,573	$0	$8	$0	$48,283	$25,118	$2,302	$221	$3,662	$711	$174	$32,188							
330	1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
331	1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
332	1840-4	Underground Conduit - Primary	$5,846	$3,508	$2,338	$5,846	$1,547	$439	$1,521	$0	$1	$0	$3,508	$1,823	$167	$18	$266	$52	$13	$2,338							
333	1840-5	Underground Conduit - Secondary	$3,897	$2,338	$1,559	$3,897	$1,083	$307	$948	$0	$0	$0	$2,338	$1,216	$112	$11	$177	$34	$8	$1,559							
334	1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
335	1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
336	1845-4	Underground Conductors and Devices - Primary	$95,631	$57,379	$38,252	$95,631	$25,308	$7,183	$24,879	$0	$9	$0	$57,379	$29,825	$2,734	$295	$4,349	$844	$206	$38,252							
337	1845-5	Underground Conductors and Devices - Secondary	$63,752	$38,251	$25,501	$63,752	$17,711	$5,027	$15,506	$0	$7	$0	$38,251	$19,899	$1,824	$175	$2,902	$563	$137	$25,501							
338	1850	Line Transformers	$207,619	$124,571	$83,048	$207,619	$57,680	$16,370	$50,499	$0	$22	$0	$124,571	$64,805	$5,941	$571	$9,449	$1,833	$448	$83,048							
339	1855	Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
340	1860	Meters	$88,542	$0	$88,542	$88,542	$0	$0	$0	$0	$0	$0	$0	$54,395	$11,372	$22,775	$0	$0	$0	$88,542							
341		**Sub - Total**	**$1,250,874**	**$726,974**	**$523,900**	**$1,250,874**	**$326,349**	**$92,797**	**$307,750**	**($30)**	**$114**	**($6)**	**$726,974**	**$393,957**	**$42,499**	**$25,980**	**$49,511**	**$9,607**	**$2,346**	**$523,900**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
342																											
343	**General Plant**																										
344	1905	Land	$0																		$0	$0	$0	$0	$0	$0	$0
345	1906	Land Rights	$0																		$0	$0	$0	$0	$0	$0	$0
346	1908	Buildings and Fixtures	$7,247																		$4,208	$810	$1,824	$325	$64	$16	$7,247
347	1910	Leasehold Improvements	$0																		$0	$0	$0	$0	$0	$0	$0
348	1915	Office Furniture and Equipment	$100,611																		$58,421	$11,252	$25,321	$4,511	$887	$219	$100,611
349	1920	Computer Equipment - Hardware	$117,058																		$67,971	$13,091	$29,460	$5,249	$1,032	$255	$117,058
350	1925	Computer Software	$288,177																		$167,334	$32,228	$72,525	$12,921	$2,541	$628	$288,177
351	1930	Transportation Equipment	($52,101)																		($30,253)	($5,827)	($13,112)	($2,336)	($459)	($114)	($52,101)
352	1935	Stores Equipment	($2,571)																		($1,493)	($288)	($647)	($115)	($23)	($6)	($2,571)
353	1940	Tools, Shop and Garage Equipment	($17,093)																		($9,925)	($1,912)	($4,302)	($766)	($151)	($37)	($17,093)
354	1945	Measurement and Testing Equipment	($10,392)																		($6,034)	($1,162)	($2,615)	($466)	($92)	($23)	($10,392)
355	1950	Power Operated Equipment	($970)																		($563)	($108)	($244)	($43)	($9)	($2)	($970)
356	1955	Communication Equipment	($518)																		($301)	($58)	($130)	($23)	($5)	($1)	($518)
357	1960	Miscellaneous Equipment	($1,417)																		($823)	($158)	($357)	($64)	($12)	($3)	($1,417)
358	1970	Load Management Controls - Customer Premises	$0																		$0	$0	$0	$0	$0	$0	$0
359	1975	Load Management Controls - Utility Premises	$0																		$0	$0	$0	$0	$0	$0	$0
360	1980	System Supervisory Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
361	1990	Other Tangible Property	$0																		$0	$0	$0	$0	$0	$0	$0
362	2005	Property Under Capital Leases	$0																		$0	$0	$0	$0	$0	$0	$0
363	2010	Electric Plant Purchased or Sold	$0																		$0	$0	$0	$0	$0	$0	$0

	A	B	C	D	E	F	G	H	I	M	N	O	AA	AB	AC	AD	AH	AI	AJ	AV	AW	AX	AY	BC	BD	BE	BQ
364		Sub - Total	$428,031				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$248,542	$47,868	$107,722	$19,192	$3,775	$933	$428,031
365																											
366		TOTAL - 5705	$1,678,905	$726,974	$523,900	$1,250,874	$326,349	$92,797	$307,750	($30)	$114	($6)	$726,974	$393,957	$42,499	$25,980	$49,511	$9,607	$2,346	$523,900	$248,542	$47,868	$107,722	$19,192	$3,775	$933	$428,031

Categorization and Allocation of Amortization of Limited Term Electric Plant - 5710

	A	B	C	D	E	F	G	H	I	M	N	O	AA	AB	AC	AD	AH	AI	AJ	AV	AW	AX	AY	BC	BD	BE	BQ
371							Demand Allocation							Customer Allocation							A & G Allocation						
372							1	2	3	7	8	9	Sub -total	1	2	3	7	8	9	Sub -total	1	2	3	7	8	9	Sub -total
373	Account	Description	Depreciation	Demand	Customer	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Sub -total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Sub -total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Sub -total
374	1565	Conservation and Demand Management	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
375	1805	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
376	1805-1	Land Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
377	1805-2	Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
378	1806	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
379	1806-1	Land Rights Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
380	1806-2	Land Rights Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
381	1808	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
382	1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
383	1808-2	Buildings and Fixtures < 50 KV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
384	1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
385	1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
386	1810-2	Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
387	1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
388	1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
389	1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
390	1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
391	1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
392	1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
393	1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
394	1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
395	1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
396	1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
397	1830-4	Poles, Towers and Fixtures - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
398	1830-5	Poles, Towers and Fixtures - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
399	1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
400	1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
401	1835-4	Overhead Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
402	1835-5	Overhead Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
403	1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
404	1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
405	1840-4	Underground Conduit - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
406	1840-5	Underground Conduit - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
407	1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
408	1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
409	1845-4	Underground Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
410	1845-5	Underground Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
411	1850	Line Transformers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
412	1855	Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
413	1860	Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
414		Sub - Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
415	General Plant																										
416	1905	Land	$0																		$0	$0	$0	$0	$0	$0	$0
417	1906	Land Rights	$0																		$0	$0	$0	$0	$0	$0	$0
418	1908	Buildings and Fixtures	$0																		$0	$0	$0	$0	$0	$0	$0
419	1910	Leasehold Improvements	$0																		$0	$0	$0	$0	$0	$0	$0
420	1915	Office Furniture and Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
421	1920	Computer Equipment - Hardware	$0																		$0	$0	$0	$0	$0	$0	$0
422	1925	Computer Software	$0																		$0	$0	$0	$0	$0	$0	$0
423	1930	Transportation Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
424	1935	Stores Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
425	1940	Tools, Shop and Garage Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
426	1945	Measurement and Testing Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
427	1950	Power Operated Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
428	1955	Communication Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
429	1960	Miscellaneous Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
430	1970	Load Management Controls - Customer Premises	$0																		$0	$0	$0	$0	$0	$0	$0
431	1975	Load Management Controls - Utility Premises	$0																		$0	$0	$0	$0	$0	$0	$0
432	1980	System Supervisory Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
433	1990	Other Tangible Property	$0																		$0	$0	$0	$0	$0	$0	$0
434	2005	Property Under Capital Leases	$0																		$0	$0	$0	$0	$0	$0	$0
435	2010	Electric Plant Purchased or Sold	$0																		$0	$0	$0	$0	$0	$0	$0
436		Sub - Total	$0				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
437																											
438		TOTAL - 5710	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Categorization and Allocation of Accumulated Amortization of Electric Utility Plant - Intangibles - 5715

	A	B	C	D	E	F	G	H	I	M	N	O	AA	AB	AC	AD	AH	AI	AJ	AV	AW	AX	AY	BC	BD	BE	BQ
444							Demand Allocation							Customer Allocation							A & G Allocation						
445							1	2	3	7	8	9	Sub -total	1	2	3	7	8	9	Sub -total	1	2	3	7	8	9	Sub -total
446	Account	Description	Depreciation	Demand	Customer	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Sub -total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Sub -total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Sub -total
447	1565	Conservation and Demand Management	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
448	1805	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
449	1805-1	Land Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
450	1805-2	Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
451	1806	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
452	1806-1	Land Rights Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
453	1806-2	Land Rights Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
454	1808	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
455	1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
456	1808-2	Buildings and Fixtures < 50 KV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
457	1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
458	1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
459	1810-2	Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
460	1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
461	1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
462	1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
463	1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
464	1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
465	1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
466	1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
467	1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
468	1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
469	1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
470	1830-4	Poles, Towers and Fixtures - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
471	1830-5	Poles, Towers and Fixtures - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
472	1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
473	1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
474	1835-4	Overhead Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
475	1835-5	Overhead Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
476	1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
477	1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
478	1840-4	Underground Conduit - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
479	1840-5	Underground Conduit - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
480	1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
481	1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
482	1845-4	Underground Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							

A	B	C	D	E	F	G	H	I	M	N	O	AA	AB	AC	AD	AH	AI	AJ	AV	AW	AX	AY	BC	BD	BE	BQ
1845-5	Underground Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1850	Line Transformers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1855	Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1860	Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
	Sub - Total	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Plant																										
1905	Land	$0																		$0	$0	$0	$0	$0	$0	$0
1906	Land Rights	$0																		$0	$0	$0	$0	$0	$0	$0
1908	Buildings and Fixtures	$0																		$0	$0	$0	$0	$0	$0	$0
1910	Leasehold Improvements	$0																		$0	$0	$0	$0	$0	$0	$0
1915	Office Furniture and Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
1920	Computer Equipment - Hardware	$0																		$0	$0	$0	$0	$0	$0	$0
1925	Computer Software	$0																		$0	$0	$0	$0	$0	$0	$0
1930	Transportation Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
1935	Stores Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
1940	Tools, Shop and Garage Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
1945	Measurement and Testing Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
1950	Power Operated Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
1955	Communication Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
1960	Miscellaneous Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
1970	Load Management Controls - Customer Premises	$0																		$0	$0	$0	$0	$0	$0	$0
1975	Load Management Controls - Utility Premises	$0																		$0	$0	$0	$0	$0	$0	$0
1980	System Supervisory Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
1990	Other Tangible Property	$5,746																		$3,336	$643	$1,446	$258	$51	$13	$5,746
2005	Property Under Capital Leases	$0																		$0	$0	$0	$0	$0	$0	$0
2010	Electric Plant Purchased or Sold	$0																		$0	$0	$0	$0	$0	$0	$0
	Sub - Total	**$5,746**				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,336	$643	$1,446	$258	$51	$13	$5,746
	TOTAL - 5715	$5,746	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,336	$643	$1,446	$258	$51	$13	$5,746

Categorization and Allocation of Accum. Amortization of Electric Utility Plant- Property, Plant & Equipment - 5720

						Demand Allocation 1	2	3	7	8	9	Sub -total	Customer Allocation 1	2	3	7	8	9	Sub -total	A & G Allocation 1	2	3	7	8	9	Sub -total
Account	**Description**	**Depreciation**	**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Sub -total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Sub -total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Sub -total**
1565	Conservation and Demand Management	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1805	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1805-1	Land Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1805-2	Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1806	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1806-1	Land Rights Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1806-2	Land Rights Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1808	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1808-2	Buildings and Fixtures < 50 KV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1810-2	Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1830-4	Poles, Towers and Fixtures - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1830-5	Poles, Towers and Fixtures - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1835-4	Overhead Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1835-5	Overhead Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1840-4	Underground Conduit - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1840-5	Underground Conduit - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1845-4	Underground Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1845-5	Underground Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1850	Line Transformers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1855	Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
1860	Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
	Sub - Total	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Plant																										
1905	Land	$0																		$0	$0	$0	$0	$0	$0	$0
1906	Land Rights	$0																		$0	$0	$0	$0	$0	$0	$0
1908	Buildings and Fixtures	$0																		$0	$0	$0	$0	$0	$0	$0
1910	Leasehold Improvements	$0																		$0	$0	$0	$0	$0	$0	$0
1915	Office Furniture and Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
1920	Computer Equipment - Hardware	$0																		$0	$0	$0	$0	$0	$0	$0
1925	Computer Software	$0																		$0	$0	$0	$0	$0	$0	$0
1930	Transportation Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
1935	Stores Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
1940	Tools, Shop and Garage Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
1945	Measurement and Testing Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
1950	Power Operated Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
1955	Communication Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
1960	Miscellaneous Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
1970	Load Management Controls - Customer Premises	$0																		$0	$0	$0	$0	$0	$0	$0
1975	Load Management Controls - Utility Premises	$0																		$0	$0	$0	$0	$0	$0	$0
1980	System Supervisory Equipment	$0																		$0	$0	$0	$0	$0	$0	$0
1990	Other Tangible Property	$0																		$0	$0	$0	$0	$0	$0	$0
2005	Property Under Capital Leases	$0																		$0	$0	$0	$0	$0	$0	$0
2010	Electric Plant Purchased or Sold	$0																		$0	$0	$0	$0	$0	$0	$0
	Sub - Total	**$0**				**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
	TOTAL - 5720	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

						Demand Allocation 1	2	3	7	8	9	Sub -total	Customer Allocation 1	2	3	7	8	9	Sub -total	A & G Allocation 1	2	3	7	8	9	Sub -total
Account	**Description**		**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Sub -total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Sub -total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Sub -total**
1565	Conservation and Demand Management	100%	0%	100%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	65.71%	12.09%	17.99%	2.85%	0.56%	0.79%	100.00%							
1805	Land					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
1805-1	Land Station >50 kV	100%	100%	0%	100%	47.43%	11.49%	40.56%	0.34%	0.11%	0.07%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
1805-2	Land Station <50 kV	100%	100%	0%	100%	47.43%	11.49%	40.57%	0.34%	0.11%	0.07%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
1806	Land Rights					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
1806-1	Land Rights Station >50 kV	100%	100%	0%	100%	47.43%	11.49%	40.56%	0.34%	0.11%	0.07%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
1806-2	Land Rights Station <50 kV	100%	100%	0%	100%	47.43%	11.49%	40.57%	0.34%	0.11%	0.07%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
1808	Buildings and Fixtures					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
1808-1	Buildings and Fixtures > 50 kV	100%	100%	0%	100%	47.43%	11.49%	40.56%	0.34%	0.11%	0.07%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
1808-2	Buildings and Fixtures < 50 KV	100%	100%	0%	100%	47.43%	11.49%	40.57%	0.34%	0.11%	0.07%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
1810	Leasehold Improvements					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
1810-1	Leasehold Improvements >50 kV	100%	100%	0%	100%	47.43%	11.49%	40.56%	0.34%	0.11%	0.07%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
1810-2	Leasehold Improvements <50 kV	100%	100%	0%	100%	47.43%	11.49%	40.57%	0.34%	0.11%	0.07%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
1815	Transformer Station Equipment - Normally Primary above 50 kV	100%	100%	0%	100%	47.43%	11.49%	40.56%	0.34%	0.11%	0.07%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
1820	Distribution Station Equipment - Normally Primary below 50 kV					47.43%	11.49%	40.57%	0.34%	0.11%	0.07%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	100%	100%	0%	100%	47.43%	11.49%	40.57%	0.34%	0.11%	0.07%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	100%	100%	0%	100%	44.11%	12.52%	43.36%	0.00%	0.02%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							

	A	B	C	D	E	F	G	H	I	M	N	O	AA	AB	AC	AD	AH	AI	AJ	AV	AW	AX	AY	BC	BD	BE	BQ
606	1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	100%	0%	100%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	36.26%	14.59%	48.18%	0.63%	0.23%	0.10%	100.00%							
607	1825	Storage Battery Equipment					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
608	1825-1	Storage Battery Equipment > 50 kV	100%	100%	0%	100%	47.43%	11.49%	40.56%	0.34%	0.11%	0.07%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
609	1825-2	Storage Battery Equipment <50 kV	100%	100%	0%	100%	47.43%	11.49%	40.57%	0.34%	0.11%	0.07%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
610	1830	Poles, Towers and Fixtures					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
611	1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	100%	100%	0%	100%	47.43%	11.49%	40.57%	0.34%	0.11%	0.07%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
612	1830-4	Poles, Towers and Fixtures - Primary	100%	60%	40%	100%	44.11%	12.52%	43.36%	0.00%	0.02%	0.00%	100.00%	77.97%	7.15%	0.77%	11.37%	2.21%	0.54%	100.00%							
613	1830-5	Poles, Towers and Fixtures - Secondary	100%	60%	40%	100%	46.30%	13.14%	40.54%	0.00%	0.02%	0.00%	100.00%	78.03%	7.15%	0.69%	11.38%	2.21%	0.54%	100.00%							
614	1835	Overhead Conductors and Devices					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
615	1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	100%	100%	0%	100%	47.43%	11.49%	40.57%	0.34%	0.11%	0.07%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
616	1835-4	Overhead Conductors and Devices - Primary	100%	60%	40%	100%	44.11%	12.52%	43.36%	0.00%	0.02%	0.00%	100.00%	77.97%	7.15%	0.77%	11.37%	2.21%	0.54%	100.00%							
617	1835-5	Overhead Conductors and Devices - Secondary	100%	60%	40%	100%	46.30%	13.14%	40.54%	0.00%	0.02%	0.00%	100.00%	78.03%	7.15%	0.69%	11.38%	2.21%	0.54%	100.00%							
618	1840	Underground Conduit					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
619	1840-3	Underground Conduit - Bulk Delivery	100%	100%	0%	100%	47.43%	11.49%	40.57%	0.34%	0.11%	0.07%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
620	1840-4	Underground Conduit - Primary	100%	60%	40%	100%	44.11%	12.52%	43.36%	0.00%	0.02%	0.00%	100.00%	77.97%	7.15%	0.77%	11.37%	2.21%	0.54%	100.00%							
621	1840-5	Underground Conduit - Secondary	100%	60%	40%	100%	46.30%	13.14%	40.54%	0.00%	0.02%	0.00%	100.00%	78.03%	7.15%	0.69%	11.38%	2.21%	0.54%	100.00%							
622	1845	Underground Conductors and Devices					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
623	1845-3	Underground Conductors and Devices - Bulk Delivery	100%	100%	0%	100%	47.43%	11.49%	40.57%	0.34%	0.11%	0.07%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
624	1845-4	Underground Conductors and Devices - Primary	100%	60%	40%	100%	44.11%	12.52%	43.36%	0.00%	0.02%	0.00%	100.00%	77.97%	7.15%	0.77%	11.37%	2.21%	0.54%	100.00%							
625	1845-5	Underground Conductors and Devices - Secondary	100%	60%	40%	100%	46.30%	13.14%	40.54%	0.00%	0.02%	0.00%	100.00%	78.03%	7.15%	0.69%	11.38%	2.21%	0.54%	100.00%							
626	1850	Line Transformers	100%	60%	40%	100%	46.30%	13.14%	40.54%	0.00%	0.02%	0.00%	100.00%	78.03%	7.15%	0.69%	11.38%	2.21%	0.54%	100.00%							
627	1855	Services	100%	0%	100%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	68.85%	12.62%	6.07%	10.04%	1.95%	0.48%	100.00%							
628	1860	Meters	100%	0%	100%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	61.43%	12.84%	25.72%	0.00%	0.00%	0.00%	100.00%							
629	**General Plant**																										
630	1905	Land	100%																		58%	11%	25%	4%	1%	0%	100%
631	1906	Land Rights	100%																		58%	11%	25%	4%	1%	0%	100%
632	1908	Buildings and Fixtures	100%																		58%	11%	25%	4%	1%	0%	100%
633	1910	Leasehold Improvements	100%																		58%	11%	25%	4%	1%	0%	100%
634	1915	Office Furniture and Equipment	100%																		58%	11%	25%	4%	1%	0%	100%
635	1920	Computer Equipment - Hardware	100%																		58%	11%	25%	4%	1%	0%	100%
636	1925	Computer Software	100%																		58%	11%	25%	4%	1%	0%	100%
637	1930	Transportation Equipment	100%																		58%	11%	25%	4%	1%	0%	100%
638	1935	Stores Equipment	100%																		58%	11%	25%	4%	1%	0%	100%
639	1940	Tools, Shop and Garage Equipment	100%																		58%	11%	25%	4%	1%	0%	100%
640	1945	Measurement and Testing Equipment	100%																		58%	11%	25%	4%	1%	0%	100%
641	1950	Power Operated Equipment	100%																		58%	11%	25%	4%	1%	0%	100%
642	1955	Communication Equipment	100%																		58%	11%	25%	4%	1%	0%	100%
643	1960	Miscellaneous Equipment	100%																		58%	11%	25%	4%	1%	0%	100%
644	1970	Load Management Controls - Customer Premises	100%																		58%	11%	25%	4%	1%	0%	100%
645	1975	Load Management Controls - Utility Premises	100%																		58%	11%	25%	4%	1%	0%	100%
646	1980	System Supervisory Equipment	100%																		58%	11%	25%	4%	1%	0%	100%
647	1990	Other Tangible Property	100%																		58%	11%	25%	4%	1%	0%	100%
648	2005	Property Under Capital Leases	100%																		58%	11%	25%	4%	1%	0%	100%
649	2010	Electric Plant Purchased or Sold	100%																		58%	11%	25%	4%	1%	0%	100%

2006 COST ALLOCATION INFORMATION FILING

Canadian Niagara Power Inc - Fort Erie & EOP

Monday, July 14, 2008

Sheet E1 Categorization Worksheet - Second Run

This worksheet details how Density is derived and how Costs are Categorized.

Density of Utility

Density	Number of Customers	kM of Lines
40	18624	464

Deemed Customer Cost Component based on Survey Results

		Customer Component	
If Density is < 30 customers per kM of lines then	LOW	0.6	*All*
If Density is Between 30 and 60 customers per kM of lines then	MEDIUM	0.4	*All*
If Density is Between > 60 customers per kM of lines then	HIGH	0.35	*Distribution*
If Density is Between > 60 customers per kM of lines then	HIGH	0.3	*Transformers*

Categorization and Demand Allocation for Distribution Assets Accounts

USoA A/C #	Accounts	Categorization		
		Demand	Customer	Customer Component
	Distribution Plant			
1805	Land	DCP		0%
1805-1	Land Station >50 kV	TCP		0%
1805-2	Land Station <50 kV	DCP		0%
1806	Land Rights	DCP		0%
1806-1	Land Rights Station >50 kV	TCP		0%
1806-2	Land Rights Station <50 kV	DCP		0%
1808	Buildings and Fixtures	DCP		0%
1808-1	Buildings and Fixtures > 50 kV	TCP		0%
1808-2	Buildings and Fixtures < 50 KV	DCP		0%
1810	Leasehold Improvements	DCP		0%
1810-1	Leasehold Improvements >50 kV	TCP		0%
1810-2	Leasehold Improvements <50 kV	DCP		0%
1815	Transformer Station Equipment - Normally Primary above 50 kV	TCP		0%
1820	Distribution Station Equipment - Normally Primary below 50 kV	DCP		0%
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	DCP		0%

1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	PNCP		0%
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)		CEN	100%
1825	Storage Battery Equipment	DCP		0%
1825-1	Storage Battery Equipment > 50 kV	TCP		0%
1825-2	Storage Battery Equipment <50 kV	DCP		0%
1830	Poles, Towers and Fixtures	DNCP	CCA	40%
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	BCP		0%
1830-4	Poles, Towers and Fixtures - Primary	PNCP	CCP	40%
1830-5	Poles, Towers and Fixtures - Secondary	SNCP	CCS	40%
1835	Overhead Conductors and Devices	DNCP	CCA	40%
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	BCP		0%
1835-4	Overhead Conductors and Devices - Primary	PNCP	CCP	40%
1835-5	Overhead Conductors and Devices - Secondary	SNCP	CCS	40%
1840	Underground Conduit	DNCP	CCA	40%
1840-3	Underground Conduit - Bulk Delivery	BCP		0%
1840-4	Underground Conduit - Primary	PNCP	CCP	40%
1840-5	Underground Conduit - Secondary	SNCP	CCS	40%
1845	Underground Conductors and Devices	DNCP	CCA	40%
1845-3	Underground Conductors and Devices - Bulk Delivery	BCP		0%
1845-4	Underground Conductors and Devices - Primary	PNCP	CCP	40%
1845-5	Underground Conductors and Devices - Secondary	SNCP	CCS	40%
1850	Line Transformers	LTNCP	CCLT	40%
1855	Services		CWCS	100%
1860	Meters		CWMC	100%
1565	Conservation and Demand Management Expenditures and Recoveries		CDMPP	100%
	Accumulated Amortization			
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	See I4 BO Assets		
	Operation			
5005	Operation Supervision and Engineering	1815-1855 D	1815-1855 C	40%
5010	Load Dispatching	1815-1855 D	1815-1855 C	40%
5012	Station Buildings and Fixtures Expense	1808 D		0%
5014	Transformer Station Equipment - Operation Labour	1815 D		0%
5015	Transformer Station Equipment - Operation Supplies and Expenses	1815 D		0%
5016	Distribution Station Equipment - Operation Labour	1820 D		0%
5017	Distribution Station Equipment - Operation Supplies and Expenses	1820 D		0%
5020	Overhead Distribution Lines and Feeders - Operation Labour	1830 & 1835 D	1830 & 1835 C	40%
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	1830 & 1835 D	1830 & 1835 C	40%
5030	Overhead Subtransmission Feeders - Operation	1830 & 1835 D		0%
5035	Overhead Distribution Transformers- Operation	1850 D	1850 C	40%

5040	Underground Distribution Lines and Feeders - Operation Labour	1840 & 1845 D	1840 & 1845 C	40%
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	1840 & 1845 D	1840 & 1845 C	40%
5050	Underground Subtransmission Feeders - Operation	1840 & 1845 D		0%
5055	Underground Distribution Transformers - Operation	1850 D	1850 C	40%
5065	Meter Expense		CWMC	100%
5070	Customer Premises - Operation Labour		CCA	100%
5075	Customer Premises - Materials and Expenses		CCA	100%
5085	Miscellaneous Distribution Expense	1815-1855 D	1815-1855 C	40%
5090	Underground Distribution Lines and Feeders - Rental Paid	1840 & 1845 D	1840 & 1845 C	40%
5095	Overhead Distribution Lines and Feeders - Rental Paid	1830 & 1835 D	1830 & 1835 C	40%
	Maintenance			
5105	Maintenance Supervision and Engineering	1815-1855 D	1815-1855 C	40%
5110	Maintenance of Buildings and Fixtures - Distribution Stations	1808 D		0%
5112	Maintenance of Transformer Station Equipment	1815 D		0%
5114	Maintenance of Distribution Station Equipment	1820 D		0%
5120	Maintenance of Poles, Towers and Fixtures	1830 D	1830 C	40%
5125	Maintenance of Overhead Conductors and Devices	1835 D	1835 C	40%
5130	Maintenance of Overhead Services		1855 C	100%
5135	Overhead Distribution Lines and Feeders - Right of Way	1830 & 1835 D	1830 & 1835 C	40%
5145	Maintenance of Underground Conduit	1840 D	1840 C	40%
5150	Maintenance of Underground Conductors and Devices	1845 D	1845 C	40%
5155	Maintenance of Underground Services		1855 C	100%
5160	Maintenance of Line Transformers	1850 D	1850 C	40%
5175	Maintenance of Meters		1860 C	100%
5305	Supervision		CWNB	100%
5310	Meter Reading Expense		CWMR	100%
5315	Customer Billing		CWNB	100%
5320	Collecting		CWNB	100%
5325	Collecting- Cash Over and Short		CWNB	100%
5330	Collection Charges		CWNB	100%
5335	Bad Debt Expense		BDHA	100%
5340	Miscellaneous Customer Accounts Expenses		CWNB	100%

2006 COST ALLOCATION INFORMATION FILING

Canadian Niagara Power Inc - Fort Erie &

Monday, July 14, 2008

Sheet E2 Allocator Worksheet - Second Run

Details:
The worksheet below details how allocators are derived.

			1	2	3	7	8	9
Explanation	**ID and Factors**	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
Demand Allocators								
1 cp								
Transformation CP	TCP1	100.00%	47.23%	11.75%	40.91%	0.03%	0.01%	0.07%
Bulk Delivery (SubTransmission) CP	BCP1	100.00%	47.24%	11.75%	40.90%	0.03%	0.01%	0.07%
Distribution CP (Total System)	DCP1	100.00%	47.24%	11.75%	40.90%	0.03%	0.01%	0.07%
4 cp								
Transformation CP	TCP4	100.00%	50.67%	10.78%	38.24%	0.19%	0.06%	0.06%
Bulk Delivery (SubTransmission) CP	BCP4	100.00%	50.67%	10.78%	38.24%	0.19%	0.06%	0.06%
Distribution CP (Total System)	DCP4	100.00%	50.67%	10.78%	38.24%	0.19%	0.06%	0.06%
12 cp								
Transformation CP	TCP12	100.00%	47.43%	11.49%	40.56%	0.34%	0.11%	0.07%
Bulk Delivery (SubTransmission) CP	BCP12	100.00%	47.43%	11.49%	40.57%	0.34%	0.11%	0.07%
Distribution CP (Total System)	DCP12	100.00%	47.43%	11.49%	40.57%	0.34%	0.11%	0.07%
NON CO_INCIDENT PEAK								
1 NCP								
Distribution NCP (Total System)	DNCP1	100.00%	47.17%	12.72%	40.09%	0.00%	0.02%	0.00%
Primary NCP	PNCP1	100.00%	43.62%	13.18%	43.18%	0.00%	0.02%	0.00%
Line Transformer NCP	LTNCP1	100.00%	45.78%	13.84%	40.36%	0.00%	0.02%	0.00%
Secondary NCP	SNCP1	100.00%	45.78%	13.84%	40.36%	0.00%	0.02%	0.00%
4 NCP								
Distribution NCP (Total System)	DNCP4	100.00%	47.81%	12.09%	40.09%	0.00%	0.02%	0.00%
Primary NCP	PNCP4	100.00%	44.11%	12.52%	43.36%	0.00%	0.02%	0.00%
Line Transformer NCP	LTNCP4	100.00%	46.30%	13.14%	40.54%	0.00%	0.02%	0.00%
Secondary NCP	SNCP4	100.00%	46.30%	13.14%	40.54%	0.00%	0.02%	0.00%
12 NCP								
Distribution NCP (Total System)	DNCP12	100.00%	45.36%	12.21%	42.42%	0.00%	0.01%	0.00%
Primary NCP	PNCP12	100.00%	40.87%	12.71%	46.41%	0.00%	0.01%	0.00%
Line Transformer NCP	LTNCP12	100.00%	43.06%	13.39%	43.54%	0.00%	0.01%	0.00%
Secondary NCP	SNCP12	100.00%	43.06%	13.39%	43.54%	0.00%	0.01%	0.00%
Demand Allocators - Composite								
DEMAND 1815-1855	1815-1855 D	100.00%	45.01%	12.75%	42.22%	0.00%	0.02%	0.00%
DEMAND 1808	1808 D	100.00%	47.43%	11.49%	40.57%	0.34%	0.11%	0.07%
DEMAND 1815	1815 D	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DEMAND 1820	1820 D	100.00%	44.37%	12.44%	43.14%	0.03%	0.02%	0.01%
DEMAND 1815 & 1820	1815 & 1820 D	100.00%	44.37%	12.44%	43.14%	0.03%	0.02%	0.01%
DEMAND 1830	1830 D	100.00%	44.67%	12.67%	42.64%	0.00%	0.02%	0.00%
DEMAND 1835	1835 D	100.00%	44.67%	12.67%	42.64%	0.00%	0.02%	0.00%
DEMAND 1830 & 1835	1830 & 1835 D	100.00%	44.67%	12.67%	42.64%	0.00%	0.02%	0.00%
DEMAND 1840	1840 D	100.00%	45.21%	12.83%	41.94%	0.00%	0.02%	0.00%
DEMAND 1845	1845 D	100.00%	44.99%	12.77%	42.23%	0.00%	0.02%	0.00%

	A	B	C	D	E	F	J	K	L
65	DEMAND 1840 & 1845	1840 & 1845 D	100.00%	45.01%	12.77%	42.20%	0.00%	0.02%	0.00%
66	DEMAND 1850	1850 D	100.00%	46.30%	13.14%	40.54%	0.00%	0.02%	0.00%
67	DEMAND 1855	1855 D	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
68	DEMAND 1860	1860 D	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
69									
70	CUSTOMER ALLOCATORS								
71									
72	Billing Data								
73	kWh	CEN	100.00%	36.26%	14.59%	48.18%	0.63%	0.23%	0.10%
74	kW	CDEM	100.00%	0.00%	0.00%	97.99%	1.47%	0.54%	0.00%
75	kWh - Excl WMP	CEN EWMP	100.00%	36.26%	14.59%	48.18%	0.63%	0.23%	0.10%
76									
77	Dollar Billed (per 2006 EDR)	CREV	100.00%	48.88%	15.63%	34.31%	0.71%	0.27%	0.20%
78	Bad Debt 3 Year Historical Average	BDHA	100.00%	96.48%	3.52%	0.00%	0.00%	0.00%	0.00%
79	Late Payment 3 Year Historical Average	LPHA	100.00%	48.01%	16.32%	34.52%	0.71%	0.24%	0.19%
80									
81	Number of Bills	CNB	100.00%	89.74%	8.23%	0.89%	0.10%	0.42%	0.62%
82	Number of Connections (Unmetered)	CCON	100.00%	0.00%	0.00%	0.00%	80.55%	15.63%	3.82%
83									
85									
86	Total Number of Customer	CCA	100.00%	77.97%	7.15%	0.78%	11.37%	2.21%	0.54%
87	Subtransmission Customer Base	CCB	100.00%	47.02%	5.95%	0.52%	37.47%	7.27%	1.78%
88	Primary Feeder Customer Base	CCP	100.00%	77.97%	7.15%	0.77%	11.37%	2.21%	0.54%
89	Line Transformer Customer Base	CCLT	100.00%	78.03%	7.15%	0.69%	11.38%	2.21%	0.54%
90	Secondary Feeder Customer Base	CCS	100.00%	78.03%	7.15%	0.69%	11.38%	2.21%	0.54%
91									
92	Weighted - Services	CWCS	100.00%	68.85%	12.62%	6.07%	10.04%	1.95%	0.48%
93	Weighted Meter -Capital	CWMC	100.00%	61.43%	12.84%	25.72%	0.00%	0.00%	0.00%
94	Weighted Meter Reading	CWMR	100.00%	78.47%	15.77%	5.76%	0.00%	0.00%	0.00%
95	Weighted Bills	CWNB	100.00%	77.57%	14.22%	5.40%	0.09%	0.04%	2.68%
96									
97	CUSTOMER ALLOCATORS - Composite								
98									
99	CUSTOMER 1815-1855	1815-1855 C	100.00%	75.53%	8.62%	2.17%	11.01%	2.14%	0.52%
100	CUSTOMER 1808	1808 C	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
101	CUSTOMER 1815	1815 C	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
102	CUSTOMER 1820	1820 C	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
103	CUSTOMER 1815 & 1820	1815 & 1820 C	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
104	CUSTOMER 1830	1830 C	100.00%	77.99%	7.15%	0.75%	11.37%	2.21%	0.54%
105	CUSTOMER 1835	1835 C	100.00%	77.99%	7.15%	0.75%	11.37%	2.21%	0.54%
106	CUSTOMER 1830 & 1835	1830 & 1835 C	100.00%	77.99%	7.15%	0.75%	11.37%	2.21%	0.54%
107	CUSTOMER 1840	1840 C	100.00%	78.00%	7.15%	0.73%	11.37%	2.21%	0.54%
108	CUSTOMER 1845	1845 C	100.00%	77.99%	7.15%	0.74%	11.37%	2.21%	0.54%
109	CUSTOMER 1840 & 1845	1840 & 1845 C	100.00%	78.00%	7.15%	0.74%	11.37%	2.21%	0.54%
110	CUSTOMER 1850	1850 C	100.00%	78.03%	7.15%	0.69%	11.38%	2.21%	0.54%
111	CUSTOMER 1855	1855 C	100.00%	68.85%	12.62%	6.07%	10.04%	1.95%	0.48%
112	CUSTOMER 1860	1860 C	100.00%	61.43%	12.84%	25.72%	0.00%	0.00%	0.00%
113									
114	**Composite Allocators**								
115	Net Fixed Assets	NFA	100.00%	58.06%	11.24%	25.11%	4.49%	0.88%	0.22%
116	Net Fixed Assets Excluding Capital Contribution	NFA ECC	100.00%	58.07%	11.18%	25.17%	4.48%	0.88%	0.22%
117	5005-5340	O&M	100.00%	65.71%	12.09%	17.99%	2.85%	0.56%	0.79%

2006 COST ALLOCATION INFORMATION

Canadian Niagara Power Inc - Fort Erie &

Ontario

Monday, July 14, 2008

Sheet E3 Demand Allocator Worksheet - Second Run

Instructions:
Input sheet for Demand Allocators.

PLCC WATTS
400

		1	2	3	7	8	9
Customer Classes	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
CCA	21,534	16,789	1,539	167	2,448	475	116
CCB	6,534	3,072	389	34	2,448	475	116
CCP	21,533	16,789	1,539	166	2,448	475	116
CCLT	21,515	16,789	1,539	148	2,448	475	116
CCS	21,515	16,789	1,539	148	2,448	475	116
PLCC-CCA	8,614	6,716	616	67	979	190	46
PLCC-CCB	2,614	1,229	156	14	979	190	46
PLCC-CCP	8,613	6,716	616	66	979	190	46
PLCC-CCLT	8,606	6,716	616	59	979	190	46
PLCC-CCS	8,606	6,716	616	59	979	190	46
1NCP							
DNCP1	80,039	37,920	10,045	31,197	626	203	48

	A	B	C	D	E	I	J	K
34	**PNCP1**	**79,797**	37,920	10,045	30,955	626	203	48
35	**LTNCP1**	**76,410**	37,920	10,045	27,568	626	203	48
36	**SNCP1**	**76,410**	37,920	10,045	27,568	626	203	48
37								
38	**PLCC - 1NCP**							
39	**DNCP1A**	**77,779**	36,692	9,890	31,183	0	13	1
40	**PNCP1A**	**71,537**	31,205	9,430	30,888	0	13	1
41	**LTNCP1A**	**68,157**	31,205	9,430	27,508	0	13	1
42	**SNCP1A**	**68,157**	31,205	9,430	27,508	0	13	1
43								
44	**4 NCP**							
45								
46	**DNCP4**	**304,782**	146,322	36,367	118,609	2,500	805	179
47	**PNCP4**	**303,872**	146,322	36,367	117,699	2,500	805	179
48	**LTNCP4**	**290,998**	146,322	36,367	104,825	2,500	805	179
49	**SNCP4**	**290,998**	146,322	36,367	104,825	2,500	805	179
50								
51	**PLCC - 4NCP**							
52	**DNCP4A**	**295,751**	141,407	35,744	118,555	0	45	0
53	**PNCP4A**	**270,842**	119,460	33,904	117,433	0	45	0
54	**LTNCP4A**	**257,997**	119,460	33,904	104,588	0	45	0
55	**SNCP4A**	**257,997**	119,460	33,904	104,588	0	45	0
56								
57	**12NCP**							
58								
59	**DNCP12**	**813,467**	371,505	97,876	333,745	7,498	2,355	489
60	**PNCP12**	**810,851**	371,505	97,876	331,129	7,498	2,355	489
61	**LTNCP12**	**774,605**	371,505	97,876	294,883	7,498	2,355	489
62	**SNCP12**	**774,605**	371,505	97,876	294,883	7,498	2,355	489
63								
64	**PLCC - 12NCP**							
65	**DNCP12A**	**786,425**	356,759	96,009	333,582	0	75	0
66	**PNCP12A**	**711,814**	290,918	90,489	330,332	0	75	0
67	**LTNCP12A**	**675,653**	290,918	90,489	294,172	0	75	0
68	**SNCP12A**	**675,653**	290,918	90,489	294,172	0	75	0

2006 COST ALLOCATION INFORMATION FILING

Canadian Niagara Power Inc - Fort Erie & EOP

Monday, July 14, 2008

Sheet E4 Trial Balance Allocation Detail Worksheet - Second Run

Details:
The worksheet below details how costs are treated, categorized, and grouped.

This sheet shows what accounts are included in the COSS, and how they are grouped into working capital and rate base. It shows how accounts are categorized in the customer and demand related costs. It will then show how the categorized costs are allocated to customer and demand related components. It will also show how Miscellaneous Revenue and General Plant and Administration costs are allocated. FInally, it will show how costs are being grouped together for presentation purposes.

Uniform System of Accounts - Detail Accounts:					Classification and Allocation			Allocation Demand Related	Allocation Customer Related	Allocation A&G Related	Allocation Misc Related				
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint	Demand ID	Customer ID	A & G ID	Misc ID	cp	ncp	non-demand	FINAL
1565	Conservation and Demand Management Expenditures and Recoveries	CDM Expenditures and Recoveries	dp			O&M			O&M						
1608	Franchises and Consents	Other Distribution Assets	gp							NFA ECC					
1805	Land		dp	DDCP											
1805-1	Land Station >50 kV		dp	TCP	TCP12			TCP12				TCP12			TCP12
1805-2	Land Station <50 kV		dp	DCP	DCP12			DCP12				DCP12			DCP12
1806	Land Rights		dp	DDCP											
1806-1	Land Rights Station >50 kV		dp	TCP	TCP12			TCP12				TCP12			TCP12
1806-2	Land Rights Station <50 kV		dp	DCP	DCP12			DCP12				DCP12			DCP12
1808	Buildings and Fixtures		dp	DDCP											
1808-1	Buildings and Fixtures > 50 kV		dp	TCP	TCP12			TCP12				TCP12			TCP12
1808-2	Buildings and Fixtures < 50 KV		dp	DCP	DCP12			DCP12				DCP12			DCP12
1810	Leasehold Improvements		dp	DDCP											
1810-1	Leasehold Improvements >50 kV		dp	TCP	TCP12			TCP12				TCP12			TCP12
1810-2	Leasehold Improvements <50 kV		dp	DCP	DCP12			DCP12				DCP12			DCP12
1815	Transformer Station Equipment - Normally Primary above 50 kV		dp	TCP	TCP12			TCP12				TCP12			TCP12
1820	Distribution Station Equipment - Normally Primary below 50 kV		dp	DCP	DCP12			DCP12				DCP12			DCP12
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)		dp	DCP	DCP12			DCP12				DCP12			DCP12
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)		dp	PNCP	PNCP4			PNCP4					PNCP4		PNCP4
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)		dp			CEN			CEN						
1825	Storage Battery Equipment		dp	DDCP											
1825-1	Storage Battery Equipment > 50 kV		dp	TCP	TCP12			TCP12				TCP12			TCP12
1825-2	Storage Battery Equipment <50 kV		dp	DCP	DCP12			DCP12				DCP12			DCP12
1830	Poles, Towers and Fixtures		dp	DDNCP											
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery		dp	BCP	BCP12			BCP12				BCP12			BCP12
1830-4	Poles, Towers and Fixtures - Primary		dp	PNCP	PNCP4	CCP	x	PNCP4	CCP				PNCP4		PNCP4
1830-5	Poles, Towers and Fixtures - Secondary		dp	SNCP	SNCP4	CCS	x	SNCP4	CCS				SNCP4		SNCP4
1835	Overhead Conductors and Devices		dp	DDNCP											
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery		dp	BCP	BCP12			BCP12				BCP12			BCP12
1835-4	Overhead Conductors and Devices - Primary		dp	PNCP	PNCP4	CCP	x	PNCP4	CCP				PNCP4		PNCP4
1835-5	Overhead Conductors and Devices - Secondary		dp	SNCP	SNCP4	CCS	x	SNCP4	CCS				SNCP4		SNCP4
1840	Underground Conduit		dp	DDNCP											
1840-3	Underground Conduit - Bulk Delivery	Land and Buildings	dp	BCP	BCP12			BCP12				BCP12			BCP12
1840-4	Underground Conduit - Primary	Land and Buildings	dp	PNCP	PNCP4	CCP	x	PNCP4	CCP				PNCP4		PNCP4
1840-5	Underground Conduit - Secondary	Land and Buildings	dp	SNCP	SNCP4	CCS	x	SNCP4	CCS				SNCP4		SNCP4
1845	Underground Conductors and Devices	Land and Buildings	dp	DDNCP											
1845-3	Underground Conductors and Devices - Bulk Delivery	TS Primary Above 50	dp	BCP	BCP12			BCP12				BCP12			BCP12
1845-4	Underground Conductors and Devices - Primary	DS	dp	PNCP	PNCP4	CCP	x	PNCP4	CCP				PNCP4		PNCP4
1845-5	Underground Conductors and Devices - Secondary	Other Distribution Assets	dp	SNCP	SNCP4	CCS	x	SNCP4	CCS				SNCP4		SNCP4
1850	Line Transformers	Poles, Wires	dp	LTNCP	LTNCP4	CCLT	x	LTNCP4	CCLT				LTNCP4		LTNCP4
1855	Services	Services and Meters	dp			CWCS			CWCS						
1860	Meters	Services and Meters	dp			CWMC			CWMC						
1905	Land	Land and Buildings	gp							NFA ECC					
1906	Land Rights	Land and Buildings	gp							NFA ECC					
1908	Buildings and Fixtures	General Plant	gp							NFA ECC					
1910	Leasehold Improvements	General Plant	gp							NFA ECC					

Uniform System of Accounts - Detail Accounts:					Classification and Allocation			Allocation Demand Related	Allocation Customer Related	Allocation A&G Related	Allocation Misc Related				
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint	Demand ID	Customer ID	A & G ID	Misc ID	cp	ncp	non-demand	FINAL
1915	Office Furniture and Equipment	Equipment	gp							NFA ECC					
1920	Computer Equipment - Hardware	IT Assets	gp							NFA ECC					
1925	Computer Software	IT Assets	gp							NFA ECC					
1930	Transportation Equipment	Equipment	gp							NFA ECC					
1935	Stores Equipment	Equipment	gp							NFA ECC					
1940	Tools, Shop and Garage Equipment	Equipment	gp							NFA ECC					
1945	Measurement and Testing Equipment	Equipment	gp							NFA ECC					
1950	Power Operated Equipment	Equipment	gp							NFA ECC					
1955	Communication Equipment	Equipment	gp							NFA ECC					
1960	Miscellaneous Equipment	Equipment	gp							NFA ECC					
1970	Load Management Controls - Customer Premises	Other Distribution Assets	gp							NFA ECC					
1975	Load Management Controls - Utility Premises	Other Distribution Assets	gp							NFA ECC					
1980	System Supervisory Equipment	Other Distribution Assets	gp							NFA ECC					
1990	Other Tangible Property	Other Distribution Assets	gp							NFA ECC					
1995	Contributions and Grants - Credit	Contributions and Grants	co		Break out	Breakout		Break out	Breakout						
2005	Property Under Capital Leases	Other Distribution Assets	gp							NFA ECC					
2010	Electric Plant Purchased or Sold	Other Distribution Assets	gp							NFA ECC					
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	Accumulated Amortization	accum dep		Break out	Breakout		Break out	Breakout						
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	Accumulated Amortization	accum dep		Break out	Breakout		Break out	Breakout						
3046	Balance Transferred From Income	Equity	NI								NFA				
4080	Distribution Services Revenue	Distribution Services Revenue	CREV								CREV				
4082	Retail Services Revenues	Other Distribution Revenue	mi								CWNB				
4084	Service Transaction Requests (STR) Revenues	Other Distribution Revenue	mi								CWNB				
4090	Electric Services Incidental to Energy Sales	Other Distribution Revenue	mi								CWNB				
4205	Interdepartmental Rents	Other Distribution Revenue	mi								NFA				
4210	Rent from Electric Property	Other Distribution Revenue	mi								NFA				
4215	Other Utility Operating Income	Other Distribution Revenue	mi								NFA				
4220	Other Electric Revenues	Other Distribution Revenue	mi								NFA				
4225	Late Payment Charges	Late Payment Charges	mi								LPHA				
4235	Miscellaneous Service Revenues	Specific Service Charges	mi								CWNB				
4240	Provision for Rate Refunds	Other Distribution Revenue	mi								NFA				
4245	Government Assistance Directly Credited to Income	Other Distribution Revenue	mi								NFA				
4305	Regulatory Debits	Other Income & Deductions	mi								NFA				
4310	Regulatory Credits	Other Income & Deductions	mi								NFA				
4315	Revenues from Electric Plant Leased to Others	Other Income & Deductions	mi								NFA				
4320	Expenses of Electric Plant Leased to Others	Other Income & Deductions	mi								NFA				
4325	Revenues from Merchandise, Jobbing, Etc.	Other Income & Deductions	mi								NFA				
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	Other Income & Deductions	mi								NFA				
4335	Profits and Losses from Financial Instrument Hedges	Other Income & Deductions	mi								NFA				
4340	Profits and Losses from Financial Instrument Investments	Other Income & Deductions	mi								NFA				
4345	Gains from Disposition of Future Use Utility Plant	Other Income & Deductions	mi								NFA				
4350	Losses from Disposition of Future Use Utility Plant	Other Income & Deductions	mi								NFA				
4355	Gain on Disposition of Utility and Other Property	Other Income & Deductions	mi								NFA				
4360	Loss on Disposition of Utility and Other Property	Other Income & Deductions	mi								NFA				
4365	Gains from Disposition of Allowances for Emission	Other Income & Deductions	mi								NFA				
4370	Losses from Disposition of Allowances for Emission	Other Income & Deductions	mi								NFA				
4390	Miscellaneous Non-Operating Income	Other Income & Deductions	mi								NFA				
4395	Rate-Payer Benefit Including Interest	Other Income & Deductions	mi								NFA				
4398	Foreign Exchange Gains and Losses, Including Amortization	Other Income & Deductions	mi								NFA				
4405	Interest and Dividend Income	Other Income & Deductions	mi								NFA				
4415	Equity in Earnings of Subsidiary Companies	Other Income & Deductions	mi								NFA				

Uniform System of Accounts - Detail Accounts:					Classification and Allocation			Allocation Demand Related	Allocation Customer Related	Allocation A&G Related	Allocation Misc Related					
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint	Demand ID	Customer ID	A & G ID	Misc ID		cp	ncp	non-demand	FINAL
4705	Power Purchased	Power Supply Expenses (Working Capital)	cop							CEN EWMP						
4708	Charges-WMS	Power Supply Expenses (Working Capital)	cop							CEN EWMP						
4710	Cost of Power Adjustments	Power Supply Expenses (Working Capital)	cop							CEN EWMP						
4712	Charges-One-Time	Power Supply Expenses (Working Capital)	cop							CEN EWMP						
4714	Charges-NW	Power Supply Expenses (Working Capital)	cop							CEN						
4715	System Control and Load Dispatching	Other Power Supply Expenses	cop							CEN EWMP						
4716	Charges-CN	Power Supply Expenses (Working Capital)	cop							CEN						
4730	Rural Rate Assistance Expense	Power Supply Expenses (Working Capital)	cop							CEN EWMP						
5005	Operation Supervision and Engineering	Operation (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x	1815-1855 D	1815-1855 C						1815-1855 D	1815-1855 D
5010	Load Dispatching	Operation (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x	1815-1855 D	1815-1855 C						1815-1855 D	1815-1855 D
5012	Station Buildings and Fixtures Expense	Operation (Working Capital)	di	1808 D	1808 D	1808 C		1808 D	1808 C						1808 D	1808 D
5014	Transformer Station Equipment - Operation Labour	Operation (Working Capital)	di	1815 D	1815 D	1815 C		1815 D	1815 C						1815 D	1815 D
5015	Transformer Station Equipment - Operation Supplies and Expenses	Operation (Working Capital)	di	1815 D	1815 D	1815 C		1815 D	1815 C						1815 D	1815 D
5016	Distribution Station Equipment - Operation Labour	Operation (Working Capital)	di	1820 D	1820 D	1820 C		1820 D	1820 C						1820 D	1820 D
5017	Distribution Station Equipment - Operation Supplies and Expenses	Operation (Working Capital)	di	1820 D	1820 D	1820 C		1820 D	1820 C						1820 D	1820 D
5020	Overhead Distribution Lines and Feeders - Operation Labour	Operation (Working Capital)	di	1830 & 1835 D	1830 & 1835 D	1830 & 1835 C	x	1830 & 1835 D	1830 & 1835 C						1830 & 1835 D	1830 & 1835 D
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	Operation (Working Capital)	di	1830 & 1835 D	1830 & 1835 D	1830 & 1835 C	x	1830 & 1835 D	1830 & 1835 C						1830 & 1835 D	1830 & 1835 D
5030	Overhead Subtransmission Feeders - Operation	Operation (Working Capital)	di	1830 & 1835 D	1830 & 1835 D	1830 & 1835 C		1830 & 1835 D	1830 & 1835 C						1830 & 1835 D	1830 & 1835 D
5035	Overhead Distribution Transformers- Operation	Operation (Working Capital)	di	1850 D	1850 D	1850 C	x	1850 D	1850 C						1850 D	1850 D
5040	Underground Distribution Lines and Feeders - Operation Labour	Operation (Working Capital)	di	1840 & 1845 D	1840 & 1845 D	1840 & 1845 C	x	1840 & 1845 D	1840 & 1845 C						1840 & 1845 D	1840 & 1845 D
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	Operation (Working Capital)	di	1840 & 1845 D	1840 & 1845 D	1840 & 1845 C	x	1840 & 1845 D	1840 & 1845 C						1840 & 1845 D	1840 & 1845 D
5050	Underground Subtransmission Feeders - Operation	Operation (Working Capital)	di	1840 & 1845 D	1840 & 1845 D	1840 & 1845 C		1840 & 1845 D	1840 & 1845 C						1840 & 1845 D	1840 & 1845 D
5055	Underground Distribution Transformers - Operation	Operation (Working Capital)	di	1850 D	1850 D	1850 C	x	1850 D	1850 C						1850 D	1850 D
5065	Meter Expense	Operation (Working Capital)	cu			CWMC			CWMC							
5070	Customer Premises - Operation Labour	Operation (Working Capital)	cu			CCA			CCA							
5075	Customer Premises - Materials and Expenses	Operation (Working Capital)	cu			CCA			CCA							
5085	Miscellaneous Distribution Expense	Operation (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x	1815-1855 D	1815-1855 C						1815-1855 D	1815-1855 D
5090	Underground Distribution Lines and Feeders - Rental Paid	Operation (Working Capital)	di	1840 & 1845 D	1840 & 1845 D	1840 & 1845 C	x	1840 & 1845 D	1840 & 1845 C						1840 & 1845 D	1840 & 1845 D
5095	Overhead Distribution Lines and Feeders - Rental Paid	Operation (Working Capital)	di	1830 & 1835 D	1830 & 1835 D	1830 & 1835 C	x	1830 & 1835 D	1830 & 1835 C						1830 & 1835 D	1830 & 1835 D
5096	Other Rent	Operation (Working Capital)	di							O&M						
5105	Maintenance Supervision and Engineering	Maintenance (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x	1815-1855 D	1815-1855 C						1815-1855 D	1815-1855 D
5110	Maintenance of Buildings and Fixtures - Distribution Stations	Maintenance (Working Capital)	di	1808 D	1808 D	1808 C		1808 D	1808 C						1808 D	1808 D
5112	Maintenance of Transformer Station Equipment	Maintenance (Working Capital)	di	1815 D	1815 D	1815 C		1815 D	1815 C						1815 D	1815 D
5114	Maintenance of Distribution Station Equipment	Maintenance (Working Capital)	di	1820 D	1820 D	1820 C		1820 D	1820 C						1820 D	1820 D
5120	Maintenance of Poles, Towers and Fixtures	Maintenance (Working Capital)	di	1830 D	1830 D	1830 C	x	1830 D	1830 C						1830 D	1830 D
5125	Maintenance of Overhead Conductors and Devices	Maintenance (Working Capital)	di	1835 D	1835 D	1835 C	x	1835 D	1835 C						1835 D	1835 D
5130	Maintenance of Overhead Services	Maintenance (Working Capital)	di	1855 D	1855 D	1855 C		1855 D	1855 C						1855 D	1855 D
5135	Overhead Distribution Lines and Feeders - Right of Way	Maintenance (Working Capital)	di	1830 & 1835 D	1830 & 1835 D	1830 & 1835 C	x	1830 & 1835 D	1830 & 1835 C						1830 & 1835 D	1830 & 1835 D
5145	Maintenance of Underground Conduit	Maintenance (Working Capital)	di	1840 D	1840 D	1840 C	x	1840 D	1840 C						1840 D	1840 D
5150	Maintenance of Underground Conductors and Devices	Maintenance (Working Capital)	di	1845 D	1845 D	1845 C	x	1845 D	1845 C						1845 D	1845 D
5155	Maintenance of Underground Services	Maintenance (Working Capital)	di	1855 D	1855 D	1855 C		1855 D	1855 C						1855 D	1855 D
5160	Maintenance of Line Transformers	Maintenance (Working Capital)	di	1850 D	1850 D	1850 C	x	1850 D	1850 C						1850 D	1850 D

Uniform System of Accounts - Detail Accounts:					Classification and Allocation			Allocation Demand Related	Allocation Customer Related	Allocation A&G Related	Allocation Misc Related				
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint	Demand ID	Customer ID	A & G ID	Misc ID	cp	ncp	non-demand	FINAL
5175	Maintenance of Meters	Maintenance (Working Capital)	cu	1860 D	1860 D	1860 C		1860 D	1860 C					1860 D	1860 D
5305	Supervision	Billing and Collection (Working Capital)	cu			CWNB			CWNB						
5310	Meter Reading Expense	Billing and Collection (Working Capital)	cu			CWMR			CWMR						
5315	Customer Billing	Billing and Collection (Working Capital)	cu			CWNB			CWNB						
5320	Collecting	Billing and Collection (Working Capital)	cu			CWNB			CWNB						
5325	Collecting- Cash Over and Short	Billing and Collection (Working Capital)	cu			CWNB			CWNB						
5330	Collection Charges	Billing and Collection (Working Capital)	cu			CWNB			CWNB						
5335	Bad Debt Expense	Bad Debt Expense (Working Capital)	cu			BDHA			BDHA						
5340	Miscellaneous Customer Accounts Expenses	Billing and Collection (Working Capital)	cu			CWNB			CWNB						
5405	Supervision	Community Relations (Working Capital)	ad							O&M					
5410	Community Relations - Sundry	Community Relations (Working Capital)	ad							O&M					
5415	Energy Conservation	Community Relations - CDM (Working Capital)	ad							O&M					
5420	Community Safety Program	Community Relations (Working Capital)	ad							NFA ECC					
5425	Miscellaneous Customer Service and Informational Expenses	Community Relations (Working Capital)	ad							O&M					
5505	Supervision	Other Distribution Expenses	ad							O&M					
5510	Demonstrating and Selling Expense	Other Distribution Expenses	ad							O&M					
5515	Advertising Expense	Advertising Expenses	ad							O&M					
5520	Miscellaneous Sales Expense	Other Distribution Expenses	ad							O&M					
5605	Executive Salaries and Expenses	Administrative and General Expenses (Working Capital)	ad							O&M					
5610	Management Salaries and Expenses	Administrative and General Expenses (Working Capital)	ad							O&M					
5615	General Administrative Salaries and Expenses	Administrative and General Expenses (Working Capital)	ad							O&M					
5620	Office Supplies and Expenses	Administrative and General Expenses (Working Capital)	ad							O&M					
5625	Administrative Expense Transferred Credit	Administrative and General Expenses (Working Capital)	ad							O&M					
5630	Outside Services Employed	Administrative and General Expenses (Working Capital)	ad							O&M					
5635	Property Insurance	Insurance Expense (Working Capital)	ad							NFA ECC					
5640	Injuries and Damages	Administrative and General Expenses (Working Capital)	ad							O&M					
5645	Employee Pensions and Benefits	Administrative and General Expenses (Working Capital)	ad							O&M					
5650	Franchise Requirements	Administrative and General Expenses (Working Capital)	ad							O&M					
5655	Regulatory Expenses	Administrative and General Expenses (Working Capital)	ad							O&M					
5660	General Advertising Expenses	Advertising Expenses	ad							O&M					
5665	Miscellaneous General Expenses	Administrative and General Expenses (Working Capital)	ad							O&M					
5670	Rent	Administrative and General Expenses (Working Capital)	ad							O&M					
5675	Maintenance of General Plant	Administrative and General Expenses (Working Capital)	ad							O&M					
5680	Electrical Safety Authority Fees	Administrative and General Expenses (Working Capital)	ad							O&M					
5685	Independent Market Operator Fees and Penalties	Power Supply Expenses (Working Capital)	cop							NFA ECC					
5705	Amortization Expense - Property, Plant, and Equipment	Amortization of Assets	dep	PRORATED	Break out	Breakout			Breakout					PRORATED	PRORATED
5710	Amortization of Limited Term Electric Plant	Amortization of Assets	dep	PRORATED	Break out	Breakout			Breakout					PRORATED	PRORATED
5715	Amortization of Intangibles and Other Electric Plant	Amortization of Assets	dep	PRORATED	Break out	Breakout			Breakout					PRORATED	PRORATED
5720	Amortization of Electric Plant Acquisition Adjustments	Other Amortization - Unclassified	dep	PRORATED	Break out	Breakout			Breakout					PRORATED	PRORATED

Uniform System of Accounts - Detail Accounts:					Classification and Allocation			Allocation Demand Related	Allocation Customer Related	Allocation A&G Related	Allocation Misc Related				
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint	Demand ID	Customer ID	A & G ID	Misc ID	cp	ncp	non-demand	FINAL
5730	Amortization of Unrecovered Plant and Regulatory Study Costs	Amortization of Assets	dep							O&M					
5735	Amortization of Deferred Development Costs	Amortization of Assets	dep							O&M					
5740	Amortization of Deferred Charges	Amortization of Assets	dep							O&M					
6005	Interest on Long Term Debt	Interest Expense - Unclassifed	INT							NFA					
6105	Taxes Other Than Income Taxes	Other Distribution Expenses	ad							NFA					
6110	Income Taxes	Income Tax Expense - Unclassified	Input							NFA					
6205	Donations	Charitable Contributions	ad							O&M					
6210	Life Insurance	Insurance Expense (Working Capital)	ad							O&M					
6215	Penalties	Other Distribution Expenses	ad							O&M					
6225	Other Deductions	Other Distribution Expenses	ad							O&M					

2006 COST ALLOCATION INFORMATION FILING
Canadian Niagara Power Inc - Fort Erie & EOP

Monday, July 14, 2008
Sheet E5 Reconciliation Worksheet - Second Run

Details:
The worksheet below shows reconciliation of costs included and excluded in the Trial Balance.

USoA Account #	Accounts	Financial Statement	Financial Statement - Asset Break Out includes Acc Dep and Contributed Capital	Adjusted TB	Excluded from COSS	Excluded	Included	Balance in O5	Difference	Balance in O4 Summary	Difference
1565	Conservation and Demand Management Expenditures and Recoveries	$0		$0		$0	$0	$0	$0	$0	$0
1608	Franchises and Consents	$0		$0		$0	$0	$0	$0	$0	$0
1805	Land		$0	$0		$0	$0	$0	$0	$0	$0
1805-1	Land Station >50 kV		$0	$0		$0	$0	$0	$0	$0	$0
1805-2	Land Station <50 kV		$0	$0		$0	$0	$0	$0	$0	$0
1806	Land Rights		$0	$0		$0	$0	$0	$0	$0	$0
1806-1	Land Rights Station >50 kV		$0	$0		$0	$0	$0	$0	$0	$0
1806-2	Land Rights Station <50 kV		$104,138	$104,138		$0	$104,138	$104,138	$0	$104,138	$0
1808	Buildings and Fixtures		$0	$0		$0	$0	$0	$0	$0	$0
1808-1	Buildings and Fixtures > 50 kV		$0	$0		$0	$0	$0	$0	$0	$0
1808-2	Buildings and Fixtures < 50 KV		$2,845,621	$2,845,621		$0	$2,845,621	$2,845,621	$0	$2,845,621	$0
1810	Leasehold Improvements		$0	$0		$0	$0	$0	$0	$0	$0
1810-1	Leasehold Improvements >50 kV		$0	$0		$0	$0	$0	$0	$0	$0
1810-2	Leasehold Improvements <50 kV		$0	$0		$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment - Normally Primary above 50 kV		$0	$0		$0	$0	$0	$0	$0	$0
1820	Distribution Station Equipment - Normally Primary below 50 kV		$0	$0		$0	$0	$0	$0	$0	$0
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)		$229,590	$229,590		$0	$229,590	$229,590	$0	$229,590	$0
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)		$2,713,055	$2,713,055		$0	$2,713,055	$2,713,055	$0	$2,713,055	$0
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)		$0	$0		$0	$0	$0	$0	$0	$0
1825	Storage Battery Equipment		$0	$0		$0	$0	$0	$0	$0	$0
1825-1	Storage Battery Equipment > 50 kV		$0	$0		$0	$0	$0	$0	$0	$0
1825-2	Storage Battery Equipment <50 kV		$0	$0		$0	$0	$0	$0	$0	$0
1830	Poles, Towers and Fixtures		$0	$0		$0	$0	$0	$0	$0	$0
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery		$26,530	$26,530		$0	$26,530	$26,530	$0	$26,530	$0
1830-4	Poles, Towers and Fixtures - Primary		$7,229,346	$7,229,346		$0	$7,229,346	$7,229,346	$0	$7,229,346	$0
1830-5	Poles, Towers and Fixtures - Secondary		$2,445,640	$2,445,640		$0	$2,445,640	$2,445,640	$0	$2,445,640	$0
1835	Overhead Conductors and Devices		$0	$0		$0	$0	$0	$0	$0	$0
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery		$5,658	$5,658		$0	$5,658	$5,658	$0	$5,658	$0
1835-4	Overhead Conductors and Devices - Primary		$6,049,294	$6,049,294		$0	$6,049,294	$6,049,294	$0	$6,049,294	$0
1835-5	Overhead Conductors and Devices - Secondary		$2,048,135	$2,048,135		$0	$2,048,135	$2,048,135	$0	$2,048,135	$0
1840	Underground Conduit		$0	$0		$0	$0	$0	$0	$0	$0
1840-3	Underground Conduit - Bulk Delivery		$0	$0		$0	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary		$241,813	$241,813		$0	$241,813	$241,813	$0	$241,813	$0
1840-5	Underground Conduit - Secondary		$244,542	$244,542		$0	$244,542	$244,542	$0	$244,542	$0
1845	Underground Conductors and Devices		$0	$0		$0	$0	$0	$0	$0	$0
1845-3	Underground Conductors and Devices - Bulk Delivery		$0	$0		$0	$0	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary		$2,259,706	$2,259,706		$0	$2,259,706	$2,259,706	$0	$2,259,706	$0
1845-5	Underground Conductors and Devices - Secondary		$1,506,443	$1,506,443		$0	$1,506,443	$1,506,443	$0	$1,506,443	$0
1850	Line Transformers		$7,102,674	$7,102,674		$0	$7,102,674	$7,102,674	$0	$7,102,674	$0
1855	Services		$4,293,321	$4,293,321		$0	$4,293,321	$4,293,321	$0	$4,293,321	$0
1860	Meters		$2,402,778	$2,402,778		$0	$2,402,778	$2,402,778	$0	$2,402,778	$0
1905	Land	$0	$0	$0		$0	$0	$0	$0	$0	$0
1906	Land Rights	$0	$0	$0		$0	$0	$0	$0	$0	$0
1908	Buildings and Fixtures	$0	$386,539	$386,539		$0	$386,539	$386,539	$0	$386,539	$0
1910	Leasehold Improvements	$0	$0	$0		$0	$0	$0	$0	$0	$0
1915	Office Furniture and Equipment	$0	$1,150,790	$1,150,790		$0	$1,150,790	$1,150,790	$0	$1,150,790	$0
1920	Computer Equipment - Hardware	$0	$629,528	$629,528		$0	$629,528	$629,528	$0	$629,528	$0
1925	Computer Software	$0	$1,351,102	$1,351,102		$0	$1,351,102	$1,351,102	$0	$1,351,102	$0
1930	Transportation Equipment	$0	$413,247	$413,247		$0	$413,247	$413,247	$0	$413,247	$0
1935	Stores Equipment	$0	$96,772	$96,772		$0	$96,772	$96,772	$0	$96,772	$0
1940	Tools, Shop and Garage Equipment	$0	$623,491	$623,491		$0	$623,491	$623,491	$0	$623,491	$0
1945	Measurement and Testing Equipment	$0	$296,485	$296,485		$0	$296,485	$296,485	$0	$296,485	$0
1950	Power Operated Equipment	$0	$66,375	$66,375		$0	$66,375	$66,375	$0	$66,375	$0
1955	Communication Equipment	$0	$314,169	$314,169		$0	$314,169	$314,169	$0	$314,169	$0
1960	Miscellaneous Equipment	$0	$86,998	$86,998		$0	$86,998	$86,998	$0	$86,998	$0
1970	Load Management Controls - Customer Premises	$0	$0	$0		$0	$0	$0	$0	$0	$0
1975	Load Management Controls - Utility Premises	$0	$0	$0		$0	$0	$0	$0	$0	$0
1980	System Supervisory Equipment	$0	$0	$0		$0	$0	$0	$0	$0	$0
1990	Other Tangible Property	$0	$0	$0		$0	$0	$0	$0	$0	$0
1995	Contributions and Grants - Credit	($2,197,180)	$0	($2,197,180)		$0	($2,197,180)	($2,197,180)	$0	($2,197,180)	($0)
2005	Property Under Capital Leases	$0	$0	$0		$0	$0	$0	$0	$0	$0
2010	Electric Plant Purchased or Sold	$0	$0	$0		$0	$0	$0	$0	$0	$0
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	($16,708,331)		($16,708,331)		$0	($16,708,331)	($16,708,331)	$0	($16,708,331)	($0)
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	($11,941)		($11,941)		$0	($11,941)	($11,941)	$0	($11,941)	($0)
3046	Balance Transferred From Income	($1,494,893)		($1,494,893)		$0	($1,494,893)	($1,494,893)	$0	($1,494,893)	$0
4080	Distribution Services Revenue	($9,810,770)		($9,810,770)		$0	($9,810,770)	($9,810,770)	$0	($9,810,770)	$0
4082	Retail Services Revenues	($6,455)		($6,455)		$0	($6,455)	($6,455)	$0	($6,455)	$0
4084	Service Transaction Requests (STR) Revenues	($80)		($80)		$0	($80)	($80)	$0	($80)	$0
4090	Electric Services Incidental to Energy Sales	$0		$0		$0	$0	$0	$0	$0	$0
4205	Interdepartmental Rents	$0		$0		$0	$0	$0	$0	$0	$0
4210	Rent from Electric Property	$99,716		$99,716		$0	$99,716	$99,716	$0	$99,716	$0
4215	Other Utility Operating Income	$0		$0		$0	$0	$0	$0	$0	$0
4220	Other Electric Revenues	($133,181)		($133,181)		$0	($133,181)	($133,181)	$0	($133,181)	$0
4225	Late Payment Charges	($71,821)		($71,821)		$0	($71,821)	($71,821)	$0	($71,821)	$0

4235	Miscellaneous Service Revenues	($442,265)	($442,265)	$0	($442,265)	($442,265)	$0	($442,265)	$0
4240	Provision for Rate Refunds	$0	$0	$0	$0	$0	$0	$0	$0
4245	Government Assistance Directly Credited to Income	$0	$0	$0	$0	$0	$0	$0	$0
4305	Regulatory Debits	$0	$0	$0	$0	$0	$0	$0	$0
4310	Regulatory Credits	$0	$0	$0	$0	$0	$0	$0	$0
4315	Revenues from Electric Plant Leased to Others	$0	$0	$0	$0	$0	$0	$0	$0
4320	Expenses of Electric Plant Leased to Others	$0	$0	$0	$0	$0	$0	$0	$0
4325	Revenues from Merchandise, Jobbing, Etc.	($1,695)	($1,695)	$0	($1,695)	($1,695)	$0	($1,695)	$0
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	($28,338)	($28,338)	$0	($28,338)	($28,338)	$0	($28,338)	$0
4335	Profits and Losses from Financial Instrument Hedges	$0	$0	$0	$0	$0	$0	$0	$0
4340	Profits and Losses from Financial Instrument Investments	$0	$0	$0	$0	$0	$0	$0	$0
4345	Gains from Disposition of Future Use Utility Plant	$0	$0	$0	$0	$0	$0	$0	$0
4350	Losses from Disposition of Future Use Utility Plant	$0	$0	$0	$0	$0	$0	$0	$0
4355	Gain on Disposition of Utility and Other Property	$0	$0	$0	$0	$0	$0	$0	$0
4360	Loss on Disposition of Utility and Other Property	$11,503	$11,503	$0	$11,503	$11,503	$0	$11,503	$0
4365	Gains from Disposition of Allowances for Emission	$0	$0	$0	$0	$0	$0	$0	$0
4370	Losses from Disposition of Allowances for Emission	$0	$0	$0	$0	$0	$0	$0	$0
4390	Miscellaneous Non-Operating Income	$0	$0	$0	$0	$0	$0	$0	$0
4395	Rate-Payer Benefit Including Interest	$0	$0	$0	$0	$0	$0	$0	$0
4398	Foreign Exchange Gains and Losses, Including Amortization	($22,682)	($22,682)	$0	($22,682)	($22,682)	$0	($22,682)	$0
4405	Interest and Dividend Income	$77,395	$77,395	$0	$77,395	$77,395	$0	$77,395	$0
4415	Equity in Earnings of Subsidiary Companies	$0	$0	$0	$0	$0	$0	$0	$0
4705	Power Purchased	$18,583,495	$18,583,495	$0	$18,583,495	$18,583,495	$0	$18,583,495	$0
4708	Charges-WMS	$2,242,395	$2,242,395	$0	$2,242,395	$2,242,395	$0	$2,242,395	$0
4710	Cost of Power Adjustments	$963,849	$963,849	$0	$963,849	$963,849	$0	$963,849	$0
4712	Charges-One-Time	$0	$0	$0	$0	$0	$0	$0	$0
4714	Charges-NW	$2,481,440	$2,481,440	$0	$2,481,440	$2,481,440	$0	$2,481,440	$0
4715	System Control and Load Dispatching	$0	$0	$0	$0	$0	$0	$0	$0
4716	Charges-CN	$2,228,634	$2,228,634	$0	$2,228,634	$2,228,634	$0	$2,228,634	$0
4730	Rural Rate Assistance Expense	$0	$0	$0	$0	$0	$0	$0	$0
5005	Operation Supervision and Engineering	$14,048	$14,048	$0	$14,048	$14,048	$0	$14,048	$0
5010	Load Dispatching	$145,095	$145,095	$0	$145,095	$145,095	$0	$145,095	$0
5012	Station Buildings and Fixtures Expense	$94,038	$94,038	$0	$94,038	$94,038	$0	$94,038	$0
5014	Transformer Station Equipment - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0
5015	Transformer Station Equipment - Operation Supplies and Expenses	$0	$0	$0	$0	$0	$0	$0	$0
5016	Distribution Station Equipment - Operation Labour	$51,573	$51,573	$0	$51,573	$51,573	$0	$51,573	$0
5017	Distribution Station Equipment - Operation Supplies and Expenses	$3,978	$3,978	$0	$3,978	$3,978	$0	$3,978	$0
5020	Overhead Distribution Lines and Feeders - Operation Labour	$48,025	$48,025	$0	$48,025	$48,025	$0	$48,025	$0
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$22,235	$22,235	$0	$22,235	$22,235	$0	$22,235	$0
5030	Overhead Subtransmission Feeders - Operation	$0	$0	$0	$0	$0	$0	$0	$0
5035	Overhead Distribution Transformers- Operation	$51,894	$51,894	$0	$51,894	$51,894	$0	$51,894	$0
5040	Underground Distribution Lines and Feeders - Operation Labour	$85,572	$85,572	$0	$85,572	$85,572	$0	$85,572	$0
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$952	$952	$0	$952	$952	$0	$952	$0
5050	Underground Subtransmission Feeders - Operation	$0	$0	$0	$0	$0	$0	$0	$0
5055	Underground Distribution Transformers - Operation	$15,178	$15,178	$0	$15,178	$15,178	$0	$15,178	$0
5065	Meter Expense	$154,933	$154,933	$0	$154,933	$154,933	$0	$154,933	$0
5070	Customer Premises - Operation Labour	$1,955	$1,955	$0	$1,955	$1,955	$0	$1,955	$0
5075	Customer Premises - Materials and Expenses	$9,406	$9,406	$0	$9,406	$9,406	$0	$9,406	$0
5085	Miscellaneous Distribution Expense	$309,633	$309,633	$0	$309,633	$309,633	$0	$309,633	$0
5090	Underground Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0
5095	Overhead Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0
5096	Other Rent	$2,135	$2,135	$0	$2,135	$2,135	$0	$2,135	$0
5105	Maintenance Supervision and Engineering	$42,247	$42,247	$0	$42,247	$42,247	$0	$42,247	$0
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$5,324	$5,324	$0	$5,324	$5,324	$0	$5,324	$0
5112	Maintenance of Transformer Station Equipment	$0	$0	$0	$0	$0	$0	$0	$0
5114	Maintenance of Distribution Station Equipment	$35,608	$35,608	$0	$35,608	$35,608	$0	$35,608	$0
5120	Maintenance of Poles, Towers and Fixtures	$81,251	$81,251	$0	$81,251	$81,251	$0	$81,251	$0
5125	Maintenance of Overhead Conductors and Devices	$280,899	$280,899	$0	$280,899	$280,899	$0	$280,899	$0
5130	Maintenance of Overhead Services	$211,250	$211,250	$0	$211,250	$211,250	$0	$211,250	$0
5135	Overhead Distribution Lines and Feeders - Right of Way	$176,549	$176,549	$0	$176,549	$176,549	$0	$176,549	$0
5145	Maintenance of Underground Conduit	$11,050	$11,050	$0	$11,050	$11,050	$0	$11,050	$0
5150	Maintenance of Underground Conductors and Devices	$43,844	$43,844	$0	$43,844	$43,844	$0	$43,844	$0
5155	Maintenance of Underground Services	$33,617	$33,617	$0	$33,617	$33,617	$0	$33,617	$0
5160	Maintenance of Line Transformers	$201,067	$201,067	$0	$201,067	$201,067	$0	$201,067	$0
5175	Maintenance of Meters	$72,986	$72,986	$0	$72,986	$72,986	$0	$72,986	$0
5305	Supervision	$0	$0	$0	$0	$0	$0	$0	$0
5310	Meter Reading Expense	$244,533	$244,533	$0	$244,533	$244,533	$0	$244,533	$0
5315	Customer Billing	$348,370	$348,370	$0	$348,370	$348,370	$0	$348,370	$0
5320	Collecting	$114,921	$114,921	$0	$114,921	$114,921	$0	$114,921	$0
5325	Collecting- Cash Over and Short	$626	$626	$0	$626	$626	$0	$626	$0
5330	Collection Charges	$4,262	$4,262	$0	$4,262	$4,262	$0	$4,262	$0
5335	Bad Debt Expense	$91,750	$91,750	$0	$91,750	$91,750	$0	$91,750	$0
5340	Miscellaneous Customer Accounts Expenses	$357,265	$357,265	$0	$357,265	$357,265	$0	$357,265	$0

5405	Supervision	$0		$0		$0	$0	$0	$0	$0	$0
5410	Community Relations - Sundry	$0		$0		$0	$0	$0	$0	$0	$0
5415	Energy Conservation	$0		$0		$0	$0	$0	$0	$0	$0
5420	Community Safety Program	$0		$0		$0	$0	$0	$0	$0	$0
5425	Miscellaneous Customer Service and Informational Expenses	$0		$0		$0	$0	$0	$0	$0	$0
5505	Supervision	$0		$0		$0	$0	$0	$0	$0	$0
5510	Demonstrating and Selling Expense	$0		$0		$0	$0	$0	$0	$0	$0
5515	Advertising Expense	$0		$0		$0	$0	$0	$0	$0	$0
5520	Miscellaneous Sales Expense	$0		$0		$0	$0	$0	$0	$0	$0
5605	Executive Salaries and Expenses	$1,063,679		$1,063,679		$0	$1,063,679	$1,063,679	$0	$1,063,679	$0
5610	Management Salaries and Expenses	$0		$0		$0	$0	$0	$0	$0	$0
5615	General Administrative Salaries and Expenses	$1,994,625		$1,994,625		$0	$1,994,625	$1,994,625	$0	$1,994,625	$0
5620	Office Supplies and Expenses	$577,668		$577,668		$0	$577,668	$577,668	$0	$577,668	$0
5625	Administrative Expense Transferred Credit	($3,125,910)		($3,125,910)		$0	($3,125,910)	($3,125,910)	$0	($3,125,910)	$0
5630	Outside Services Employed	$232,930		$232,930		$0	$232,930	$232,930	$0	$232,930	$0
5635	Property Insurance	$100,616		$100,616		$0	$100,616	$100,616	$0	$100,616	$0
5640	Injuries and Damages	$125		$125		$0	$125	$125	$0	$125	$0
5645	Employee Pensions and Benefits	$404,529		$404,529		$0	$404,529	$404,529	$0	$404,529	$0
5650	Franchise Requirements	$0		$0		$0	$0	$0	$0	$0	$0
5655	Regulatory Expenses	$88,458		$88,458		$0	$88,458	$88,458	$0	$88,458	$0
5660	General Advertising Expenses	$6,402		$6,402		$0	$6,402	$6,402	$0	$6,402	$0
5665	Miscellaneous General Expenses	$245,884		$245,884		$0	$245,884	$245,884	$0	$245,884	$0
5670	Rent	$350,519		$350,519		$0	$350,519	$350,519	$0	$350,519	$0
5675	Maintenance of General Plant	$376,947		$376,947		$0	$376,947	$376,947	$0	$376,947	$0
5680	Electrical Safety Authority Fees	$0		$0		$0	$0	$0	$0	$0	$0
5685	Independent Market Operator Fees and Penalties	$0		$0		$0	$0	$0	$0	$0	$0
5705	Amortization Expense - Property, Plant, and Equipment	$1,678,905		$1,678,905		$0	$1,678,905	$1,678,905	$0	$1,678,905	($0)
5710	Amortization of Limited Term Electric Plant	$0		$0		$0	$0	$0	$0	$0	$0
5715	Amortization of Intangibles and Other Electric Plant	$5,746		$5,746		$0	$5,746	$5,746	$0	$5,746	($0)
5720	Amortization of Electric Plant Acquisition Adjustments	$0		$0		$0	$0	$0	$0	$0	$0
5730	Amortization of Unrecovered Plant and Regulatory Study Costs	$0		$0		$0	$0	$0	$0	$0	$0
5735	Amortization of Deferred Development Costs	$0		$0		$0	$0	$0	$0	$0	$0
5740	Amortization of Deferred Charges	$0		$0		$0	$0	$0	$0	$0	$0
6005	Interest on Long Term Debt	$1,177,975		$1,177,975		$0	$1,177,975	$1,177,975	$0	$1,177,975	$0
6105	Taxes Other Than Income Taxes	$71,404		$71,404		$0	$71,404	$71,404	$0	$71,404	$0
6110	Income Taxes	$163,414		$163,414		$0	$163,414	$163,414	$0	$163,414	$0
6205	Donations	$0		$0		$0	$0	$0	$0	$0	$0
6210	Life Insurance	$0		$0		$0	$0	$0	$0	$0	$0
6215	Penalties	$0		$0		$0	$0	$0	$0	$0	$0
6225	Other Deductions	$0		$0		$0	$0	$0	$0	$0	$0
	Total	**$4,540,778**	**$47,163,782**	**$51,704,560**		**$0**	**$51,704,560**	**$51,704,560**	**$0**	**$51,704,561**	**($1)**
					Control	**$51,704,560**					

Grouping by Allocator	Adjusted TB	Excluded from COSS	Excluded	Included	Balance in O5	Difference	Balance in O4 Summary	Difference
1808	$ 99,362	$ -	$ -	$ 99,362	$ 99,362	$ -	$ 99,362	$ -
1815	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1820	$ 91,160	$ -	$ -	$ 91,160	$ 91,160	$ -	$ 91,160	$ -
1830	$ 81,251	$ -	$ -	$ 81,251	$ 81,251	$ -	$ 81,251	$ -
1835	$ 280,899	$ -	$ -	$ 280,899	$ 280,899	$ -	$ 280,899	$ -
1840	$ 11,050	$ -	$ -	$ 11,050	$ 11,050	$ -	$ 11,050	$ -
1845	$ 43,844	$ -	$ -	$ 43,844	$ 43,844	$ -	$ 43,844	$ -
1850	$ 268,139	$ -	$ -	$ 268,139	$ 268,139	$ -	$ 268,139	$ -
1855	$ 244,866	$ -	$ -	$ 244,866	$ 244,866	$ -	$ 244,866	$ -
1860	$ 72,986	$ -	$ -	$ 72,986	$ 72,986	$ -	$ 72,986	$ -
1815-1855	$ 511,022	$ -	$ -	$ 511,022	$ 511,022	$ -	$ 511,022	$ -
1830 & 1835	$ 246,809	$ -	$ -	$ 246,809	$ 246,809	$ -	$ 246,809	$ -
1840 & 1845	$ 86,524	$ -	$ -	$ 86,524	$ 86,524	$ -	$ 86,524	$ -
BCP	$ 32,188	$ -	$ -	$ 32,188	$ 32,188	$ -	$ 32,188	$ -
BDHA	$ 91,750	$ -	$ -	$ 91,750	$ 91,750	$ -	$ 91,750	$ -
Break Out	$ (17,232,802)	$ -	$ -	$ (17,232,802)	$ (17,232,802)	$ -	$ (17,232,801)	$ (1)
CCA	$ 11,361	$ -	$ -	$ 11,361	$ 11,361	$ -	$ 11,361	$ -
CDMPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEN	$ 4,710,074	$ -	$ -	$ 4,710,074	$ 4,710,074	$ -	$ 4,710,074	$ -
CEN EWMP	$ 21,789,738	$ -	$ -	$ 21,789,738	$ 21,789,738	$ -	$ 21,789,738	$ -
CREV	$ (9,810,770)	$ -	$ -	$ (9,810,770)	$ (9,810,770)	$ -	$ (9,810,770)	$ -
CWCS	$ 4,293,321	$ -	$ -	$ 4,293,321	$ 4,293,321	$ -	$ 4,293,321	$ -
CWMC	$ 2,557,711	$ -	$ -	$ 2,557,711	$ 2,557,711	$ -	$ 2,557,711	$ -
CWMR	$ 244,533	$ -	$ -	$ 244,533	$ 244,533	$ -	$ 244,533	$ -
CWNB	$ 376,644	$ -	$ -	$ 376,644	$ 376,644	$ -	$ 376,644	$ -
DCP	$ 3,179,350	$ -	$ -	$ 3,179,350	$ 3,179,350	$ -	$ 3,179,350	$ -
LPHA	$ (71,821)	$ -	$ -	$ (71,821)	$ (71,821)	$ -	$ (71,821)	$ -
LTNCP	$ 7,102,674	$ -	$ -	$ 7,102,674	$ 7,102,674	$ -	$ 7,102,674	$ -
NFA	$ (79,382)	$ -	$ -	$ (79,382)	$ (79,382)	$ -	$ (79,382)	$ -
NFA ECC	$ 5,516,112	$ -	$ -	$ 5,516,112	$ 5,516,112	$ -	$ 5,516,112	$ -
O&M	$ 2,217,990	$ -	$ -	$ 2,217,990	$ 2,217,990	$ -	$ 2,217,990	$ -
PNCP	$ 18,493,215	$ -	$ -	$ 18,493,215	$ 18,493,215	$ -	$ 18,493,215	$ -
SNCP	$ 6,244,760	$ -	$ -	$ 6,244,760	$ 6,244,760	$ -	$ 6,244,760	$ -
TCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	**$ 51,704,560**	**$ -**	**$ -**	**$ 51,704,560**	**$ 51,704,560**	**$ -**	**$ 51,704,561**	**$ (1)**

HARMONIZED RATE DESIGN

Overview

The rate design provides a thorough overview of the derivation of the harmonized electricity distribution rates for the delivery of electricity to the customers of CNPI – Fort Erie and CNPI - Gananoque. The design begins with the definition of the base revenue requirement and culminates in the class specific fixed and variable charges for the delivery of electricity. CNPI has used an Excel spreadsheet model, Harmonized_DxRateDesign_20080815.xls, which is provided in Exhibit 10, Tab 1, Schedule 3, Appendix A (Rate Design Model) as the tool for determination of distribution rates.

The 2009 service revenue requirement is the combined service revenue requirements previously determined in the Application for CNPI – Fort Erie and CNPI – Gananoque. The service revenue is based on costs forecasted for 2009 Test Year, where the service revenue requirement is determined by the formula below:

Service Revenue Requirement = (Rate Base X Cost of Capital) + Distribution Expenses + Taxes

Before the service revenue requirement can be allocated to the classes and distribution rates developed, it is necessary to isolate amounts that are associated with other regulated charges and other forms of revenue. The service revenue requirement net of these other sources of revenue is the base revenue requirement. These other revenues, described as revenue offsets are detailed in Exhibit 3, Tab 3, (Other Distribution Revenue). The base revenue requirement is allocated to the customer classes and rates are calculated with both fixed monthly charges and variable per unit charges. The rates have been calculated using the rate design model referenced above.

Rate Design Model

CNPI has prepared and included an Excel worksheet model, Harmonized_DxRateDesign_20080815.xls, to aid in developing the 2009 electricity distribution rates. The worksheet is provided electronically with this Application and a copy is provided in Exhibit 9, Tab 1, Schedule 1, Appendix A. Briefly, the model functions as follows:

Tab	Description
Revenue Requirement	The revenue requirement for the 2006 Board Approved EDR and the 2009 revenue requirement as determined by this Application. These are combined for the purposes of harmonizing rates.
Forecast Data	This is the actual and forecast customer counts, weather normalized energy and demand quantities for the historical, bridge and test years. These are combined for the purposes of harmonizing rates.
Transformer Allowance	This is the actual and weather normalized transformer allowance quantities for the historical, bridge and test years. These are combined for the purposes of harmonizing rates.
Smart Meter Adders	These are the Board Approved smart meter rate adders. This worksheet weights the number of metered customer per class with the respective smart meter recovery and calculates a weighted rate per metered customer for the combined service territories.

Loss Factor	These are the Board Approved and forecasted loss factors. The loss factors remain unique to the service territory in this Application.
Monthly Service Charge Analysis	This worksheet compares the rate design monthly services charges to the floor and ceiling values determined in CNPI – combined Cost Allocation Informational Filing. The worksheet returns a confirmation that the rate design monthly service charge is within the range suggested by the Board.
Regulatory Asset Recovery	These are the regulatory asset rate riders calculated by class for those accounts that CNPI has elected in this Application for disposal. The regulatory asset recoveries remain unique to the service territory.
Cost Allocation Review	The worksheet is used to extrapolate the 2009 base revenue requirement and other distribution revenue allocation to classes on the basis of the combined 2006 Cost Allocation Informational Filing.
Cost Alloc. Revenue Distribution	This worksheet allocates the base revenue requirement to the customer classes to achieve cost allocation to the classes consistent with the Cost Allocation Informational Filing and the Report of the Board, Application of Cost Allocation for Electricity Distributors (EB-2007-0667) dated November 28, 2007. Column L adjusts the Class Revenue to Costs Ratios and Column F adjusts the fixed and variable class ratios.

Dx Rates CA Distribution	This worksheet calculates the 2009 electricity distribution rates on the basis of the class allocation and the fixed and variable splits chosen in the previous tab; Cost Aloc Revenue Distribution.
Other Electricity Charges	This is a listing of Board Approved electricity distribution charges for Retail Transmission, Commodity and Administration. These are used for the bill and rate impact calculations.
Fort Erie Rate Schedule	This tab contains the Board Approved electricity distribution rates from the 2006 EDR, the 2007 IRM, the 2008 IRM, the projected rates using the 2006 EDR allocations and the proposed cost allocation to classes. The tab is intended to allow easy comparison of rates and provides the expected bill rate impact as calculated in the Rate Impact CA Tab discussed in the following.
EOP Rate Schedule	This tab contains the Board Approved electricity distribution rates from the 2006 EDR, the 2007 IRM, the 2008 IRM, the projected rates using the 2006 EDR allocations and the proposed cost allocation to classes. The tab is intended to allow easy comparison of rates and provides the expected bill rate impact as calculated in the Rate Impact CA Tab discussed in the following.
Rate Impact Summary	This worksheet summarizes the rate impacts determined in the previous worksheets.

Rate Impact CA	This worksheet calculates the rate impact of the 2009 electricity distribution rates determined on the basis of proposed distribution of revenues derived from the 2006 Cost Allocation Informational Filing as compared to bills calculated using the Board Approved 2008 electricity distribution rates.
Bill Impact CA	This worksheet calculates the bill impact of the 2009 electricity distribution rates determined on the basis of proposed distribution of revenues derived from the 2006 Cost Allocation Informational Filing as compared to the Board Approved 2008 electricity distribution rates.
Reconciliation	This worksheet reconciles the proposed electricity rates, the forecasted load and customer growth and the base revenue requirement.

Base Revenue Requirement

In this Application, CNPI has determined the harmonized Base Revenue Requirement to be $11,476,276 for 2009 Test Year. This compares to the $9,657,402 Base Revenue Requirement in the 2006 Board Approved 2006 EDR; this change represents an average 3.8% year-over-year increase.

The table provided below details the Base Revenue Requirement derivation from the Service Revenue Requirement, the revenue offsets and the transformer allowance.

CNPI – Fort Erie Base Revenue Requirement		
	2006 Board Approved (Combined) $	2009 Test Year $
Service Revenue Requirement[1]	10,296,073	12,282,994
Less: Revenue Offsets	517,905	710,881
Base Revenue Requirement	9,778,168	11,572,113
Low Voltage Costs to Hydro One	120,767	95,837
Base Revenue Requirement Net of LV	9,657,402	11,476,276
Transformer Ownership Allowance	153,529	119,986
Base Revenue Requirement with Transformer Allowance Add Back	9,810,931	11,596,262

1. Includes Low Voltage Charges from Hydro One

Customer Classes

The following are descriptions of the Rate Classes as approved by the Board as part of CNPI's 2008 Electricity Distribution Rate Application, the 2008 IRM, EB-2008-0839. CNPI – Fort Erie is not proposing any changes to the existing Board Approved customer classes.

Residential

The Residential Class (Regular) refers to a service taking electricity normally at 750 volts or less where the electricity is used for domestic and household purposes in a single family unit. A single family unit being a permanent structure located on a single parcel of land and approved by a civic authority as a dwelling and occupied for that purpose by a single customer.

Residential rates are also applied to apartment buildings with 6 units or less that are bulk metered. Apartment buildings with more than 6 units that are bulk metered are deemed to be General Service.

General Service Less than 50 kW

This classification refers to the supply of electrical energy to single commercial or industrial customer and whose average peak demand is (or is forecasted to be) less than 50 kW. Single commercial or industrial customers are interpreted as a structure or structures on a single parcel of land occupied by one customer. An apartment building with more than 6 units that is bulk metered and has an average peak demand less than 50 kW is deemed to be General Service less than 50 kW. The common area of a separately metered apartment building having a demand less than 50 kW is also deemed to be General Service less than 50 kW.

General Service 50 to 4,999 kW

This classification refers to the supply of electrical energy to single commercial or industrial customer and whose average peak demand is (or is forecasted to be) equal to or greater than 50 kW but less than 5000 kW. Single commercial or industrial customers are interpreted as a structure or structures on a single parcel of land occupied by one customer.

Unmetered Scattered Load

This classification refers to the supply of electrical service to a customer that is deemed to have a constant load over a billing period, normally with minimum electrical consumption and the consumption is unmetered. Energy consumption is based on connected wattage and calculated hours of use. Examples of unmetered scattered load are cable television amplifiers, billboards, area lighting.

Sentinel Lighting

This classification refers to all services required to supply sentinel lighting equipment.

Street Lighting

This classification refers to the supply of electrical service for roadway lighting. Energy consumption is based on connected wattage and calculated hours of use. Customers are usually a Municipality, Region or the Ministry of Transportation.

Transformer Allowance

CNPI provides a transformer allowance credit to customers that provide their own transformation facilities. The current Board Approved rate is $0.60 per kW of billing demand.

CNPI's distribution rates are based on the delivery of electricity at utilization voltage. The cost related to line transformers is recovered in the distribution rates; including those rate changes of customers providing their own transformers.

To compensate those customers who own their own transformers, CNPI applies the transformer ownership credit based on the customer's billing demand.

The Board has current initiative, Rate Design for Recovery of Electricity distribution Costs, EB-2007-0031, that among other things is reviewing the transformer allowance. CNPI is proposing the continuation of the current Board Approved rate of $0.60.

In the Board Approved 2006 EDR, the transformer allowance credit was allocated over all customer classes. In this Application, CNPI is proposing to allocate the transformer allowance credit forecast only to the customer class attributable to the credit; the General Service 50 to 4,999 kW customer class. The transformer credit allowance forecast is intended to compensate the allocation of revenue requirement to proxy full transformation cost allocation.

Low Voltage Rate Adders

There are no Low Voltage charges from Hydro One to CNPI – Fort Erie and consequently there are no Low Voltage Rate Adders in electricity distribution rates for 2009 Test Year.

The Low Voltage charges from Hydro One to CNPI – Eastern Ontario Power have been allocated to the customer classes consistent with the recovery of Retail Transmission Connection revenue. CNPI – Eastern Ontario Power acknowledges that there are currently initiatives before the Board which may impact Low Voltage Charges, CNPI – Eastern Ontario Power will comply with the Board's direction on this matter.

The following table details the calculation of Low Voltage Charges for CNPI – Eastern Ontario Power as determined in Exhibit 9 Tab 1 Schedule 1 of the CNPI – Eastern Ontario Power Application and remains relevant to this section.

Low Voltage charges will be applied only to customer of the Gananoque service territory.

Proposed Low Voltage Rate Adders		
Customer Class	Low Voltage Rate Adder $	UOM
Residential	0.0004	kWh
General Service less than 50 kW	0.0015	kWh
General Service 50 to 4,999 kW	0.1149	kW
Unmetered Scattered Load	0.0015	kWh
Sentinel Lighting	0.0532	kW
Street Lighting	0.0232	kW

Smart Meter Rate Adders

CNPI is not authorized to conduct discretionary smart metering activities and as such is not requesting a change to the current Board Approved Smart Metering Rate Adder per metered customer. In Fort Erie the Adder was $0.27 per metered customer and in Gananoque the Adder was $0.26 per metered customer. The weight average of the two yields an Adder of $0.27 per metered customer. This calculation is detailed in the Rate Design Model.

Retail Transmission Rate

CNPI is not forecasting a change from the current Board Approved Retail Transmission Rates in Fort Erie, CNPI – Fort Erie 2008 IRM (EB-2007-0839) in 2009 Test Year

CNPI is not forecasting a change from the current Board Approved Retail Transmission Rates, CNPI – Eastern Ontario Power 2008 IRM (EB-2007-0839) in 2009 Test Year, except the effect of combining the formerly approved General Service 50 to 4,999 kW Time of Use customer class with the General Service 50 to 4,999 kW customer class.

CNPI acknowledges that there are currently initiatives before the Board which may impact the Provincial Transmission Tariff and ultimately the Retail Transmission Tariffs charged by CNPI – Eastern Ontario Power. CNPI – Eastern Ontario Power will comply with the Board's direction on this matter.

CNPI – Eastern Ontario Power has calculated the Retail Transmission Rates for the combined General Service 50 to 4,999 kW Time of Use customer class with the General Service 50 to 4,999 kW customer class by weighting the existing Board Approved Rates. This weighting is relative to the contributions of the existing General Service 50 to 4,999 kW customer class and the residual customers of the former General Service 50 to 4,999 kW Time of Use customer class to retail transmission revenue recovery.

The Retail Transmission Rates for Connection and Network Charges proposed in this Application are shown in the table below. The only exception to the Rates approved by the Board in the 2008 IRM (EB-2007-0846) is the weighting of previously approved rates of the General Service 50 to 4,999 kW customer class and the residual customers of the former General Service 50 to 4,999 kW Time of Use customer class.

Proposed Retail Transmission Rates			
Customer Class	Retail Transmission Rates		UOM
	Connection Charge $	Network Charge $	
Residential	0.0041	0.0043	kWh
General Service less than 50 kW	0.0037	0.0039	kWh
General Service 50 to 4,999 kW	1.5725	1.6231	kW
Unmetered Scattered Load	0.0037	0.0039	kWh
Sentinel Lighting	1.1635	1.1972	kW
Street Lighting	1.1396	1.1911	kW

Other Regulated Commodity Charges

CNPI is not forecasting a change from the current Board Approved rates, CNPI – Fort Erie 2008 IRM (EB-2007-0839) and CNPI – Gananoque (EB-2007-0846) for the Wholesale Market Service Rate, the Rural Rate Protection Charge and the Standard Supply Service – Administrative Charge in 2009 Test Year.

Rate Rider for Storm Damage Cost Recovery

In the Board's Decision with Reasons in the matter of applications by CNPI – Fort Erie, CNPI – Port Colborne, Peterborough Distribution Inc, and Lakeland Power Distribution Ltd. (EB-2007-0514, EB-2007-0595, EB-2007-0571, EB-2007-0551) dated July 31, 2007, CNPI – Fort Erie received Board approval for extraordinary event storm damage cost recovery. The Board's Decision with Reasons approves rate riders on both the Monthly Service Charge and on the Volumetric Charge to be effective from September 1, 2007 to August 31, 2009. These rate riders were approved again in the CNPI – Fort Erie 2008 IRM, EB-2007-0839. CNPI will maintain these Board Approved rate riders in its request for distribution rates effective May 1, 2009 for the Fort Erie Service territory. These rate riders will remain effective until August 31, 2009.

Commodity Pricing

CNPI has used consistent commodity pricing for comparison of May 2008 and May 2009 bill and rate impacts. CNPI has used $0.053 per kWh for the first tier price and $0.062 per kWh for the second tier price.

Allocation of Base Revenue Requirement to Customer Classes

The rate design for the harmonized service territories is based on a combined Cost Allocation Informational Filing for Fort Erie and Gananoque.

In this Application, CNPI is proposing to allocate the Base Revenue Requirement to customer Classes in a manner that will move each customer class's revenue-to-cost ratio closer to unity while respecting class rate impacts and the Board's guidelines. The fixed and variable proportions of the class revenue requirement have been modified, where necessary, to keep the class monthly service charge consistent with the recent 2007IRM and 2008 IRM Board Approved rates and to respect the Board's guidelines related to the level of the fixed monthly service charge. For certain customer classes there is a significant variance between the monthly service charges approved in the 2008 IRM for Fort Erie and Gananoque. This is discussed in the detailed description for each customer class which follows in this Exhibit.

Determination of the Appropriate Share of the 2009 Revenue Requirement by Class

In the 2006 Board Approved EDR, the appropriate amount of the revenue requirement recovered from each of the customer classes was determined to be in the same proportions as costs were allocated on average in 2002 to 2004. This same allocation to classes underpins the current electricity distribution rates approved in CNPI – Fort Erie and CNPI – Eastern Ontario Power

On January 18, 2007, CNPI – Fort Erie and eastern Ontario Power submitted its Cost Allocation Informational Filing (EB-2007-0344) to the Board, discussed more fully in Exhibit 8 (Cost Allocation) of this Application and CNPI – Eastern Ontario Power's Application. Among other indicators, this Cost Allocation Informational Filing indicated the appropriate proportion of total revenue requirement to be recovered from each customer class and, based on the 2006 Board Approved EDR, determined the current revenue-to-cost ratio for each class. The Cost Allocation Informational Filing also provided a range of costs that were appropriate for the Monthly Service Charge for each of the customer classes.

In the Report of the Board, Application of Cost Allocation for Electricity Distributors (EB-2007-0667) dated November 28, 2007, the Board provided guidance ("Board guidelines") on the appropriate revenue-to-cost ratio for each class. In this Application, CNPI is proposing to re-distribute the proportions of revenue requirement assigned to each of its customer classes with a goal of achieving revenue-to-cost ratios consistent with the Board guidelines, while not moving any class ratio further from a unity revenue-to-cost ratio. CNPI has taken a fair and reasonable approach in its rate design to achieve the eventual goal of moving its class revenue-to-cost ratios to unity. CNPI has considered the regulatory principle of rate stability and predictability. While allocating the revenue requirement to the appropriate customer classes is a matter of fairness, it must be balanced with the principle of rate stability and predictability for the customer. CNPI is proposing a gradual movement toward unity revenue-to-cost ratios, while respecting the Board's guidelines and the total bill impacts stemming from this rate design.

In certain instances, for example the General Service 50 to 4,999 kW, there exists a wide gap in the monthly service charges currently in effect for CNPI – Fort Erie and CNPI – Eastern Ontario Power, CNPI has chosen a harmonized rate that exerts the least rate pressure on the customers in either service territory.

As a result of shifting the proportions of revenue requirement between classes to achieve a given revenue-to-cost ratio, CNPI has had to modify existing allocations between the fixed and variable components of the distribution charge to align the proposed Monthly Service Charges to minimize rate impacts.

The following is a class specific discussion of the methodology and rationale utilized by CNPI to allocate the Base Revenue Requirement to the customer classes.

Residential

Board Approved Distribution Rates, Effective May 1, 2008				
Fort Erie				
Monthly Service Charge	$	20.06		
Volumetric Rate	$/kWh	0.0072		
Revenue-to-Cost Ratio(1)	82.69%			
Gananoque				
Monthly Service Charge	$	16.32		
Volumetric Rate	$/kWh	0.0073		
Revenue-to-Cost Ratio(1)	73.02%			
2009 Harmonized Electricity Distribution Rate Design				
Fort Erie				
			Total Bill Impact	Revenue-to-Cost Ratio
Monthly Service Charge	$	17.96	4.9%	82.88%
Volumetric Rate	$/kWh	0.015		
Gananoque				
			Total Bill Impact	Revenue-to-Cost Ratio
Monthly Service Charge	$	17.96	9.4%	82.88%
Volumetric Rate(2)	$/kWh	0.0154		

Note (1) Revenue-to-Cost ratio determined by the CNPI Cost Allocation Informational Filing.
Note (2) Includes the Low Voltage Adder.

The CNPI – Fort Erie Cost Allocation Informational Filing determined that the Residential Class had a Revenue-to-Cost Ratio of 82.69% and the CNPI – Eastern Ontario Power Cost Allocation Informational Filing determined that the Residential Class had a Revenue-to-Cost Ratio of 73.02%. The Board's guidelines suggest that the Revenue-to-Cost Ratio for the Residential Class should be in the range of 85% to 115%. CNPI has proposed to gradually move toward the 100% Revenue-to-Cost Ratio. To fairly implement the changes to all customer classes, CNPI proposes an 82.88% Revenue-to-Cost Ratio which results in a 4.9% bill impact in Fort Erie and 9.6% bill impact for Gananoque for the 1000 kWh residential customer. It was necessary to stay below the 85% revenue-to-cost ratio threshold in order to limit bill impact in Gananoque. A more comprehensive listing of bill and rate impacts can be seen in Exhibit 9, Tab 1, Schedule 5 (Bill Impacts).

This establishes the proportion of Base Revenue Requirement allocated to the Residential Class at 51%. The monthly service charge has been designed to minimize rate impacts. In its guidelines, the Board has suggested lower and upper bounds for the Monthly Service Charge; this proposal respects those boundaries.

General Service Less Than 50 kW

Board Approved Distribution Rates, Effective May 1, 2008				
Fort Erie				
Monthly Service Charge	$	17.56		
Volumetric Rate	$/kWh	0.0222		
Revenue-to-Cost Ratio(1)	129.81%			
Gananoque				
Monthly Service Charge	$	32.87		
Volumetric Rate	$/kWh	0.0154		
Revenue-to-Cost Ratio(1)	142.48%			
2009 Harmonized Electricity Distribution Rate Design				
Fort Erie				
			Total Bill Impact	Revenue-to-Cost Ratio
Monthly Service Charge	$	21.34	1.7%	120.0%
Volumetric Rate	$/kWh	0.0228		
Gananoque				
			Total Bill Impact	Revenue-to-Cost Ratio
Monthly Service Charge	$	21.34	2.9%	120.0%
Volumetric Rate(2)	$/kWh	0.0243		

Note (1) Revenue-to-Cost ratio determined by the CNPI Cost Allocation Informational Filing.

Note (2) Includes the Low Voltage Adder.

The CNPI – Fort Erie Cost Allocation Informational Filing determined that the Residential Class had a Revenue-to-Cost Ratio of 129.81% and the CNPI – Eastern Ontario Power Cost Allocation Informational Filing determined that the Residential Class had a Revenue-to-Cost Ratio of 142.48%. The Board's guidelines suggest that the Revenue-to-Cost Ratio for the Residential Class should be in the range of 80% to 120%. CNPI has proposed to gradually move toward the 100% Revenue-to-Cost Ratio. To fairly implement the changes to all customer classes, CNPI proposes an 120% Revenue-to-Cost Ratio which results in a 1.7% bill impact in Fort Erie and 2.9% bill impact for Gananoque for the 2000 kWh General Service less than 50 kW customer. The selection of the 120% revenue-to-cost ratio for this class is a measured amount to reach the threshold of 120% while not exerting undue rate pressures on the other customer classes. A more comprehensive listing of bill and rate impacts can be seen in Exhibit 9, Tab 1, Schedule 5 (Bill Impacts).

This establishes the proportion of Base Revenue Requirement allocated to the General Service less than 50 kW Class at 13.8%. The monthly service charge has been designed to minimize rate impacts. In its guidelines, the Board has suggested lower and upper bounds for the Monthly Service Charge; this proposal respects those boundaries.

General Service 50 to 4,999 kW

Board Approved Distribution Rates, Effective May 1, 2008				
Fort Erie				
Monthly Service Charge	$	116.52		
Volumetric Rate	$/kW	7.2398		
Revenue-to-Cost Ratio[1]	151.44%			
Gananoque				
Monthly Service Charge	$	764.96		
Volumetric Rate	$/kW	3.5235		
Revenue-to-Cost Ratio[1]	158.23%			
2009 Harmonized Electricity Distribution Rate Design				
Fort Erie				
			Total Bill Impact	Revenue-to-Cost Ratio
Monthly Service Charge	$	148.11	2.0%	152.66%
Volumetric Rate	$/kW	8.062		
Gananoque				
			Total Bill Impact	Revenue-to-Cost Ratio
Monthly Service Charge	$	148.11	1.2%	152.66%
Volumetric Rate[2]	$/kW	8.1769		

Note (1) Revenue-to-Cost ratio determined by the CNPI Cost Allocation Informational Filing.
Note (2) Includes the Low Voltage Adder.

The CNPI – Fort Erie Cost Allocation Informational Filing determined that the Residential Class had a Revenue-to-Cost Ratio of 151.44% and the CNPI – Eastern Ontario Power Cost Allocation Informational Filing determined that the Residential Class had a Revenue-to-Cost Ratio of 158.23%. The Board's guidelines suggest that the Revenue-to-Cost Ratio for the Residential Class should be in the range of 80% to 180%. CNPI has proposed to gradually move toward the 100% Revenue-to-Cost Ratio. To fairly implement the changes to all customer classes, CNPI proposes an 152.66% Revenue-to-Cost Ratio which results in a 2.0% bill impact in Fort Erie and 1.2% bill impact for Gananoque for the for the average General Service 50 to 4,999 kW customer. The selection of the 152.66% revenue-to-cost ratio for this class is a measured amount to reduce the allocation to this customer class while not exerting undue rate pressures on the other customer classes. A more comprehensive listing of bill and rate impacts can be seen in Exhibit 9, Tab 1, Schedule 5 (Bill Impacts).

This establishes the proportion of Base Revenue Requirement allocated to the General Service 50 to 4,999 kW Class at 33.7%. The monthly service charge has been designed to minimize rate impacts. In its guidelines, the Board has suggested lower and upper bounds for the Monthly Service Charge; this proposal respects those boundaries.

Unmetered Scattered Load

Board Approved Distribution Rates, Effective May 1, 2008				
Fort Erie				
Monthly Service Charge	$	8.56		
Volumetric Rate	$/kWh	0.0220		
Revenue-to-Cost Ratio(1)	56.76%			
Gananoque				
Monthly Service Charge	$	32.87		
Volumetric Rate	$/kWh	0.0154		
Revenue-to-Cost Ratio(1)	65.94%			
2009 Harmonized Electricity Distribution Rate Design				
Fort Erie				
			Total Bill Impact	Revenue-to-Cost Ratio
Monthly Service Charge	$	36.39	33.7%	44.69%
Volumetric Rate	$/kWh	0.0217		
Gananoque				
			Total Bill Impact	Revenue-to-Cost Ratio
Monthly Service Charge	$	36.39	9.4%	44.69%
Volumetric Rate(2)	$/kWh	0.0232		

Note (1) Revenue-to-Cost ratio determined by the CNPI Cost Allocation Informational Filing.
Note (2) Includes the Low Voltage Adder.

The CNPI – Fort Erie Cost Allocation Informational Filing determined that the Residential Class had a Revenue-to-Cost Ratio of 56.76% and the CNPI – Eastern Ontario Power Cost Allocation Informational Filing determined that the Residential Class had a Revenue-to-Cost Ratio of 65.94%. The Board's guidelines suggest that the Revenue-to-Cost Ratio for the

Residential Class should be in the range of 80% to 120%. CNPI has proposed to gradually move toward the 100% Revenue-to-Cost Ratio. To fairly implement the changes to all customer classes, CNPI proposes a 44.69% Revenue-to-Cost Ratio which results in a 33.7% bill impact in Fort Erie and 9.4% bill impact for Gananoque for the 750 kWh Unmetered Scattered Load Class customer. The selection of the 44.69% revenue-to-cost ratio for this class is a measured amount to not exert undue rate pressures on the customer class. A more comprehensive listing of bill and rate impacts can be seen in Exhibit 9, Tab 1, Schedule 5 (Bill Impacts).

This establishes the proportion of Base Revenue Requirement allocated to the General Service less than 50 kW Class at 0.19%. The monthly service charge has been designed to minimize rate impacts. In its guidelines, the Board has suggested lower and upper bounds for the Monthly Service Charge; this proposal is slightly above the upper bound but is in line with existing rates in Gananoque.

Currently, in CNPI – Fort Erie the Unmetered Scatted Load customers are billed on a per connection basis where as at CNPI – Eastern Ontario Power the Unmetered Scatted Load customers are billed on a per customer basis with estimated consumption aggregated on a single bill. Effective May 1, 2009, upon the Board's approval of this application, CNPI – Fort Erie will implement billing to the Unmetered Scattered Load class on a per customer basis.

Notwithstanding the rate impacts calculated by comparing the May 1, 2009 proposed rate structure to the May 1, 2008 rate structure the effective total bill impact will be significantly less. In the case of the customer with the most connections, 80 connections, with a totalized consumption of approximately 24,000 kWh the impact is approximately -19%. Customer with two or less connections will still see rate impacts greater than the 10% threshold that CNPI has established for implementation of rate impact mitigation. CNPI will work with these customers to determine a suitable solution.

Sentinel Lighting

Board Approved Distribution Rates, Effective May 1, 2008				
Fort Erie				
Monthly Service Charge	$	1.97		
Volumetric Rate	$/kW	1.9700		
Revenue-to-Cost Ratio(1)	37.35%			
Gananoque				
Monthly Service Charge	$	1.78		
Volumetric Rate	$/kW	2.6201		
Revenue-to-Cost Ratio(1)	31.77%			
2009 Harmonized Electricity Distribution Rate Design				
Fort Erie				
			Total Bill Impact	Revenue-to-Cost Ratio
Monthly Service Charge	$	2.94	9.7%	54.61%
Volumetric Rate	$/kW	3.329		
Gananoque				
			Total Bill Impact	Revenue-to-Cost Ratio
Monthly Service Charge	$	2.94	8.4%	54.61%
Volumetric Rate(2)	$/kW	3.3822		

Note (1) Revenue-to-Cost ratio determined by the CNPI Cost Allocation Informational Filing.

Note (2) Includes the Low Voltage Adder.

The CNPI – Fort Erie Cost Allocation Informational Filing determined that the Residential Class had a Revenue-to-Cost Ratio of 37.35% and the CNPI – Eastern Ontario Power Cost Allocation Informational Filing determined that the Residential Class had a Revenue-to-Cost Ratio of 31.77%. The Board's guidelines suggest that the Revenue-to-Cost Ratio for the Residential Class should be in the range of 70% to 120%. CNPI has proposed to gradually move toward the 100% Revenue-to-Cost Ratio. To fairly implement the changes to all customer classes, CNPI proposes an 54.61% Revenue-to-Cost Ratio which results in a 9.7% bill impact in Fort Erie and 8.4% bill impact for Gananoque for the for the average Sentinel Lighting Class customer. The selection of the 54.61% revenue-to-cost ratio for this class is a measured amount to not exert undue rate pressures on the customer class. A more comprehensive listing of bill and rate impacts can be seen in Exhibit 9, Tab 1, Schedule 5 (Bill Impacts).

This establishes the proportion of Base Revenue Requirement allocated to the Sentinel Lighting Class at 0.4%. The monthly service charge has been designed to minimize rate impacts. In its guidelines, the Board has suggested lower and upper bounds for the Monthly Service Charge; this proposal respects those boundaries.

Street Lighting

Board Approved Distribution Rates, Effective May 1, 2008				
Fort Erie				
Monthly Service Charge	$	1.31		
Volumetric Rate	$/kW	1.5823		
Revenue-to-Cost Ratio(1)	19.16%			
Gananoque				
Monthly Service Charge	$	1.77		
Volumetric Rate	$/kW	2.4164		
Revenue-to-Cost Ratio(1)	27.64%			
2009 Harmonized Electricity Distribution Rate Design				
Fort Erie				
			Total Bill Impact	Revenue-to-Cost Ratio
Monthly Service Charge	$	1.69	9.9%	23.91%
Volumetric Rate	$/kW	3.300		
Gananoque				
			Total Bill Impact	Revenue-to-Cost Ratio
Monthly Service Charge	$	1.69	1.6%	23.91%
Volumetric Rate(2)	$/kW	3.3232		

Note (1) Revenue-to-Cost ratio determined by the CNPI Cost Allocation Informational Filing.
Note (2) Includes the Low Voltage Adder.

The CNPI – Fort Erie Cost Allocation Informational Filing determined that the Residential Class had a Revenue-to-Cost Ratio of 19.16% and the CNPI – Eastern Ontario Power Cost Allocation Informational Filing determined that the Residential Class had a Revenue-to-Cost Ratio of 27.64%. The Board's guidelines suggest that the Revenue-to-Cost Ratio for the Residential Class should be in the range of 70% to 120%. CNPI has proposed to gradually move toward the 100% Revenue-to-Cost Ratio. To fairly implement the changes to all customer classes, CNPI proposes an 23.91% Revenue-to-Cost Ratio which results in a

9.9% bill impact in Fort Erie and 1.6% bill impact for Gananoque for the for the average Street Lighting Class customer. The selection of the 23.91% revenue-to-cost ratio for this class is a measured amount to not exert undue rate pressures on the customer class. A more comprehensive listing of bill and rate impacts can be seen in Exhibit 9, Tab 1, Schedule 5 (Bill Impacts).

This establishes the proportion of Base Revenue Requirement allocated to the Street Lighting Class at 0.89%. The monthly service charge has been designed to minimize rate impacts. In its guidelines, the Board has suggested lower and upper bounds for the Monthly Service Charge; this proposal respects those boundaries.

Resultant Cost Allocation

The following table summarizes the proposed allocation of Base Revenue Requirement to the customer classes and shows the resulting over or under contribution by customer class.

Proposed Allocation of Base Revenue Requirement			
Customer Class	100% Allocation $	Proposed Allocation $	Over/(Under) Contribution $
Residential	7,061,859	5,852,901	(1,208,958)
General Service less than 50 kW	1,318,280	1,581,936	263,656
General Service 50 to 4,999 kW	2,536,171	3,871,636	1,335,466
Unmetered Scattered Load	48,689	21,759	(26,930)
Sentinel Lighting	84,053	45,905	(38,148)
Street Lighting	427,224	102,139	(325,086)

Full Allocation

The resultant impacts of 100% Revenue-to-Cost Ratio is shown in the table below.

100% Allocation of Base Revenue Requirement to Classes		
Customer Class	Total Bill Impact	
Residential	10.1%	14.6%
General Service less than 50 kW	-3.7%	-2.3%
General Service 50 to 4,999 kW	-5.6%	-7.1%
Unmetered Scattered Load	113.9%	72.8%
Sentinel Lighting	33.3%	29.4%
Street Lighting	120.4%	85.3%

Summary

In its rate design, CNPI has strived to move the customer class cost allocations to a value that yields a class revenue-to-cost ratio, as determined by the Cost Allocation Informational Filing, closer to unity. CNPI has considered and respected the Board's guidelines related to a reasonable bandwidth for each customer class's individual revenue-to-cost ratio. In these cases where CNPI has designed a class revenue-to-cost ratio that is outside of the range suggested by the Board's guidelines, it has done so only as a rate mitigation measure.

In moving the respective customer class revenue-to-cost ratio toward a unity value, CNPI has attempted to balance the individual customer class revenue-to-cost yield against a sense of fairness and rate stability and predictability.

APPENDIX A

Harmonized Rate Design Model

CANADIAN NIAGARA POWER INC.

A FORTIS ONTARIO Company

Fort Erie & Gananoque Service Territories
Harmonized Rate Design Model
2009 Electricity Distribution Rate Application
EB - 2008 - 0223

Harmonized
Revenue Requirement for 2009 Test Year

	2006 EDR	2009 Test Year
Service Revenue Requirement (Including Low Voltage Charge)	10,296,073	12,282,994
Less:		
Revenue Offsets		
Specific Service Charges	442,265	50,000
Late Payment Charges	71,822	234,000
Other Distribution revenue	81,187	391,881
Other Income and deductions	(77,369)	35,000
Total Revenue Offsets	517,905	710,881
Base Revenue Requirements	9,778,168	11,572,113
Low Voltage Costs to Hydro One	120,767	95,837
Base Revenue Requirement Net of LV Costs	9,657,402	11,476,276
Transformation Credit (Annualized Amount)[1]	153,529	119,986
Base Revenue Requirement with Transformation Credit Add Back	9,810,931	11,596,262

1. The transformer allowance is annualized for the Fort Erie portion and year end for Gananoque due to the sudden loss of load at the beginning of the year.

Harmonized Load and Customer Forecast Information

	Data From 2006 EDR Board Approved Model				From Energy Sales			Normalized Forecast	
	2002	**2003**	**2004**	**2006 EDR**	**2005**	**2006 Year End**	**2007 Year End**	**2008 Bridge Year**	**2009 Test Year**
Residential									
Number of Customers	16,436	16,542	16,789	16,789	16,915	17,018	17,173	17,303	17,434
Kilowatt-hours	144,224,723	138,907,394	136,365,727	141,540,950	144,027,569	141,492,704	143,862,348	143,838,627	144,908,264
GS < 50 kW									
Number of Customers	1,468	1,460	1,548	1,548	1,569	1,580	1,579	1,590	1,601
Kilowatt-hours	56,849,241	55,989,487	51,795,448	57,038,476	54,834,982	52,068,744	51,468,696	51,437,227	51,795,147
GS > 50 kW									
Number of Customers	157	164	167	167	174	168	176	178	182
Kilowatt-hours	167,011,972	203,229,761	180,149,026	188,076,527	182,659,568	164,724,551	163,912,155	165,838,312	166,344,327
Kilowatts	405,232	493,178	447,922	460,009	486,774	421,487	450,450	453,640	457,378
Unmetered Scattered Load									
Number of Customers	20	20	20	20	20	28	28	28	28
Kilowatt-hours	338,832	341,288	342,516	318,026	323,970	423,415	429,674	435,552	444,370
Sentinel Light									
Number of Connections	920	920	920	920	943	1,044	1,047	1,050	1,052
Kilowatt-hours	936,490	930,198	775,938	880,875	930,074	862,837	873,562	876,220	877,992
Kilowatts	2,712	2,694	2,173	2,526	2,780	2,540	2,651	2,659	2,664
Street Light									
Number of Connections	3,586	3,586	3,586	3,586	3,607	3,629	3,654	3,674	3,694
Kilowatt-hours	2,591,188	2,352,157	2,471,796	2,471,714	3,026,599	3,166,953	2,735,755	2,751,108	2,766,461
Kilowatts	7,206	6,537	6,923	6,889	8,469	8,233	8,287	8,334	8,380
Totals									
Number of Connections	22,587	22,692	23,030	23,030	23,228	23,467	23,657	23,823	23,991
Kilowatt-hours	371,952,446	401,750,285	371,900,451	390,326,568	385,802,762	362,739,204	363,282,190	365,177,046	367,136,561
Kilowatts	415,150	502,409	457,018	469,425	498,023	432,260	461,388	464,633	468,422

Harmonization Transformation Allowance Forecast Information

Classification	2006 EDR		From Energy Sales Data						Forecasted			
	2006 EDR		2005 Actual		2006 Actual		2007 Actual		2008 Bridge Year		2009 Test Year	
	kW	$	kW	$	kW	$	kW	$	kW	$	kW	$
General Service 50 to 4,999 kW	255,612	153,529	247,182	148,309	213,104	127,862	209,196	125,518	205,932	123,559	201,886	121,131

Transformation Allowance Rate	$/kW	0.60

Harmonized
Weighted Average
Smart Meter Adder

Customer Class	Smart Meter Adder
Residential	0.27
General Service Less Than 50 kW	0.27
General Service 50 to 4,999 kW	0.27

CNPI - Fort Erie

Loss Factors

Description	2006 EDR Board Approved	2009 EDR Proposed
Supply Facility Loss Factor	1.0045	1.0033
Distribution Loss Factors		
Secondary Metered Customer < 5,000 kW	1.0432	1.0357
Primary Metered Customer < 5,000 kW	1.0328	1.0259
Total Loss Factors		
Secondary Metered Customer < 5,000 kW	1.0479	1.0391
Primary Metered Customer < 5,000 kW	1.0374	1.0287

CNPI - Eastern Ontario Power

Loss Factors

Description	2006 EDR Board Approved	2009 EDR Proposed
Supply Facility Loss Factor	1.0340	1.0272
Distribution Loss Factors		
Secondary Metered Customer < 5,000 kW	1.0363	1.0438
Primary Metered Customer < 5,000 kW	1.0259	1.0336
Total Loss Factors		
Secondary Metered Customer < 5,000 kW	1.0715	1.0719
Primary Metered Customer < 5,000 kW	1.0608	1.0612

Harmonized Rates
Monthly Service Charge Analysis

Customer Class	2009 Proposed	Lower Bound from Cost Allocation Filing	Upper Bound from Cost Allocation Filing	120 % of Upper Bound	Is the 2009 Proposed Higher than the Lower Boundary?	Is the 2009 Proposed Lower than the Upper Boundary?
Residential	17.96	3.81	18.17	21.80	YES	YES
General Service Less Than 50 kW	21.34	7.52	28.57	34.28	YES	YES
General Service 50 to 4,999 kW	148.11	46.31	129.61	155.53	YES	YES
Unmetered Scattered Load	36.39	8.62	29.66	35.59	YES	NO
Sentinel Lighting	2.94	(0.16)	6.58	7.90	YES	YES
Street Lighting	1.69	(0.16)	12.05	14.46	YES	YES

CNPI - Eastern Ontario Power
Allocation of Low Votage Charges from Hydro One to the Customer Classes

Low Voltage Costs to Hydro One $ 95,837

Customer Classification	Retail Transmission		2006 EDR	2009 EDR	Volumetric Distribution Rate	
	per kWh	per kW	Allocation	Allocation	per kWh	per kW
Residential	0.0041		49.16%	47,113	0.0004	
General Service Less Than 50 kW	0.0037		21.68%	20,773	0.0015	
General Service 50 to 4,999 kW		1.5725	28.95%	27,747		0.1149
Unmetered Scattered Load	0.0037			-	0.0015	
Sentinel Lighting		1.1635	0.05%	51		0.0532
Street Lighting		1.1396	0.16%	154		0.0232
			100%	$ 95,837		

CNPI - Fort Erie
Regulatory Asset Recovery

Customer Class	Rate Rider per kWh	Rate Rider per kW
Residential	0.0002	
General Service Less Than 50 kW	0.0001	
General Service 50 to 4,999 kW		0.0391
Unmetered Scattered Load	0.0003	
Sentinel Lighting		0.0574
Street Lighting		0.0445

CNPI - Eastern Ontario Power
Regulatory Asset Recovery

Customer Class	Rate Rider per kWh	Rate Rider per kW
Residential	0.0002	
General Service Less Than 50 kW	0.0002	
General Service 50 to 4,999 kW		0.0656
Unmetered Scattered Load	0.0003	
Sentinel Lighting		0.0727
Street Lighting		0.0687

Harmonized
Allocation of the 2009 Revenue Requirement on the Basis of the Cost Allocation Informational Filing

Customer Classes	Cost Allocation - Revenue Requirement	Revenue Requirement Allocation Percentage	Cost Allocation Miscellaneous Requirement	Miscellaneous Revenue Allocation Percentage	2009 Service Revenue Requirement Allocation[1]	2009 Miscellaneous Revenue Offset	2009 Base Revenue Requirement Calculation	Low Voltage Allocation	2009 Base Revenue Requirement Less Low Voltage	2009 Base Revenue Allocation per Class	Transformer Allowance Allocation	2009 Base Revenue per Class with Transformer Allocation	2009 Base Revenue with Transformer Allowance Allocation
Residential	6,428,230	62.24%	381,047	73.57%	7,584,889	523,030	7,061,859	n/a	7,061,859	61.53%		7,061,859	60.90%
GS <50 kW	1,204,782	11.66%	75,246	14.53%	1,421,564	103,284	1,318,280	n/a	1,318,280	11.49%		1,318,280	11.37%
GS >50 kW	2,205,668	21.35%	48,355	9.34%	2,602,543	66,373	2,536,171	n/a	2,536,171	22.10%	119,986	2,656,157	22.91%
Street Lights	362,988	3.51%	785	0.15%	428,302	1,078	427,224	n/a	427,224	3.72%		427,224	3.68%
Sentinel Lights	71,601	0.69%	314	0.06%	84,484	431	84,053	n/a	84,053	0.73%		84,053	0.72%
Unmetered Scattered Load	55,406	0.54%	12,157	2.35%	65,375	16,687	48,689	n/a	48,689	0.42%		48,689	0.42%
	10,328,675	**100%**	**517,904**	**100%**	**12,187,157**	**710,881**	**11,476,276**		**11,476,276**	**100%**	**111,096**	**11,596,262**	**100%**

1. Low Voltage has been remove for later allocation since it applies to Gananoque customers only.

Harmonized
Determination of the 2009 EDR Revenue to Cost Ratios

Customer Classes	Allowance for Proposed: Adjusted Allocation to Variable Component	Adjusted Allocation to Fixed Component	Revenue at 100% Rev/Cost Ratio (less Transformer Allowance)	Allocation of Revenue at 100% Rev/Cost Ratio (less Transformer Allowance)	Proposed Proportion of Revenue	Base Revenue Requirement @ Proposed Proportions	Over /(Under) Contributing	Proposed Revenue/Cost Ratio	Revenue/Cost Ratio from the 2006 Cost Allocation
Residential	37.00%	63.00%	7,061,859	61.53%	51.000%	5,852,901	(1,208,958)	**82.88%**	**80.52%**
GS <50 kW	74.50%	25.50%	1,318,280	11.49%	13.784%	1,581,936	263,656	**120.00%**	**133.51%**
GS >50 kW	92.00%	8.00%	2,536,171	22.10%	33.736%	3,871,636	1,335,466	**152.66%**	**154.80%**
Street Lights	27.00%	73.00%	427,224	3.72%	0.890%	102,139	(325,086)	**23.91%**	**19.51%**
Sentinel Lights	19.30%	80.70%	84,053	0.73%	0.400%	45,905	(38,148)	**54.61%**	**37.46%**
Unmetered Scattered Load	43.80%	56.20%	48,689	0.42%	0.1896%	21,759	(26,930)	**44.69%**	**57.76%**
			11,476,276	**100.00%**	**100.00%**	**11,476,276**	**0**		

Harmonized

Rates - Base Revenue Requirement - Allocated on the Cost Allocation Informational Filing Distribution of Revenues

	Number of Customers (Connections)	KWh	kW			Base Revenue Proposed Allocation		Base Rates Revenue Requirement divided by the consumption for the Test Year				
	2009	2009	2009	Base Revenue Requirement @ Proposed Proportions	Transformer Allowance Allocation	Variable Component	Fixed Component	Volumetric Rate Type	Rate per kWh	Rate per kW	Fixed Service Charge	With Smart Meter Adder
Class												
Residential	17,369	144,373,446		5,852,901		2,165,573	3,687,327	kWh	0.0150		17.69	17.96
General Service Less Than 50 kW	1,596	51,616,187		1,581,936		1,178,542	403,394	kWh	0.0228		21.07	21.34
General Service 50 to 4,999 kW	180	166,091,320	455,509	3,871,636	119,986	3,672,293	319,330	kW		8.0620	147.84	148.11
Unmetered Scattered Load	28	439,961		21,759		9,530	12,229	kWh	0.0217		36.39	36.39
Sentinel Lighting	1,051	877,106	2,661	45,905		8,860	37,045	kW		3.3290	2.94	2.94
Street Lighting	3,684	2,758,784	8,357	102,139		27,577	74,561	kW		3.3000	1.69	1.69
Totals	23,907	366,156,804	466,527	11,476,276	119,986	7,062,376	4,533,886					

CNPI - Fort Erie
Other Electricity Charges - Board Approved

Class	Retail Transmission Rate: Connection Charge	Unit	Retail Transmission Rate: Network Charge	Unit	Commodity Charges - $/kWh: Wholesale Market Service	Rural Rate Protection	Debt Retirement	Cost of Power 1st Block	Cost of Power Balance	Fees: Administration Fee
Residential	0.0045	kWh	0.0044	kWh	0.0052	0.001	0	0.053	0.062	0.25
General Service Less Than 50 kW	0.0040	kWh	0.0040	kWh	0.0052	0.001	0	0.053	0.062	0.25
General Service 50 to 4,999 kW	1.5973	kW	1.6442	kW	0.0052	0.001	0	0.053	0.062	0.25
Unmetered Scattered Load	0.0040	kWh	0.0040	kWh	0.0052	0.001	0	0.053	0.062	0.25
Sentinel Lighting	1.2607	kW	1.3124	kW	0.0052	0.001	0	0.053	0.062	0.25
Street Lighting	1.2348	kW	1.2400	kW	0.0052	0.001	0	0.053	0.062	0.25

CNPI - Eastern Ontario Power
Other Electricity Charges - Board Approved

Class	Retail Transmission Rate: Connection Charge	Unit	Retail Transmission Rate: Network Charge	Unit	Commodity Charges - $/kWh: Wholesale Market Service	Rural Rate Protection	Debt Retirement	Cost of Power 1st Block	Cost of Power Balance	Fees: Administration Fee
Residential	0.0041	kWh	0.0043	kWh	0.0052	0.001	0.0051	0.053	0.062	0.25
General Service Less Than 50 kW	0.0037	kWh	0.0039	kWh	0.0052	0.001	0.0051	0.053	0.062	0.25
General Service 50 to 4,999 kW	1.5725	kW	1.6231	kW	0.0052	0.001	0.0051	0.053	0.062	0.25
Unmetered Scattered Load	0.0037	kWh	0.0039	kWh	0.0052	0.001	0.0051	0.053	0.062	0.25
Sentinel Lighting	1.1635	kW	1.1972	kW	0.0052	0.001	0.0051	0.053	0.062	0.25
Street Lighting	1.1396	kW	1.1911	kW	0.0052	0.001	0.0051	0.053	0.062	0.25

The Retail Transmission Rate for the General Service 50 to 4,999 has been prorated based on the portion of load absorbed from the previous General

Canadian Niagara Power Inc. - Fort Erie
TARIFF OF RATES AND CHARGES

		May 1, 2006 Board Approved	May 1, 2007 Board Approved	Sept. 1, 2007 Board Approved	May 1, 2008 Board Approved	May 1, 2009 2006 CA Allocations	Bill Impact CA Allocations
Residential							4.9%
Service Charge	$	19.9	19.94	19.94	20.06	17.96	
Service Charge Rate Rider for Storm Damage Cost Recovery - effective until August 31, 2009	$			2.11	2.11	2.11	
Distribution Volumetric Rate	$/kWh	0.0072	0.0072	0.0072	0.0072	0.015	
Distribution Volumetric Rate Rider for Storm Damage Cost Recovery - effective until August 31, 2009	$/kWh			0.0008	0.0008	0.0008	
Rate Rider 1 (if applicable)					0		
Rate Rider 2 (if applicable)					0		
Regulatory Asset Recovery	$/kWh	0.0043	0.0043	0.0043	0	0.0002	
Retail Transmission Rate – Network Service Rate	$/kWh	0.0054	0.0054	0.0054	0.0044	0.0044	
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0047	0.0047	0.0047	0.0045	0.0045	
Retail Transmission Rate – Network Service Rate (if applicable)	$/kWh				0		
Retail Transmission Rate – Line and Transformation Connection Service Rate (if applicable)	$/kWh				0		
Retail Transmission Rate – Network Service Rate (if applicable)	$/kWh				0		
Retail Transmission Rate – Line and Transformation Connection Service Rate (if applicable)	$/kWh				0		
Wholesale Market Service Rate	$/kWh	0.0052	0.0052	0.0052	0.0052	0.0052	
Rural Rate Protection Charge	$/kWh	0.001	0.001	0.001	0.001	0.001	
Standard Supply Service – Administrative Charge (if applicable)	$	0.25	0.25	0.25	0.25	0.25	
General Service Less Than 50 kW							1.7%
Service Charge	$	17.43	17.46	17.46	17.56	21.34	
Service Charge Rate Rider for Storm Damage Cost Recovery - effective until August 31, 2009	$			1.85	1.85	1.85	
Distribution Volumetric Rate	$/kWh	0.0221	0.0221	0.0221	0.0222	0.0228	
Distribution Volumetric Rate Rider for Storm Damage Cost Recovery - effective until August 31, 2009	$/kWh			0.0024	0.0024	0.0024	
Rate Rider 1 (if applicable)					0		
Rate Rider 2 (if applicable)					0		
Regulatory Asset Recovery	$/kWh	-0.0012	-0.0012	-0.0012	0	0.0001	
Retail Transmission Rate – Network Service Rate	$/kWh	0.0049	0.0049	0.0049	0.004	0.004	
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0042	0.0042	0.0042	0.004	0.004	
Retail Transmission Rate – Network Service Rate (if applicable)	$/kWh				0		
Retail Transmission Rate – Line and Transformation Connection Service Rate (if applicable)	$/kWh				0		
Retail Transmission Rate – Network Service Rate (if applicable)	$/kWh				0		
Retail Transmission Rate – Line and Transformation Connection Service Rate (if applicable)	$/kWh				0		
Wholesale Market Service Rate	$/kWh	0.0052	0.0052	0.0052	0.0052	0.0052	
Rural Rate Protection Charge	$/kWh	0.001	0.001	0.001	0.001	0.001	
Standard Supply Service – Administrative Charge (if applicable)	$	0.25	0.25	0.25	0.25	0.25	
General Service 50 to 4,999 kW							2.0%
Service Charge	$	115.61	115.83	115.83	116.52	148.11	
Service Charge Rate Rider for Storm Damage Cost Recovery - effective until August 31, 2009	$			12.42	12.42	12.42	
Distribution Volumetric Rate	$/kW	7.1832	7.1966	7.1966	7.2398	8.062	
Distribution Volumetric Rate Rider for Storm Damage Cost Recovery - effective until August 31, 2009	$/kW			0.7737	0.7737	0.7737	
Rate Rider 1 (if applicable)					0		
Rate Rider 2 (if applicable)					0		
Regulatory Asset Recovery	$/kW	-1.5227	-1.5227	-1.5227	0	0.0391	

Canadian Niagara Power Inc. - Fort Erie
TARIFF OF RATES AND CHARGES

		May 1, 2006 Board Approved	May 1, 2007 Board Approved	Sept. 1, 2007 Board Approved	May 1, 2008 Board Approved	May 1, 2009 2006 CA Allocations	Bill Impact CA Allocations
Retail Transmission Rate – Network Service Rate	$/kW	2.015	2.015	2.015	1.6442	1.6442	
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.6849	1.6849	1.6849	1.5973	1.5973	
Retail Transmission Rate – Network Service Rate (if applicable)	$/kW				0		
Retail Transmission Rate – Line and Transformation Connection Service Rate (if applicable)	$/kW				0		
Retail Transmission Rate – Network Service Rate (if applicable)	$/kW				0		
Retail Transmission Rate – Line and Transformation Connection Service Rate (if applicable)	$/kW				0		
Wholesale Market Service Rate	$/kWh	0.0052	0.0052	0.0052	0.0052	0.0052	
Rural Rate Protection Charge	$/kWh	0.001	0.001	0.001	0.001	0.001	
Standard Supply Service – Administrative Charge (if applicable)	$	0.25	0.25	0.25	0.25	0.25	
Unmetered Scattered Load							33.7%
Service Charge	$	8.49	8.51	8.51	8.56	36.39	
Service Charge Rate Rider for Storm Damage Cost Recovery - effective until August 31, 2009	$			0.91	0.91	0.91	
Distribution Volumetric Rate	$/kWh	0.0219	0.0219	0.0219	0.022	0.0217	
Distribution Volumetric Rate Rider for Storm Damage Cost Recovery - effective until August 31, 2009	$/kWh			0.0024	0.0024	0.0024	
Rate Rider 1 (if applicable)					0		
Rate Rider 2 (if applicable)					0		
Regulatory Asset Recovery	$/kWh	0.0097	0.0097	0.0097	0	0.0003	
Retail Transmission Rate – Network Service Rate	$/kWh	0.0049	0.0049	0.0049	0.004	0.004	
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0042	0.0042	0.0042	0.004	0.004	
Retail Transmission Rate – Network Service Rate (if applicable)	$/kWh				0		
Retail Transmission Rate – Line and Transformation Connection Service Rate (if applicable)	$/kWh				0		
Retail Transmission Rate – Network Service Rate (if applicable)	$/kWh				0		
Retail Transmission Rate – Line and Transformation Connection Service Rate (if applicable)	$/kWh				0		
Wholesale Market Service Rate	$/kWh	0.0052	0.0052	0.0052	0.0052	0.0052	
Rural Rate Protection Charge	$/kWh	0.001	0.001	0.001	0.001	0.001	
Standard Supply Service – Administrative Charge (if applicable)	$	0.25	0.25	0.25	0.25	0.25	
Sentinel Lighting							9.7%
Service Charge	$	1.96	1.96	1.96	1.97	2.94	
Service Charge Rate Rider for Storm Damage Cost Recovery - effective until August 31, 2009	$			0.21	0.21	0.21	
Distribution Volumetric Rate	$/kW	1.9546	1.9583	1.9583	1.97	3.329	
Distribution Volumetric Rate Rider for Storm Damage Cost Recovery - effective until August 31, 2009	$/kW			0.2105	0.2105	0.2105	
Rate Rider 1 (if applicable)					0		
Rate Rider 2 (if applicable)					0		
Regulatory Asset Recovery	$/kW	-2.66	-2.66	-2.66	0	0.0574	
Retail Transmission Rate – Network Service Rate	$/kW	1.6083	1.6083	1.6083	1.3124	1.3124	
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3298	1.3298	1.3298	1.2607	1.2607	
Retail Transmission Rate – Network Service Rate (if applicable)	$/kW				0		
Retail Transmission Rate – Line and Transformation Connection Service Rate (if applicable)	$/kW				0		
Retail Transmission Rate – Network Service Rate (if applicable)	$/kW				0		
Retail Transmission Rate – Line and Transformation Connection Service Rate (if applicable)	$/kW				0		
Wholesale Market Service Rate	$/kWh	0.0052	0.0052	0.0052	0.0052	0.0052	
Rural Rate Protection Charge	$/kWh	0.001	0.001	0.001	0.001	0.001	
Standard Supply Service – Administrative Charge (if applicable)	$	0.25	0.25	0.25	0.25	0.25	

Canadian Niagara Power Inc. - Fort Erie
TARIFF OF RATES AND CHARGES

		May 1, 2006 Board Approved	May 1, 2007 Board Approved	Sept. 1, 2007 Board Approved	May 1, 2008 Board Approved	May 1, 2009 2006 CA Allocations	Bill Impact CA Allocations
Street Lighting							9.9%
Service Charge	$	1.3	1.3	1.3	1.31	1.69	
Service Charge Rate Rider for Storm Damage Cost Recovery - effective until August 31, 2009	$			0.14	0.14	0.14	
Distribution Volumetric Rate	$/kW	1.57	1.5729	1.5729	1.5823	3.3	
Distribution Volumetric Rate Rider for Storm Damage Cost Recovery - effective until August 31, 2009	$/kW			0.1691	0.1691	0.1691	
Rate Rider 1 (if applicable)					0		
Rate Rider 2 (if applicable)					0		
Regulatory Asset Recovery	$/kW	-2.0954	-2.0954	-2.0954	0	0.0445	
Retail Transmission Rate – Network Service Rate	$/kW	1.5196	1.5196	1.5196	1.24	1.24	
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3025	1.3025	1.3025	1.2348	1.2348	
Retail Transmission Rate – Network Service Rate (if applicable)	$/kW				0		
Retail Transmission Rate – Line and Transformation Connection Service Rate (if applicable)	$/kW				0		
Retail Transmission Rate – Network Service Rate (if applicable)	$/kW				0		
Retail Transmission Rate – Line and Transformation Connection Service Rate (if applicable)	$/kW				0		
Wholesale Market Service Rate	$/kWh	0.0052	0.0052	0.0052	0.0052	0.0052	
Rural Rate Protection Charge	$/kWh	0.001	0.001	0.001	0.001	0.001	
Standard Supply Service – Administrative Charge (if applicable)	$	0.25	0.25	0.25	0.25	0.25	
Cost of Power 1st 600	$/kWh				0.053	0.053	
Balance	$/kWh				0.062	0.062	
Loss Factor					1.0479	1.0391	

Canadian Niagara Power Inc. - Eastern Ontario Power
TARIFF OF RATES AND CHARGES

		May 1, 2006 Board Approved	May 1, 2007 Board Approved	May 1, 2008 Board Approved	May 1, 2009 2006 CA Allocations	Bill Impact CA Allocations
Residential						9.5%
Service Charge	$	16.13	16.18	16.32	17.96	
Service Charge Rate Rider for Storm Damage Cost Recovery - effective until August 31, 2009	$			0	0	
Distribution Volumetric Rate	$/kWh	0.0072	0.0072	0.0073	0.0154	
Distribution Volumetric Rate Rider for Storm Damage Cost Recovery - effective until August 31, 2009	$/kWh			0	0	
Rate Rider 1 (if applicable)				0		
Rate Rider 2 (if applicable)				0		
Regulatory Asset Recovery	$/kWh	0.0035	0.0035	0	0.0002	
Retail Transmission Rate – Network Service Rate	$/kWh	0.0052	0.0052	0.0043	0.0043	
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0043	0.0043	0.0041	0.0041	
Retail Transmission Rate – Network Service Rate (if applicable)	$/kWh			0		
Retail Transmission Rate – Line and Transformation Connection Service Rate (if applicable)	$/kWh			0		
Retail Transmission Rate – Network Service Rate (if applicable)	$/kWh			0		
Retail Transmission Rate – Line and Transformation Connection Service Rate (if applicable)	$/kWh			0		
Wholesale Market Service Rate	$/kWh	0.0052	0.0052	0.0052	0.0052	
Rural Rate Protection Charge	$/kWh	0.001	0.001	0.001	0.001	
Standard Supply Service – Administrative Charge (if applicable)	$	0.25	0.25	0.25	0.25	
General Service Less Than 50 kW						2.9%
Service Charge	$	32.49	32.58	32.87	21.34	
Service Charge Rate Rider for Storm Damage Cost Recovery - effective until August 31, 2009	$			0	0	
Distribution Volumetric Rate	$/kWh	0.0153	0.0153	0.0154	0.0243	
Distribution Volumetric Rate Rider for Storm Damage Cost Recovery - effective until August 31, 2009	$/kWh			0	0	
Rate Rider 1 (if applicable)				0		
Rate Rider 2 (if applicable)				0		
Regulatory Asset Recovery	$/kWh	0.0006	0.0006	0	0.0002	
Retail Transmission Rate – Network Service Rate	$/kWh	0.0047	0.0047	0.0039	0.0039	
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0039	0.0039	0.0037	0.0037	
Retail Transmission Rate – Network Service Rate (if applicable)	$/kWh			0		
Retail Transmission Rate – Line and Transformation Connection Service Rate (if applicable)	$/kWh			0		
Retail Transmission Rate – Network Service Rate (if applicable)	$/kWh			0		
Retail Transmission Rate – Line and Transformation Connection Service Rate (if applicable)	$/kWh			0		
Wholesale Market Service Rate	$/kWh	0.0052	0.0052	0.0052	0.0052	
Rural Rate Protection Charge	$/kWh	0.001	0.001	0.001	0.001	
Standard Supply Service – Administrative Charge (if applicable)	$	0.25	0.25	0.25	0.25	
General Service 50 to 4,999 kW						1.2%
Service Charge	$	755.96	758.14	764.96	148.11	
Service Charge Rate Rider for Storm Damage Cost Recovery - effective until August 31, 2009	$			0	0	

Canadian Niagara Power Inc. - Eastern Ontario Power
TARIFF OF RATES AND CHARGES

		May 1, 2006 Board Approved	May 1, 2007 Board Approved	May 1, 2008 Board Approved	May 1, 2009 2006 CA Allocations	Bill Impact CA Allocations
Distribution Volumetric Rate	$/kW	3.4821	3.4921	3.5235	8.1769	
Distribution Volumetric Rate Rider for Storm Damage Cost Recovery - effective until August 31, 2009	$/kW			0	0	
Rate Rider 1 (if applicable)				0		
Rate Rider 2 (if applicable)				0		
Regulatory Asset Recovery	$/kW	-0.1374	-0.1374	0	0.0656	
Retail Transmission Rate – Network Service Rate	$/kW	1.9261	1.9261	1.5794	1.6231	
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.5517	1.5517	1.4741	1.5725	
Retail Transmission Rate – Network Service Rate (if applicable)	$/kW			0		
Retail Transmission Rate – Line and Transformation Connection Service Rate (if applicable)	$/kW			0		
Retail Transmission Rate – Network Service Rate (if applicable)	$/kW			0		
Retail Transmission Rate – Line and Transformation Connection Service Rate (if applicable)	$/kW			0		
Wholesale Market Service Rate	$/kWh	0.0052	0.0052	0.0052	0.0052	
Rural Rate Protection Charge	$/kWh	0.001	0.001	0.001	0.001	
Standard Supply Service – Administrative Charge (if applicable)	$	0.25	0.25	0.25	0.25	
Unmetered Scattered Load						9.4%
Service Charge	$	32.49	32.58	32.87	36.39	
Service Charge Rate Rider for Storm Damage Cost Recovery - effective until August 31, 2009	$			0	0	
Distribution Volumetric Rate	$/kWh	0.0153	0.0153	0.0154	0.0232	
Distribution Volumetric Rate Rider for Storm Damage Cost Recovery - effective until August 31, 2009	$/kWh			0	0	
Rate Rider 1 (if applicable)				0		
Rate Rider 2 (if applicable)				0		
Regulatory Asset Recovery	$/kWh	0.0006	0.0006	0	0.0003	
Retail Transmission Rate – Network Service Rate	$/kWh	0.0047	0.0047	0.0039	0.0039	
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0039	0.0039	0.0037	0.0037	
Retail Transmission Rate – Network Service Rate (if applicable)	$/kWh			0		
Retail Transmission Rate – Line and Transformation Connection Service Rate (if applicable)	$/kWh			0		
Retail Transmission Rate – Network Service Rate (if applicable)	$/kWh			0		
Retail Transmission Rate – Line and Transformation Connection Service Rate (if applicable)	$/kWh			0		
Wholesale Market Service Rate	$/kWh	0.0052	0.0052	0.0052	0.0052	
Rural Rate Protection Charge	$/kWh	0.001	0.001	0.001	0.001	
Standard Supply Service – Administrative Charge (if applicable)	$	0.25	0.25	0.25	0.25	
Sentinel Lighting						8.4%
Service Charge	$	1.75	1.76	1.78	2.94	
Service Charge Rate Rider for Storm Damage Cost Recovery - effective until August 31, 2009	$			0	0	
Distribution Volumetric Rate	$/kW	2.5892	2.5967	2.6201	3.3822	
Distribution Volumetric Rate Rider for Storm Damage Cost Recovery - effective until August 31, 2009	$/kW			0	0	
Rate Rider 1 (if applicable)				0		
Rate Rider 2 (if applicable)				0		

Canadian Niagara Power Inc. - Eastern Ontario Power
TARIFF OF RATES AND CHARGES

		May 1, 2006 Board Approved	May 1, 2007 Board Approved	May 1, 2008 Board Approved	May 1, 2009 2006 CA Allocations	Bill Impact CA Allocations
Regulatory Asset Recovery	$/kW	1.5041	1.5041	0	0.0727	
Retail Transmission Rate – Network Service Rate	$/kW	1.46	1.46	1.1972	1.1972	
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2247	1.2247	1.1635	1.1635	
Retail Transmission Rate – Network Service Rate (if applicable)	$/kW			0		
Retail Transmission Rate – Line and Transformation Connection Service Rate (if applicable)	$/kW			0		
Retail Transmission Rate – Network Service Rate (if applicable)	$/kW			0		
Retail Transmission Rate – Line and Transformation Connection Service Rate (if applicable)	$/kW			0		
Wholesale Market Service Rate	$/kWh	0.0052	0.0052	0.0052	0.0052	
Rural Rate Protection Charge	$/kWh	0.001	0.001	0.001	0.001	
Standard Supply Service – Administrative Charge (if applicable)	$	0.25	0.25	0.25	0.25	
Street Lighting						1.6%
Service Charge	$	1.74	1.75	1.77	1.69	
Service Charge Rate Rider for Storm Damage Cost Recovery - effective until August 31, 2009	$			0	0	
Distribution Volumetric Rate	$/kW	2.3879	2.3948	2.4164	3.3232	
Distribution Volumetric Rate Rider for Storm Damage Cost Recovery - effective until August 31, 2009	$/kW			0	0	
Rate Rider 1 (if applicable)				0		
Rate Rider 2 (if applicable)				0		
Regulatory Asset Recovery	$/kW	0.9996	0.9996	0	0.0687	
Retail Transmission Rate – Network Service Rate	$/kW	1.4526	1.4526	1.1911	1.1911	
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.1996	1.1996	1.1396	1.1396	
Retail Transmission Rate – Network Service Rate (if applicable)	$/kW			0		
Retail Transmission Rate – Line and Transformation Connection Service Rate (if applicable)	$/kW			0		
Retail Transmission Rate – Network Service Rate (if applicable)	$/kW			0		
Retail Transmission Rate – Line and Transformation Connection Service Rate (if applicable)	$/kW			0		
Wholesale Market Service Rate	$/kWh	0.0052	0.0052	0.0052	0.0052	
Rural Rate Protection Charge	$/kWh	0.001	0.001	0.001	0.001	
Standard Supply Service – Administrative Charge (if applicable)	$	0.25	0.25	0.25	0.25	
Cost of Power 1st 600	$/kWh			0.053	0.053	
Balance	$/kWh			0.062	0.062	
Loss Factor		1.0715	1.0715	1.0715	1.0719	

Comparison of Rate Impacts Resulting from Harmonization Compared with 2009 Rate Impacts of Separately Calculated Rates

Customer Class	Fort Erie Only	Fort Erie Harmonized	EOP Only	EOP Harmonized
Residential	5.0%	4.9%	9.5%	9.4%
General Service Less Than 50 kW	3.1%	1.7%	3.1%	2.9%
General Service 50 to 4,999 kW	-0.5%	2.0%	8.6%	1.2%
Unmetered Scattered Load	9.3%	33.7%	4.0%	9.4%
Sentinel Lighting	9.8%	9.7%	9.9%	8.4%
Street Lighting	9.9%	9.9%	10.0%	1.6%

CNPI - FORT ERIE 2009 EDR
Rate Impacts May 2009 Compared To May 2008
Distribution Rates Calculated on the Basis of the Cost Allocational Informational Filing

Residential

Consumption	1,000	kWh	0	kW	Loss Factor 1.0391

	May 2008 BILL			May 2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Energy First Tier (kWh)	600	$ 0.0530	$ 31.80	600	$ 0.0530	$ 31.80	$0.00	0.0%	27.28%
Energy Second Tier (kWh)	448	$ 0.0620	$ 27.77	439	$ 0.0620	$ 27.22	($0.55)	(2.0)%	23.35%
Sub-Total: Energy			**$ 59.57**			**$ 59.02**	**($0.55)**	**(0.9)%**	**50.63%**
Monthly Service Charge	1	$ 20.06	$ 20.06	1	$ 17.96	$ 17.96	($2.10)	(10.5)%	15.40%
Distribution (kWh)	1,000	$ 0.0072	$ 7.20	1,000	$ 0.0150	$ 15.00	$7.80	108.3%	12.87%
Distribution (kW)	0	$ -	$ -	0	$ -	$ -	$0.00	0.0%	0.00%
Regulatory Assets (kWh)	1,000	$ -	$ -	1,000	$ 0.0002	$ 0.20	$0.20	0.0%	0.17%
Rate Riders	1,000	$ -	$ -	1,000	$ -	$ -	$0.00	0.0%	0.00%
Monthly Rate Rider Adjustment Z-Factor	1	$ 2.11	$ 2.11	1	$ 2.11	$ 2.11	$0.00	0.0%	1.81%
Volumetric Rate Rider Adjustment Z-Factor	1,000	$ 0.0008	$ 0.80	1,000	$ 0.0008	$ 0.80	$0.00	0.0%	0.69%
Retail Transmission Rate – Network Service Rate	1,048	$ 0.0044	$ 4.61	1,039	$ 0.0044	$ 4.57	($0.04)	(0.8)%	3.92%
Retail Transmission Rate – Line and Transformation Connection Service Rate	1,048	$ 0.0045	$ 4.72	1,039	$ 0.0045	$ 4.68	($0.04)	(0.8)%	4.01%
Sub-Total: Delivery			**$ 39.50**			**$ 45.32**	**$5.82**	**14.7%**	**38.87%**
Wholesale Market Service Rate	1,048	$ 0.0052	$ 5.45	1039	$ 0.0052	$ 5.40	($0.05)	(0.8)%	4.63%
Rural Rate Protection Charge	1,048	$ 0.0010	$ 1.05	1039	$ 0.0010	$ 1.04	($0.01)	(0.8)%	0.89%
Regulated Price Plan – Administration Charge	1	$ 0.2500	$ 0.25	1	$ 0.2500	$ 0.25	$0.00	0.0%	0.21%
Sub-Total: Regulatory			**$ 6.75**			**$ 6.69**	**($0.05)**	**(0.8)%**	**5.74%**
Debt Retirement Charge (DRC)	1,000	$ -	**$ -**	1,000	$ -	**$ -**	**$0.00**	**0.0%**	**0.0%**
Total Bill before Taxes			**$ 105.81**			**$ 111.03**	**$5.22**	**4.9%**	**95.24%**
GST	$ 105.81	5%	**$ 5.29**	$ 111.03	5%	**$ 5.55**	**$0.26**	**4.9%**	**4.76%**
Total Bill after Taxes			**$ 111.10**			**$ 116.59**	**$5.48**	**4.9%**	**100.00%**

General Service Less Than 50 kW

Consumption	2,000	kWh	0	kW	Loss Factor 1.0391

	May 2008 BILL			May 2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Energy First Tier (kWh)	750	$ 0.0530	$ 39.75	750	$ 0.0530	$ 39.75	$0.00	0.0%	16.78%
Energy Second Tier (kWh)	1,346	$ 0.0620	$ 83.44	1,328	$ 0.0620	$ 82.35	($1.09)	(1.3)%	34.76%
Sub-Total: Energy			**$ 123.19**			**$ 122.10**	**($1.09)**	**(0.9)%**	**51.53%**
Monthly Service Charge	1	$ 17.56	$ 17.56	1	$ 21.34	$ 21.34	$3.78	21.5%	9.01%
Distribution (kWh)	2,000	$ 0.0222	$ 44.40	2,000	$ 0.0228	$ 45.60	$1.20	2.7%	19.25%
Distribution (kW)	0	$ -	$ -	0	$ -	$ -	$0.00	0.0%	0.00%
Regulatory Assets (kWh)	2,000	$ -	$ -	2,000	$ 0.0001	$ 0.20	$0.20	0.0%	0.08%
Rate Riders	2,000	$ -	$ -	2,000	$ -	$ -	$0.00	0.0%	0.00%
Monthly Rate Rider Adjustment Z-Factor	1	$ 1.85	$ 1.85	1	$ 1.85	$ 1.85	$0.00	0.0%	0.78%
Volumetric Rate Rider Adjustment Z-Factor	2,000	$ 0.0024	$ 4.80	2,000	$ 0.0024	$ 4.80	$0.00	0.0%	2.03%
Retail Transmission Rate – Network Service Rate	2,096	$ 0.0040	$ 8.38	2,078	$ 0.0040	$ 8.31	($0.07)	(0.8)%	3.51%
Retail Transmission Rate – Line and Transformation Connection Service Rate	2,096	$ 0.0040	$ 8.38	2,078	$ 0.0040	$ 8.31	($0.07)	(0.8)%	3.51%
Sub-Total: Delivery			**$ 85.38**			**$ 90.42**	**$5.04**	**5.9%**	**38.16%**
Wholesale Market Service Rate	2,096	$ 0.0052	$ 10.90	2,078	$ 0.0052	$ 10.81	($0.09)	(0.8)%	4.56%
Rural Rate Protection Charge	2,096	$ 0.0010	$ 2.10	2,078	$ 0.0010	$ 2.08	($0.02)	(0.8)%	0.88%
Regulated Price Plan – Administration Charge	1	$ 0.2500	$ 0.25	1	$ 0.2500	$ 0.25	$0.00	0.0%	0.11%
Sub-Total: Regulatory			**$ 13.24**			**$ 13.13**	**($0.11)**	**(0.8)%**	**5.54%**
Debt Retirement Charge (DRC)	2,000	$ -	**$ -**	2,000	$ -	**$ -**	**$0.00**	**0.0%**	**0.00%**
Total Bill before Taxes			**$ 221.81**			**$ 225.65**	**$3.84**	**1.7%**	**95.24%**
GST	$ 221.81	5%	**$ 11.09**	$ 225.65	5%	**$ 11.28**	**$0.19**	**1.7%**	**4.76%**
Total Bill after Taxes			**$ 232.90**			**$ 236.93**	**$4.03**	**1.7%**	**100.00%**

General Service 50 to 4,999 kW

Consumption	83,747	kWh	226	kW	Loss Factor 1.0391

	May 2008 BILL			May 2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Energy First Tier (kWh)	750	$ 0.0530	$ 39.75	750	$ 0.0530	$ 39.75	$0.00	0.0%	0.43%
Energy Second Tier (kWh)	87,008	$ 0.0620	$ 5,394.53	86,272	$ 0.0620	$ 5,348.83	($45.69)	(0.8)%	57.52%
Sub-Total: Energy			**$ 5,434.28**			**$ 5,388.58**	**($45.69)**	**(0.8)%**	**57.95%**
Monthly Service Charge	1	$ 116.52	$ 116.52	1	$ 148.11	$ 148.11	$31.59	27.1%	1.59%
Distribution (kWh)	83,747	$ -	$ -	83,747	$ -	$ -	$0.00	0.0%	0.00%
Distribution (kW)	226	$ 7.2398	$ 1,636.19	226	$ 8.0620	$ 1,822.01	$185.82	11.4%	19.59%
Regulatory Assets (kW)	226	$ -	$ -	226	$ 0.0391	$ 8.84	$8.84	0.0%	0.10%
Rate Riders	226	$ -	$ -	226	$ -	$ -	$0.00	0.0%	0.00%
Monthly Rate Rider Adjustment Z-Factor	1	$ 12.42	$ 12.42	1	$ 12.42	$ 12.42	$0.00	0.0%	0.13%
Volumetric Rate Rider Adjustment Z-Factor	226	$ 0.7737	$ 174.86	226	$ 0.7737	$ 174.86	$0.00	0.0%	1.88%
Retail Transmission Rate – Network Service Rate	237	$ 1.6442	$ 389.39	235	$ 1.6442	$ 386.12	($3.27)	(0.8)%	4.15%
Retail Transmission Rate – Line and Transformation Connection Service Rate	237	$ 1.5973	$ 378.28	235	$ 1.5973	$ 375.10	($3.18)	(0.8)%	4.03%
Sub-Total: Delivery			**$ 2,707.66**			**$ 2,927.46**	**$219.80**	**8.1%**	**31.48%**
Wholesale Market Service Rate	87,758	$ 0.0052	$ 456.34	87022	$ 0.0052	$ 452.51	($3.83)	(0.8)%	4.87%
Rural Rate Protection Charge	87,758	$ 0.0010	$ 87.76	87022	$ 0.0010	$ 87.02	($0.74)	(0.8)%	0.94%
Regulated Price Plan – Administration Charge	1	$ 0.2500	$ 0.25	1	$ 0.2500	$ 0.25	$0.00	0.0%	0.00%
Sub-Total: Regulatory			**$ 544.35**			**$ 539.78**	**($4.57)**	**(0.8)%**	**5.80%**
Debt Retirement Charge (DRC)	83,747	$ -	**$ -**	83,747	$ -	**$ -**	**$0.00**	**0.0%**	**0.00%**
Total Bill before Taxes			**$ 8,686.29**			**$ 8,855.82**	**$169.54**	**2.0%**	**95.24%**
GST	$ 8,686.29	5%	**$ 434.31**	$ 8,855.82	5%	**$ 442.79**	**$8.48**	**2.0%**	**4.76%**
Total Bill after Taxes			**$ 9,120.60**			**$ 9,298.62**	**$178.01**	**2.0%**	**100.00%**

Unmetered Scattered Load

Consumption	750	kWh	0	kW	Loss Factor 1.0391

	May 2008 BILL			May 2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Energy First Tier (kWh)	750	$ 0.0530	$ 39.75	750	$ 0.0530	$ 39.75	$0.00	0.0%	34.90%
Energy Second Tier (kWh)	36	$ 0.0620	$ 2.23	29	$ 0.0620	$ 1.82	($0.41)	(18.4)%	1.60%
Sub-Total: Energy			**$ 41.98**			**$ 41.57**	**($0.41)**	**(1.0)%**	**36.49%**
Monthly Service Charge	1	$ 8.56	$ 8.56	1	$ 36.39	$ 36.39	$27.83	325.1%	31.95%
Distribution (kWh)	750	$ 0.0220	$ 16.50	750	$ 0.0217	$ 16.28	($0.22)	(1.4)%	14.29%
Distribution (kW)	0	$ -	$ -	0	$ -	$ -	$0.00	0.0%	0.00%
Regulatory Assets (kWh)	750	$ -	$ -	750	$ 0.0003	$ 0.23	$0.23	0.0%	0.20%
Rate Riders	750	$ -	$ -	750	$ -	$ -	$0.00	0.0%	0.00%
Monthly Rate Rider Adjustment Z-Factor	1	$ 0.91	$ 0.91	1	$ 0.91	$ 0.91	$0.00	0.0%	0.80%
Volumetric Rate Rider Adjustment Z-Factor	750	$ 0.0024	$ 1.80	750	$ 0.0024	$ 1.80	$0.00	0.0%	1.58%
Retail Transmission Rate – Network Service Rate	786	$ 0.0040	$ 3.14	779	$ 0.0040	$ 3.12	($0.03)	(0.8)%	2.74%
Retail Transmission Rate – Line and Transformation Connection Service Rate	786	$ 0.0040	$ 3.14	779	$ 0.0040	$ 3.12	($0.03)	(0.8)%	2.74%
Sub-Total: Delivery			**$ 34.06**			**$ 61.83**	**$27.78**	**81.6%**	**54.28%**
Wholesale Market Service Rate	786	$ 0.0052	$ 4.09	779	$ 0.0052	$ 4.05	($0.03)	(0.8)%	3.56%
Rural Rate Protection Charge	786	$ 0.0010	$ 0.79	779	$ 0.0010	$ 0.78	($0.01)	(0.8)%	0.68%
Regulated Price Plan – Administration Charge	1	$ 0.2500	$ 0.25	1	$ 0.2500	$ 0.25	$0.00	0.0%	0.22%
Sub-Total: Regulatory			**$ 5.12**			**$ 5.08**	**($0.04)**	**(0.8)%**	**4.46%**
Debt Retirement Charge (DRC)	750	$ -	**$ -**	750	$ -	**$ -**	**$0.00**	**0.0%**	**0.00%**
Total Bill before Taxes			**$ 81.16**			**$ 108.48**	**$27.33**	**33.7%**	**95.24%**
GST	$ 81.16	5%	**$ 4.06**	$ 108.48	5%	**$ 5.42**	**$1.37**	**33.7%**	**4.76%**
Total Bill after Taxes			**$ 85.22**			**$ 113.91**	**$28.69**	**33.7%**	**100.00%**

Sentinel Lighting

Consumption	3,000	kWh	10	kW	Loss Factor 1.0391

	May 2008 BILL			May 2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Energy First Tier (kWh)	750	$ 0.0530	$ 39.75	750	$ 0.0530	$ 39.75	$0.00	0.0%	11.74%
Energy Second Tier (kWh)	2,394	$ 0.0620	$ 148.41	2,367	$ 0.0620	$ 146.77	($1.64)	(1.1)%	43.36%
Sub-Total: Energy			**$ 188.16**			**$ 186.52**	**($1.64)**	**(0.9)%**	**55.11%**
Monthly Service Charge	17	$ 1.97	$ 33.49	17	$ 2.94	$ 49.98	$16.49	49.2%	14.77%
Distribution (kWh)	3,000	$ -	$ -	3,000	$ -	$ -	$0.00	0.0%	0.00%
Distribution (kW)	10	$ 1.9700	$ 19.70	10	$ 3.3290	$ 33.29	$13.59	69.0%	9.84%
Regulatory Assets (kWh)	10	$ -	$ -	10	$ 0.0574	$ 0.57	$0.57	0.0%	0.17%
Rate Riders	10	$ -	$ -	10	$ -	$ -	$0.00	0.0%	0.00%
Monthly Rate Rider Adjustment Z-Factor	17	$ 0.21	$ 3.57	17	$ 0.21	$ 3.57	$0.00	0.0%	1.05%
Volumetric Rate Rider Adjustment Z-Factor	10	$ 0.2105	$ 2.11	10	$ 0.2105	$ 2.11	$0.00	0.0%	0.62%
Retail Transmission Rate – Network Service Rate	10	$ 1.3124	$ 13.75	10	$ 1.3124	$ 13.64	($0.12)	(0.8)%	4.03%
Retail Transmission Rate – Line and Transformation Connection Service Rate	10	$ 1.2607	$ 13.21	10	$ 1.2607	$ 13.10	($0.11)	(0.8)%	3.87%
Sub-Total: Delivery			**$ 85.83**			**$ 116.26**	**$30.43**	**35.5%**	**34.35%**
Wholesale Market Service Rate	3,144	$ 0.0052	$ 16.35	3,117	$ 0.0052	$ 16.21	($0.14)	(0.8)%	4.79%
Rural Rate Protection Charge	3,144	$ 0.0010	$ 3.14	3,117	$ 0.0010	$ 3.12	($0.03)	(0.8)%	0.92%
Regulated Price Plan – Administration Charge	1	$ 0.2500	$ 0.25	1	$ 0.2500	$ 0.25	$0.00	0.0%	0.07%
Sub-Total: Regulatory			**$ 19.74**			**$ 19.58**	**($0.16)**	**(0.8)%**	**5.78%**
Debt Retirement Charge (DRC)	3,000	$ -	**$ -**	3,000	$ -	**$ -**	**$0.00**	**0.0%**	**0.00%**
Total Bill before Taxes			**$ 293.73**			**$ 322.36**	**$28.63**	**9.7%**	**95.24%**
GST	$ 293.73	5%	**$ 14.69**	$ 322.36	5%	**$ 16.12**	**$1.43**	**9.7%**	**4.76%**
Total Bill after Taxes			**$ 308.42**			**$ 338.47**	**$30.06**	**9.7%**	**100.00%**

Street Lighting

Consumption	172,000	kWh	491	kW	Loss Factor 1.0391

	May 2008 BILL			May 2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Energy First Tier (kWh)	750	$ 0.0530	$ 39.75	750	$ 0.0530	$ 39.75	$0.00	0.0%	0.19%
Energy Second Tier (kWh)	179,489	$ 0.0620	$ 11,128.31	177,975	$ 0.0620	$ 11,034.46	($93.84)	(0.8)%	51.44%
Sub-Total: Energy			**$ 11,168.06**			**$ 11,074.21**	**($93.84)**	**(0.8)%**	**51.63%**
Monthly Service Charge	2873	$ 1.31	$ 3,763.63	2873	$ 1.69	$ 4,855.37	$1,091.74	29.0%	22.64%
Distribution (kWh)	172,000	$ -	$ -	172,000	$ -	$ -	$0.00	0.0%	0.00%
Distribution (kW)	491	$ 1.5823	$ 776.91	491	$ 3.3000	$ 1,620.30	$843.39	108.6%	7.55%
Regulatory Assets (kWh)	491	$ -	$ -	491	$ 0.0445	$ 21.85	$21.85	0.0%	0.10%
Rate Riders	491	$ -	$ -	491	$ -	$ -	$0.00	0.0%	0.00%
Monthly Rate Rider Adjustment Z-Factor	2873	$ 0.14	$ 402.22	2873	$ 0.14	$ 402.22	$0.00	0.0%	1.88%
Volumetric Rate Rider Adjustment Z-Factor	491	$ 0.1691	$ 83.03	491	$ 0.1691	$ 83.03	$0.00	0.0%	0.39%
Retail Transmission Rate – Network Service Rate	515	$ 1.2400	$ 638.00	510	$ 1.2400	$ 632.65	($5.36)	(0.8)%	2.95%
Retail Transmission Rate – Line and Transformation Connection Service Rate	515	$ 1.2348	$ 635.33	510	$ 1.2348	$ 629.99	($5.34)	(0.8)%	2.94%
Sub-Total: Delivery			**$ 6,299.12**			**$ 8,245.41**	**$1,946.29**	**30.9%**	**38.44%**
Wholesale Market Service Rate	180239	$ 0.0052	$ 937.24	178725	$ 0.0052	$ 929.37	($7.87)	(0.8)%	4.33%
Rural Rate Protection Charge	180239	$ 0.0010	$ 180.24	178725	$ 0.0010	$ 178.73	($1.51)	(0.8)%	0.83%
Regulated Price Plan – Administration Charge	1	$ 0.2500	$ 0.25	1	$ 0.2500	$ 0.25	$0.00	0.0%	0.00%
Sub-Total: Regulatory			**$ 1,117.73**			**$ 1,108.35**	**($9.38)**	**(0.8)%**	**5.17%**
Debt Retirement Charge (DRC)	172,000	$ -	**$ -**	172,000	$ -	**$ -**	**$0.00**	**0.0%**	**0.00%**
Total Bill before Taxes			**$ 18,584.90**			**$ 20,427.96**	**$1,843.06**	**9.9%**	**95.24%**
GST	$ 18,584.90	5%	**$ 929.25**	$ 20,427.96	5%	**$ 1,021.40**	**$92.15**	**9.9%**	**4.76%**
Total Bill after Taxes			**$ 19,514.15**			**$ 21,449.36**	**$1,935.21**	**9.9%**	**100.00%**

CNPI - Eastern Ontario Power 2009 EDR
Rate Impacts May 2009 Compared To May 2008
Distribution Rates Calculated on the Basis of the Cost Allocational Informational Filing

Residential

Consumption	1,000	kWh	0	kW	Loss Factor 1.0719

	May 2008 BILL			May 2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Energy First Tier (kWh)	600	$ 0.0530	$ 31.80	600	$ 0.0530	$ 31.80	$0.00	0.0%	26.19%
Energy Second Tier (kWh)	472	$ 0.0620	$ 29.23	472	$ 0.0620	$ 29.26	$0.02	0.1%	24.10%
Sub-Total: Energy			**$ 61.03**			**$ 61.06**	**$0.02**	**0.0%**	**50.30%**
Monthly Service Charge	1	$ 16.32	$ 16.32	1	$ 17.96	$ 17.96	$1.64	10.0%	14.79%
Distribution (kWh)	1,000	$ 0.0073	$ 7.30	1,000	$ 0.0154	$ 15.40	$8.10	111.0%	12.69%
Distribution (kW)	0	$ -	$ -	0	$ -	$ -	$0.00	0.0%	0.00%
Regulatory Assets (kWh)	1,000	$ -	$ -	1,000	$ 0.0002	$ 0.20	$0.20	0.0%	0.16%
Rate Riders	1,000	$ -	$ -	1,000	$ -	$ -	$0.00	0.0%	0.00%
Monthly Rate Rider Adjustment Z-Factor	1	$ -	$ -	1	$ -	$ -	$0.00	0.0%	0.00%
Volumetric Rate Rider Adjustment Z-Factor	1,000	$ -	$ -	1,000	$ -	$ -	$0.00	0.0%	0.00%
Retail Transmission Rate – Network Service Rate	1,072	$ 0.0043	$ 4.61	1,072	$ 0.0043	$ 4.61	$0.00	0.0%	3.80%
Retail Transmission Rate – Line and Transformation Connection Service Rate	1,072	$ 0.0041	$ 4.39	1,072	$ 0.0041	$ 4.39	$0.00	0.0%	3.62%
Sub-Total: Delivery			**$ 32.62**			**$ 42.56**	**$9.94**	**30.5%**	**35.06%**
Wholesale Market Service Rate	1,072	$ 0.0052	$ 5.57	1,072	$ 0.0052	$ 5.57	$0.00	0.0%	4.59%
Rural Rate Protection Charge	1,072	$ 0.0010	$ 1.07	1,072	$ 0.0010	$ 1.07	$0.00	0.0%	0.88%
Regulated Price Plan – Administration Charge	1	$ 0.2500	$ 0.25	1	$ 0.2500	$ 0.25	$0.00	0.0%	0.21%
Sub-Total: Regulatory			**$ 6.89**			**$ 6.90**	**$0.00**	**0.0%**	**5.68%**
Debt Retirement Charge (DRC)	1,000	$ 0.0051	**$ 5.10**	1,000	$ 0.0051	**$ 5.10**	**$0.00**	**0.0%**	**4.2%**
Total Bill before Taxes			**$ 105.65**			**$ 115.62**	**$9.97**	**9.4%**	**95.24%**
GST	$ 105.65	5%	**$ 5.28**	$ 115.62	5%	**$ 5.78**	**$0.50**	**9.4%**	**4.76%**
Total Bill after Taxes			**$ 110.93**			**$ 121.40**	**$10.47**	**9.4%**	**100.00%**

General Service Less Than 50 kW

Consumption	2,000	kWh	0	kW	Loss Factor 1.0719

	May 2008 BILL			May 2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Energy First Tier (kWh)	750	$ 0.0530	$ 39.75	750	$ 0.0530	$ 39.75	$0.00	0.0%	16.00%
Energy Second Tier (kWh)	1,393	$ 0.0620	$ 86.37	1,394	$ 0.0620	$ 86.42	$0.05	0.1%	34.79%
Sub-Total: Energy			**$ 126.12**			**$ 126.17**	**$0.05**	**0.0%**	**50.80%**
Monthly Service Charge	1	$ 32.87	$ 32.87	1	$ 21.34	$ 21.34	($11.53)	(35.1)%	8.59%
Distribution (kWh)	2,000	$ 0.0154	$ 30.80	2,000	$ 0.0243	$ 48.60	$17.80	57.8%	19.57%
Distribution (kW)	0	$ -	$ -	0	$ -	$ -	$0.00	0.0%	0.00%
Regulatory Assets (kWh)	2,000	$ -	$ -	2,000	$ 0.0002	$ 0.40	$0.40	0.0%	0.16%
Rate Riders	2,000	$ -	$ -	2,000	$ -	$ -	$0.00	0.0%	0.00%
Monthly Rate Rider Adjustment Z-Factor	1	$ -	$ -	1	$ -	$ -	$0.00	0.0%	0.00%
Volumetric Rate Rider Adjustment Z-Factor	2,000	$ -	$ -	2,000	$ -	$ -	$0.00	0.0%	0.00%
Retail Transmission Rate – Network Service Rate	2,143	$ 0.0039	$ 8.36	2,144	$ 0.0039	$ 8.36	$0.00	0.0%	3.37%
Retail Transmission Rate – Line and Transformation Connection Service Rate	2,143	$ 0.0037	$ 7.93	2,144	$ 0.0037	$ 7.93	$0.00	0.0%	3.19%
Sub-Total: Delivery			**$ 79.96**			**$ 86.63**	**$6.68**	**8.3%**	**34.88%**
Wholesale Market Service Rate	2,143	$ 0.0052	$ 11.14	2,144	$ 0.0052	$ 11.15	$0.00	0.0%	4.49%
Rural Rate Protection Charge	2,143	$ 0.0010	$ 2.14	2,144	$ 0.0010	$ 2.14	$0.00	0.0%	0.86%
Regulated Price Plan – Administration Charge	1	$ 0.2500	$ 0.25	1	$ 0.2500	$ 0.25	$0.00	0.0%	0.10%
Sub-Total: Regulatory			**$ 13.54**			**$ 13.54**	**$0.00**	**0.0%**	**5.45%**
Debt Retirement Charge (DRC)	2,000	$ 0.0051	**$ 10.20**	2,000	$ 0.0051	**$ 10.20**	**$0.00**	**0.0%**	**4.11%**
Total Bill before Taxes			**$ 229.81**			**$ 236.54**	**$6.73**	**2.9%**	**95.24%**
GST	$ 229.81	5%	**$ 11.49**	$ 236.54	5%	**$ 11.83**	**$0.34**	**2.9%**	**4.76%**
Total Bill after Taxes			**$ 241.30**			**$ 248.37**	**$7.07**	**2.9%**	**100.00%**

General Service 50 to 4,999 kW

Consumption	44,320	kWh	139	kW	Loss Factor 1.0719

	May 2008 BILL			May 2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Energy First Tier (kWh)	750	$ 0.0530	$ 39.75	750	$ 0.0530	$ 39.75	$0.00	0.0%	0.72%
Energy Second Tier (kWh)	46,739	$ 0.0620	$ 2,897.81	46,757	$ 0.0620	$ 2,898.91	$1.10	0.0%	52.79%
Sub-Total: Energy			**$ 2,937.56**			**$ 2,938.66**	**$1.10**	**0.0%**	**53.52%**
Monthly Service Charge	1	$ 764.96	$ 764.96	1	$ 148.11	$ 148.11	($616.85)	(80.6)%	2.70%
Distribution (kWh)	44,320	$ -	$ -	44,320	$ -	$ -	$0.00	0.0%	0.00%
Distribution (kW)	139	$ 3.5235	$ 489.77	139	$ 8.1769	$ 1,136.59	$646.82	132.1%	20.70%
Regulatory Assets (kW)	139	$ -	$ -	139	$ 0.0656	$ 9.12	$9.12	0.0%	0.17%
Rate Riders	139	$ -	$ -	139	$ -	$ -	$0.00	0.0%	0.00%
Monthly Rate Rider Adjustment Z-Factor	1	$ -	$ -	1	$ -	$ -	$0.00	0.0%	0.00%
Volumetric Rate Rider Adjustment Z-Factor	139	$ -	$ -	139	$ -	$ -	$0.00	0.0%	0.00%
Retail Transmission Rate – Network Service Rate	149	$ 1.5794	$ 235.23	149	$ 1.6231	$ 241.83	$6.59	2.8%	4.40%
Retail Transmission Rate – Line and Transformation Connection Service Rate	149	$ 1.4741	$ 219.55	149	$ 1.5725	$ 234.29	$14.74	6.7%	4.27%
Sub-Total: Delivery			**$ 1,709.51**			**$ 1,769.94**	**$60.43**	**3.5%**	**32.23%**
Wholesale Market Service Rate	47,489	$ 0.0052	$ 246.94	47507	$ 0.0052	$ 247.03	$0.09	0.0%	4.50%
Rural Rate Protection Charge	47,489	$ 0.0010	$ 47.49	47507	$ 0.0010	$ 47.51	$0.02	0.0%	0.87%
Regulated Price Plan – Administration Charge	1	$ 0.2500	$ 0.25	1	$ 0.2500	$ 0.25	$0.00	0.0%	0.00%
Sub-Total: Regulatory			**$ 294.68**			**$ 294.79**	**$0.11**	**0.0%**	**5.37%**
Debt Retirement Charge (DRC)	44,320	$ 0.0051	**$ 226.03**	44,320	$ 0.0051	**$ 226.03**	**$0.00**	**0.0%**	**4.12%**
Total Bill before Taxes			**$ 5,167.78**			**$ 5,229.42**	**$61.64**	**1.2%**	**95.24%**
GST	$ 5,167.78	5%	**$ 258.39**	$ 5,229.42	5%	**$ 261.47**	**$3.08**	**1.2%**	**4.76%**
Total Bill after Taxes			**$ 5,426.17**			**$ 5,490.89**	**$64.72**	**1.2%**	**100.00%**

Unmetered Scattered Load

Consumption	750	kWh	0	kW	Loss Factor 1.0719

	May 2008 BILL			May 2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Energy First Tier (kWh)	750	$ 0.0530	$ 39.75	750	$ 0.0530	$ 39.75	$0.00	0.0%	33.72%
Energy Second Tier (kWh)	54	$ 0.0620	$ 3.32	54	$ 0.0620	$ 3.34	$0.02	0.6%	2.84%
Sub-Total: Energy			**$ 43.07**			**$ 43.09**	**$0.02**	**0.0%**	**36.55%**
Monthly Service Charge	1	$ 32.87	$ 32.87	1	$ 36.39	$ 36.39	$3.52	10.7%	30.87%
Distribution (kWh)	750	$ 0.0154	$ 11.55	750	$ 0.0232	$ 17.40	$5.85	50.6%	14.76%
Distribution (kW)	0	$ -	$ -	0	$ -	$ -	$0.00	0.0%	0.00%
Regulatory Assets (kWh)	750	$ -	$ -	750	$ 0.0003	$ 0.23	$0.23	0.0%	0.19%
Rate Riders	750	$ -	$ -	750	$ -	$ -	$0.00	0.0%	0.00%
Monthly Rate Rider Adjustment Z-Factor	1	$ -	$ -	1	$ -	$ -	$0.00	0.0%	0.00%
Volumetric Rate Rider Adjustment Z-Factor	750	$ -	$ -	750	$ -	$ -	$0.00	0.0%	0.00%
Retail Transmission Rate – Network Service Rate	804	$ 0.0039	$ 3.13	804	$ 0.0039	$ 3.14	$0.00	0.0%	2.66%
Retail Transmission Rate – Line and Transformation Connection Service Rate	804	$ 0.0037	$ 2.97	804	$ 0.0037	$ 2.97	$0.00	0.0%	2.52%
Sub-Total: Delivery			**$ 50.53**			**$ 60.12**	**$9.60**	**19.0%**	**51.00%**
Wholesale Market Service Rate	804	$ 0.0052	$ 4.18	804	$ 0.0052	$ 4.18	$0.00	0.0%	3.55%
Rural Rate Protection Charge	804	$ 0.0010	$ 0.80	804	$ 0.0010	$ 0.80	$0.00	0.0%	0.68%
Regulated Price Plan – Administration Charge	1	$ 0.2500	$ 0.25	1	$ 0.2500	$ 0.25	$0.00	0.0%	0.21%
Sub-Total: Regulatory			**$ 5.23**			**$ 5.23**	**$0.00**	**0.0%**	**4.44%**
Debt Retirement Charge (DRC)	750	$ 0.0051	**$ 3.83**	750	$ 0.0051	**$ 3.83**	**$0.00**	**0.0%**	**3.24%**
Total Bill before Taxes			**$ 102.66**			**$ 112.28**	**$9.62**	**9.4%**	**95.24%**
GST	$ 102.66	5%	**$ 5.13**	$ 112.28	5%	**$ 5.61**	**$0.48**	**9.4%**	**4.76%**
Total Bill after Taxes			**$ 107.79**			**$ 117.89**	**$10.10**	**9.4%**	**100.00%**

Sentinel Lighting

Consumption	3,000	kWh	10	kW	Loss Factor 1.0719

	May 2008 BILL			May 2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Energy First Tier (kWh)	750	$ 0.0530	$ 39.75	750	$ 0.0530	$ 39.75	$0.00	0.0%	11.40%
Energy Second Tier (kWh)	2,465	$ 0.0620	$ 152.80	2,466	$ 0.0620	$ 152.87	$0.07	0.0%	43.85%
Sub-Total: Energy			**$ 192.55**			**$ 192.62**	**$0.07**	**0.0%**	**55.25%**
Monthly Service Charge	15	$ 1.78	$ 26.70	15	$ 2.94	$ 44.10	$17.40	65.2%	12.65%
Distribution (kWh)	3,000	$ -	$ -	3,000	$ -	$ -	$0.00	0.0%	0.00%
Distribution (kW)	10	$ 2.6201	$ 26.20	10	$ 3.3822	$ 33.82	$7.62	29.1%	9.70%
Regulatory Assets (kWh)	10	$ -	$ -	10	$ 0.0727	$ 0.73	$0.73	0.0%	0.21%
Rate Riders	10	$ -	$ -	10	$ -	$ -	$0.00	0.0%	0.00%
Monthly Rate Rider Adjustment Z-Factor	1	$ -	$ -	1	$ -	$ -	$0.00	0.0%	0.00%
Volumetric Rate Rider Adjustment Z-Factor	10	$ -	$ -	10	$ -	$ -	$0.00	0.0%	0.00%
Retail Transmission Rate – Network Service Rate	11	$ 1.1972	$ 12.83	11	$ 1.1972	$ 12.83	$0.00	0.0%	3.68%
Retail Transmission Rate – Line and Transformation Connection Service Rate	11	$ 1.1635	$ 12.47	11	$ 1.1635	$ 12.47	$0.00	0.0%	3.58%
Sub-Total: Delivery			**$ 78.20**			**$ 103.95**	**$25.76**	**32.9%**	**29.81%**
Wholesale Market Service Rate	3,215	$ 0.0052	$ 16.72	3,216	$ 0.0052	$ 16.72	$0.01	0.0%	4.80%
Rural Rate Protection Charge	3,215	$ 0.0010	$ 3.21	3,216	$ 0.0010	$ 3.22	$0.00	0.0%	0.92%
Regulated Price Plan – Administration Charge	1	$ 0.2500	$ 0.25	1	$ 0.2500	$ 0.25	$0.00	0.0%	0.07%
Sub-Total: Regulatory			**$ 20.18**			**$ 20.19**	**$0.01**	**0.0%**	**5.79%**
Debt Retirement Charge (DRC)	3,000	$ 0.0051	**$ 15.30**	3,000	$ 0.0051	**$ 15.30**	**$0.00**	**0.0%**	**4.39%**
Total Bill before Taxes			**$ 306.22**			**$ 332.06**	**$25.84**	**8.4%**	**95.24%**
GST	$ 306.22	5%	**$ 15.31**	$ 332.06	5%	**$ 16.60**	**$1.29**	**8.4%**	**4.76%**
Total Bill after Taxes			**$ 321.54**			**$ 348.67**	**$27.13**	**8.4%**	**100.00%**

Street Lighting

Consumption	46,000	kWh	129	kW	Loss Factor 1.0719

	May 2008 BILL			May 2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Energy First Tier (kWh)	750	$ 0.0530	$ 39.75	750	$ 0.0530	$ 39.75	$0.00	0.0%	0.72%
Energy Second Tier (kWh)	48,539	$ 0.0620	$ 3,009.42	48,557	$ 0.0620	$ 3,010.56	$1.14	0.0%	54.18%
Sub-Total: Energy			**$ 3,049.17**			**$ 3,050.31**	**$1.14**	**0.0%**	**54.89%**
Monthly Service Charge	557	$ 1.77	$ 985.89	557	$ 1.69	$ 941.33	($44.56)	(4.5)%	16.94%
Distribution (kWh)	46,000	$ -	$ -	46,000	$ -	$ -	$0.00	0.0%	0.00%
Distribution (kW)	129	$ 2.4164	$ 311.72	129	$ 3.3232	$ 428.69	$116.98	37.5%	7.71%
Regulatory Assets (kWh)	129	$ -	$ -	129	$ 0.0687	$ 8.86	$8.86	0.0%	0.16%
Rate Riders	129	$ -	$ -	129	$ -	$ -	$0.00	0.0%	0.00%
Monthly Rate Rider Adjustment Z-Factor	1	$ -	$ -	1	$ -	$ -	$0.00	0.0%	0.00%
Volumetric Rate Rider Adjustment Z-Factor	129	$ -	$ -	129	$ -	$ -	$0.00	0.0%	0.00%
Retail Transmission Rate – Network Service Rate	138	$ 1.1911	$ 164.64	138	$ 1.1911	$ 164.70	$0.06	0.0%	2.96%
Retail Transmission Rate – Line and Transformation Connection Service Rate	138	$ 1.1396	$ 157.52	138	$ 1.1396	$ 157.58	$0.06	0.0%	2.84%
Sub-Total: Delivery			**$ 1,619.76**			**$ 1,701.16**	**$81.40**	**5.0%**	**30.62%**
Wholesale Market Service Rate	49289	$ 0.0052	$ 256.30	49307	$ 0.0052	$ 256.40	$0.10	0.0%	4.61%
Rural Rate Protection Charge	49289	$ 0.0010	$ 49.29	49307	$ 0.0010	$ 49.31	$0.02	0.0%	0.89%
Regulated Price Plan – Administration Charge	1	$ 0.2500	$ 0.25	1	$ 0.2500	$ 0.25	$0.00	0.0%	0.00%
Sub-Total: Regulatory			**$ 305.84**			**$ 305.96**	**$0.11**	**0.0%**	**5.51%**
Debt Retirement Charge (DRC)	46,000	$ 0.0051	**$ 234.60**	46,000	$ 0.0051	**$ 234.60**	**$0.00**	**0.0%**	**4.22%**
Total Bill before Taxes			**$ 5,209.37**			**$ 5,292.03**	**$82.65**	**1.6%**	**95.24%**
GST	$ 5,209.37	5%	**$ 260.47**	$ 5,292.03	5%	**$ 264.60**	**$4.13**	**1.6%**	**4.76%**
Total Bill after Taxes			**$ 5,469.84**			**$ 5,556.63**	**$86.79**	**1.6%**	**100.00%**

CNPI - FORT ERIE 2009 EDR
Bill Impacts May 2009 Compared To May 2008
Distribution Rates Calculated on the Basis of the Cost Allocation Informational Filing

Class	Consumption kWh	Consumption kW	May 2008 Bill	May 2009 Bill	Difference $	Bill Impact %	Max	Min
Residential	250		$ 44.37	$ 44.11	$ (0.26)	-0.6%	6.4%	-0.6%
	500		$ 65.21	$ 66.89	$ 1.68	2.6%		
Average Customer	671		$ 80.43	$ 83.38	$ 2.95	3.7%		
	1,000		$ 111.10	$ 116.59	$ 5.48	4.9%		
	1,250		$ 134.41	$ 141.82	$ 7.40	5.5%		
	1,500		$ 157.72	$ 167.05	$ 9.33	5.9%		
	2,000		$ 204.34	$ 217.51	$ 13.17	6.4%		
General Service Less Than 50 kW	1,000		$ 123.23	$ 127.23	$ 4.00	3.2%	3.2%	0.3%
	2,000		$ 232.90	$ 236.93	$ 4.03	1.7%		
Average Customer	2,657		$ 304.96	$ 309.01	$ 4.05	1.3%		
	4,000		$ 452.25	$ 456.34	$ 4.09	0.9%		
	6,000		$ 671.59	$ 675.74	$ 4.15	0.6%		
	10,000		$ 1,110.28	$ 1,114.56	$ 4.28	0.4%		
	15,000		$ 1,658.64	$ 1,663.08	$ 4.43	0.3%		
General Service 50 to 4,999 kW	25,000	50	$ 2,603.60	$ 2,664.74	$ 61.14	2.3%	2.3%	0.9%
	40,000	75	$ 4,028.73	$ 4,102.27	$ 73.54	1.8%		
	40,000	100	$ 4,328.24	$ 4,423.65	$ 95.40	2.2%		
Average Customer	83,747	226	$ 9,120.60	$ 9,298.62	$ 178.01	2.0%		
	125,000	250	$ 12,503.77	$ 12,676.77	$ 173.00	1.4%		
	250,000	500	$ 24,878.98	$ 25,191.82	$ 312.83	1.3%		
	1,500,000	2,500	$ 142,640.69	$ 143,914.64	$ 1,273.95	0.9%		
Unmetered Scattered Load	200		$ 30.12	$ 59.22	$ 29.10	96.6%	96.6%	25.3%
Average Connection	245		$ 34.60	$ 63.67	$ 29.07	84.0%		
	300		$ 40.07	$ 69.11	$ 29.04	72.5%		
	500		$ 59.99	$ 88.90	$ 28.91	48.2%		
	750		$ 85.22	$ 113.91	$ 28.69	33.7%		
	900		$ 101.63	$ 130.22	$ 28.59	28.1%		
	1,000		$ 112.58	$ 141.10	$ 28.52	25.3%		
Sentinel Lighting	300	1	$ 27.21	$ 29.42	$ 2.21	8.1%	9.7%	8.1%
	900	3	$ 85.23	$ 93.13	$ 7.90	9.3%		
	1,500	5	$ 149.65	$ 164.17	$ 14.52	9.7%		
	3,000	10	$ 308.42	$ 338.47	$ 30.06	9.7%		
	4,500	15	$ 464.89	$ 509.47	$ 44.58	9.6%		
Street Lighting	3,000	10	$ 289.80	$ 312.96	$ 23.17	8.0%	9.9%	7.8%
	4,500	15	$ 437.35	$ 471.90	$ 34.55	7.9%		
	6,000	20	$ 584.90	$ 630.83	$ 45.93	7.9%		
	30,000	100	$ 2,959.40	$ 3,191.07	$ 231.67	7.8%		
2873 Connections	172,000	491	$ 19,514.15	$ 21,449.36	$ 1,935.21	9.9%		

CNPI - Eastern Ontario Power
Bill Impacts May 2009 Compared To May 2008
Distribution Rates Calculated on the Basis of the Cost Allocation Informational Filing

Class	Consumption kWh	Consumption kW	May 2008 Bill	May 2009 Bill	Difference $	Bill Impact %	Max	Min
Residential	250		$ 39.67	$ 43.58	$ 3.91	9.9%	9.9%	9.1%
	500		$ 61.94	$ 68.03	$ 6.09	9.8%		
Average Customer	791		$ 90.20	$ 98.84	$ 8.64	9.6%		
	1,000		$ 110.93	$ 121.40	$ 10.47	9.4%		
	1,250		$ 135.73	$ 148.39	$ 12.66	9.3%		
	1,500		$ 160.53	$ 175.37	$ 14.84	9.2%		
	2,000		$ 210.13	$ 229.35	$ 19.22	9.1%		
General Service Less Than 50 kW	1,000		$ 134.49	$ 131.97	$ (2.52)	-1.9%	8.1%	-1.9%
	2,000		$ 241.30	$ 248.37	$ 7.07	2.9%		
Average Customer	2,807		$ 327.49	$ 342.30	$ 14.80	4.5%		
	4,000		$ 454.91	$ 481.15	$ 26.24	5.8%		
	6,000		$ 668.52	$ 713.94	$ 45.41	6.8%		
	10,000		$ 1,095.75	$ 1,179.51	$ 83.76	7.6%		
	15,000		$ 1,629.77	$ 1,761.47	$ 131.70	8.1%		
General Service 50 to 4,999 kW	25,000	50	$ 3,205.27	$ 2,814.10	$ (391.17)	-12.2%	7.7%	-12.2%
	40,000	75	$ 4,614.92	$ 4,352.08	$ (262.84)	-5.7%		
Average Customer	44,320	139	$ 5,426.17	$ 5,490.89	$ 64.72	1.2%		
	50,000	150	$ 5,970.90	$ 6,092.06	$ 121.16	2.0%		
	75,000	175	$ 8,201.41	$ 8,451.19	$ 249.78	3.0%		
	125,000	300	$ 13,197.55	$ 14,088.28	$ 890.73	6.7%		
	250,000	500	$ 24,885.21	$ 26,802.74	$ 1,917.53	7.7%		
Unmetered Scattered Load	250		$ 58.95	$ 64.78	$ 5.83	9.9%	9.9%	9.1%
	350		$ 68.61	$ 75.30	$ 6.68	9.7%		
	500		$ 83.12	$ 91.08	$ 7.96	9.6%		
	600		$ 92.78	$ 101.60	$ 8.82	9.5%		
	750		$ 107.79	$ 117.89	$ 10.10	9.4%		
Average Customer	985		$ 132.89	$ 145.00	$ 12.10	9.1%		
	1,000		$ 134.49	$ 146.73	$ 12.23	9.1%		
Sentinel Lighting	300	1	$ 29.13	$ 29.33	$ 0.20	0.7%	8.5%	0.7%
	900	3	$ 90.75	$ 98.28	$ 7.53	8.3%		
	1,500	5	$ 156.42	$ 169.38	$ 12.96	8.3%		
	3,000	10	$ 321.54	$ 348.67	$ 27.13	8.4%		
	4,500	15	$ 486.65	$ 527.96	$ 41.31	8.5%		
Street Lighting	3,000	10	$ 322.62	$ 331.53	$ 8.91	2.8%	2.8%	1.6%
	4,500	15	$ 486.41	$ 499.82	$ 13.41	2.8%		
	6,000	20	$ 650.20	$ 668.11	$ 17.90	2.8%		
	30,000	100	$ 3,287.62	$ 3,376.72	$ 89.10	2.7%		
557 Connections	46,000	129	$ 5,469.84	$ 5,556.63	$ 86.79	1.6%		

Harmonized Electricity Distribution Rates
Reconciliation of 2009 Revenue Requirement and 2009 Proposed Electricity Distribution Rates

	2009 Volumes			Proposed 2009 Rates		2009 Revenue			
Customer Class	No. of Customers / Connections	kWh	kW	Monthly Service Charge	Volumetric Charge	Monthly Service Charge	Volumetric Charge	Total Class Distribution Revenue	2009 Base Revenue Requirement
Residential	17,369	144,373,446		17.69	0.0150	3,686,985	2,165,602	5,852,587	5,852,901
General Service Less Than 50 kW	1,596	51,616,187		21.07	0.0228	403,406	1,176,849	1,580,255	1,581,936
General Service 50 to 4,999 kW	180	166,091,320	455,509	147.84	8.0620	319,334	3,672,313	3,991,647	3,991,622
Unmetered Scattered Load	28	439,961		36.39	0.0217	12,227	9,547	21,774	21,759
Sentinel Lighting	1,051	877,106	2,661	2.94	3.3290	37,079	8,860	45,939	45,905
Street Lighting	3,684	2,758,784	8,357	1.69	3.3000	74,712	27,578	102,289	102,139
	23,907	366,156,804	466,527			4,533,744	7,060,748	11,594,492	11,596,262
Less Transformer Allowance Add Back									
						Difference			(1,770)

Canadian Niagara Power – Fort Erie
TARIFF OF RATES AND CHARGES
Effective May 1, 2009

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	17.96
Service Charge Rate Rider for Storm Damage Cost Recovery – effective until August 31, 2009	$	2.11
Distribution Volumetric Rate	$/kWh	0.0150
Distribution Volumetric Rate Rider for Storm Damage Cost Recovery – effective until August 31, 2009	$/kWh	0.0008
Regulatory Asset Recovery	$/kWh	0.0002
Retail Transmission Rate – Network Service Rate	$/kWh	0.0044
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

General Service Less than 50 kW

Service Charge	$	21.34
Service Charge Rate Rider for Storm Damage Cost Recovery – effective until August 31, 2009	$	1.85
Distribution Volumetric Rate	$/kWh	0.0228
Distribution Volumetric Rate Rider for Storm Damage Cost Recovery – effective until August 31, 2009	$/kWh	0.0024
Regulatory Asset Recovery	$/kWh	0.0001
Retail Transmission Rate – Network Service Rate	$/kWh	0.0040
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0040
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

General Service 50 to 4,999 kW

Service Charge	$	148.11
Service Charge Rate Rider for Storm Damage Cost Recovery – effective until August 31, 2009	$	12.42
Distribution Volumetric Rate	$/kW	8.062
Distribution Volumetric Rate Rider for Storm Damage Cost Recovery – effective until August 31, 2009	$/kW	0.7737
Regulatory Asset Recovery	$/kW	0.0391
Retail Transmission Rate – Network Service Rate	$/kW	1.6442
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.5973
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge (per customer)	$	36.39
Service Charge (per customer) Rate Rider for Storm Damage Cost Recovery – effective until August 31, 2009	$	0.91
Distribution Volumetric	$/kWh	0.0217
Distribution Volumetric Rate Rider for Storm Damage Cost Recovery – effective until August 31, 2009	$/kWh	0.0024
Regulatory Asset Recovery	$/kWh	0.0003
Retail Transmission Rate – Network Service Rate	$/kWh	0.0040

Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0040
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Sentinel Lighting

Service Charge	$	2.94
Service Charge Rate Rider for Storm Damage Cost Recovery – effective until August 31, 2009	$	0.21
Distribution Volumetric Rate	$/kW	3.329
Distribution Volumetric Rate Rider for Storm Damage Cost Recovery – effective until August 31, 2009	$/kW	0.2105
Regulatory Asset Recovery	$/kW	0.0574
Retail Transmission Rate – Network Service Rate	$/kW	1.3124
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2607
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Street Lighting

Service Charge (per connection)	$	1.69
Service Charge (per connection) Rate Rider for Storm Damage Cost Recovery – effective until August 31, 2009	$	0.14
Distribution Volumetric Rate	$/kW	3.300
Distribution Volumetric Rate Rider for Storm Damage Cost Recovery – effective until August 31, 2009	$/kW	0.1691
Regulatory Asset Recovery	$/kW	0.0445
Retail Transmission Rate – Network Service Rate	$/kW	1.2400
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2348
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Specific Service Charges

Customer Administration		
Arrears Certificate	$	15.00
Statement of Account	$	15.00
Pulling Post Dated Cheques	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement Letter	$	15.00
Income tax letter	$	15.00
Notification Charge	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Returned cheque (plus bank charges)	$	15.00
Charge to certify cheques	$	15.00
Legal letter charge	$	15.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection – during regular hours	$	30.00
Collection of account charge – no disconnect – after regular hours	$	165.00
Disconnect/Reconnect Charges at meter - during regular hours	$	65.00
Disconnect/Reconnect Charges at meter - after regular hours	$	185.00
Disconnect/reconnect at pole – during regular hours	$	185.00

Disconnect/reconnect at pole – after regular hours	$	415.00
Install/remove load control device – during regular hours	$	65.00
Install/remove load control device – after regular hours	$	185.00
Service call – customer-owned equipment	$	30.00
Service call – after regular hours	$	165.00
Temporary service install & remove – overhead – no transformer	$	500.00
Temporary service install & remove – underground – no transformer	$	300.00
Temporary service install & remove – overhead – with transformer	$	1,000.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35

Allowances

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

Retail Service Charges (if applicable)

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly fixed charge per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing charge, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50

Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party

Up to twice a year		no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

Loss Factors

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0391
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0287

Canadian Niagara Power – Eastern Ontario Power
TARIFF OF RATES AND CHARGES
Effective May 1, 2009

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	17.96
Distribution Volumetric Rate	$/kWh	0.0154
Regulatory Asset Recovery	$/kWh	0.0002
Retail Transmission Rate – Network Service Rate	$/kWh	0.0043
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0041
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

General Service Less than 50 kW

Service Charge	$	21.34
Distribution Volumetric Rate	$/kWh	0.0243
Regulatory Asset Recovery	$/kWh	0.0002
Retail Transmission Rate-Network Service Rate	$/kWh	0.0039
Retail Transmission Rate-Line and Transformation Connection Service Rate	$/kWh	0.0037
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

General Service 50 to 4,999 kW

Service Charge	$	148.11
Distribution Volumetric Rate	$/kW	8.1769
Regulatory Asset Recovery	$/kW	0.0656
Retail Transmission Rate - Network Service Rate	$/kW	1.6231
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.5725
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge (per customer)	$	36.39
Distribution Volumetric Rate	$/kWh	0.0232
Regulatory Asset Recovery	$/kWh	0.0003
Retail Transmission Rate – Network Service Rate	$/kWh	0.0039
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0037
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Sentinel Lighting

Service Charge	$	2.94
Distribution Volumetric Rate	$/kW	3.3822
Regulatory Asset Recovery	$/kW	0.0727
Retail Transmission Rate – Network Service Rate	$/kW	1.1972
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.1635
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Street Lighting

Service Charge (per connection)	$	1.69
Distribution Volumetric Rate	$/kW	3.3232
Regulatory Asset Recovery	$/kW	0.0687
Retail Transmission Rate – Network Service Rate	$/kW	1.1911
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.1396
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Specific Service Charges

Customer Administration		
Arrears Certificate	$	15.00
Statement of Account	$	15.00
Pulling Post Dated Cheques	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement Letter	$	15.00
Income tax letter	$	15.00
Notification Charge	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Returned cheque (plus bank charges)	$	15.00
Charge to certify cheques	$	15.00
Legal letter charge	$	15.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection – during regular hours	$	30.00
Collection of account charge – no disconnection – after regular hours	$	165.00
Disconnect/Reconnect Charges at meter - during regular hours	$	65.00
Disconnect/Reconnect Charges at meter - after regular hours	$	185.00
Disconnect/reconnect at pole – during regular hours	$	185.00
Disconnect/reconnect at pole – after regular hours	$	415.00
Install/remove load control device – during regular hours	$	65.00
Install/remove load control device – after regular hours	$	185.00
Service call – customer-owned equipment	$	30.00
Service call – after regular hours	$	165.00
Temporary service install & remove – overhead – no transformer	$	500.00
Temporary service install & remove – underground – no transformer	$	300.00
Temporary service install & remove – overhead – with transformer	$	1,000.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35

Allowances

Transformer Allowance for Ownership - per kW of billing demand/month	/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

Retail Service Charges (if applicable)

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly fixed charge per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing charge, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50

Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party

Up to twice a year		no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0719
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0612

RECONCILIATION OF RATE CLASS REVENUE TO BASE REVENUE REQUIREMENT

The following is a reconciliation of the anticipated distribution revenue derived from the proposed harmonized electricity distribution rates together with forecasted customer and load data as proposed in this Application compared to the Base Revenue Requirement determined for 2009 Test Year.

Reconciliation of Rate Class Revenue Base Revenue Requirement

Customer Class	Forecasted Revenue			Base Revenue Requirement $
	Monthly Service Charge $	Volumetric Service Charge $	Total $	
Residential	3,686,985	2,165,602	5,852,587	5,852,901
GS < 50 kW	403,406	1,176,849	1,580,255	1,581,936
GS 50 – 4,999 kW	319,334	3,672,313	3,991,647	3,991,622
Unmetered Scattered Load	12,227	9,547	21,774	21,759
Sentinel Lighting	37,079	8,860	45,939	45,905
Street Lighting	74,712	27,578	102,289	102,139
Total	4,533,744	7,060,748	11,594,492	11,596,262

The variation between the forecast revenue and the Base Revenue Requirement for the test year is due to rounding.

This calculation is provided in more detail in the Rate Design Model, Exhibit 10, Tab 1, Schedule 3, Appendix A.

2009 EDR RATE AND BILL IMPACTS FORT ERIE

In this Application, CNPI – Gananoque is proposing 2009 electricity distribution rates that are both just and reasonable with rate stability and predictability as guiding principles. The rates are calculated on the cost of service methodology and are harmonized with the distribution rates in Gananoque.

The rates are designed respecting the Board's guidelines with the ultimate goal being to achieve a class unity revenue-to-cost ratio. The Board has provided guidelines for rate design in the form of a range for the individual class revenue-to-cost ratio and CNPI has applied those ranges to the unity revenue-to-cost ratio as determined by the combined Cost Allocation Informational Filing for Fort Erie and Gananoque. In its rate design, CNPI has attempted to move customer revenue-to-cost class ratios into these ranges while respecting the relative rate impact to the customer class and where necessary for rate mitigation (total bill impact of 10% or less) the design has remained outside the range specified in the guidelines.

The 2009 electricity distribution rate impacts and total bill impacts are summarized in the following tables.

CNPI - FORT ERIE 2009 EDR
Rate Impacts May 2009 Compared To May 2008
Distribution Rates Calculated on the Basis of the Cost Allocational Informational Filing

Residential

Consumption	1,000	kWh	0	kW	Loss Factor 1.0391

	May 2008 BILL			May 2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Energy First Tier (kWh)	600	$ 0.0530	$ 31.80	600	$ 0.0530	$ 31.80	$0.00	0.0%	27.28%
Energy Second Tier (kWh)	448	$ 0.0620	$ 27.77	439	$ 0.0620	$ 27.22	($0.55)	(2.0)%	23.35%
Sub-Total: Energy			**$ 59.57**			**$ 59.02**	**($0.55)**	**(0.9)%**	**50.63%**
Monthly Service Charge	1	$ 20.06	$ 20.06	1	$ 17.96	$ 17.96	($2.10)	(10.5)%	15.40%
Distribution (kWh)	1,000	$ 0.0072	$ 7.20	1,000	$ 0.0150	$ 15.00	$7.80	108.3%	12.87%
Distribution (kW)	0	$ -	$ -	0	$ -	$ -	$0.00	0.0%	0.00%
Regulatory Assets (kWh)	1,000	$ -	$ -	1,000	$ 0.0002	$ 0.20	$0.20	0.0%	0.17%
Rate Riders	1,000	$ -	$ -	1,000	$ -	$ -	$0.00	0.0%	0.00%
Monthly Rate Rider Adjustment Z-Factor	1	$ 2.11	$ 2.11	1	$ 2.11	$ 2.11	$0.00	0.0%	1.81%
Volumetric Rate Rider Adjustment Z-Factor	1,000	$ 0.0008	$ 0.80	1,000	$ 0.0008	$ 0.80	$0.00	0.0%	0.69%
Retail Transmission Rate – Network Service Rate	1,048	$ 0.0044	$ 4.61	1,039	$ 0.0044	$ 4.57	($0.04)	(0.8)%	3.92%
Retail Transmission Rate – Line and Transformation Connection Service Rate	1,048	$ 0.0045	$ 4.72	1,039	$ 0.0045	$ 4.68	($0.04)	(0.8)%	4.01%
Sub-Total: Delivery			**$ 39.50**			**$ 45.32**	**$5.82**	**14.7%**	**38.87%**
Wholesale Market Service Rate	1,048	$ 0.0052	$ 5.45	1039	$ 0.0052	$ 5.40	($0.05)	(0.8)%	4.63%
Rural Rate Protection Charge	1,048	$ 0.0010	$ 1.05	1039	$ 0.0010	$ 1.04	($0.01)	(0.8)%	0.89%
Regulated Price Plan – Administration Charge	1	$ 0.2500	$ 0.25	1	$ 0.2500	$ 0.25	$0.00	0.0%	0.21%
Sub-Total: Regulatory			**$ 6.75**			**$ 6.69**	**($0.05)**	**(0.8)%**	**5.74%**
Debt Retirement Charge (DRC)	1,000	$ -	**$ -**	1,000	$ -	**$ -**	**$0.00**	**0.0%**	**0.0%**
Total Bill before Taxes			**$ 105.81**			**$ 111.03**	**$5.22**	**4.9%**	**95.24%**
GST	$ 105.81	5%	**$ 5.29**	$ 111.03	5%	**$ 5.55**	**$0.26**	**4.9%**	**4.76%**
Total Bill after Taxes			**$ 111.10**			**$ 116.59**	**$5.48**	**4.9%**	**100.00%**

General Service Less Than 50 kW

Consumption	2,000	kWh	0	kW	Loss Factor 1.0391

	May 2008 BILL			May 2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Energy First Tier (kWh)	750	$ 0.0530	$ 39.75	750	$ 0.0530	$ 39.75	$0.00	0.0%	16.78%
Energy Second Tier (kWh)	1,346	$ 0.0620	$ 83.44	1,328	$ 0.0620	$ 82.35	($1.09)	(1.3)%	34.76%
Sub-Total: Energy			**$ 123.19**			**$ 122.10**	**($1.09)**	**(0.9)%**	**51.53%**
Monthly Service Charge	1	$ 17.56	$ 17.56	1	$ 21.34	$ 21.34	$3.78	21.5%	9.01%
Distribution (kWh)	2,000	$ 0.0222	$ 44.40	2,000	$ 0.0228	$ 45.60	$1.20	2.7%	19.25%
Distribution (kW)	0	$ -	$ -	0	$ -	$ -	$0.00	0.0%	0.00%
Regulatory Assets (kWh)	2,000	$ -	$ -	2,000	$ 0.0001	$ 0.20	$0.20	0.0%	0.08%
Rate Riders	2,000	$ -	$ -	2,000	$ -	$ -	$0.00	0.0%	0.00%
Monthly Rate Rider Adjustment Z-Factor	1	$ 1.85	$ 1.85	1	$ 1.85	$ 1.85	$0.00	0.0%	0.78%
Volumetric Rate Rider Adjustment Z-Factor	2,000	$ 0.0024	$ 4.80	2,000	$ 0.0024	$ 4.80	$0.00	0.0%	2.03%
Retail Transmission Rate – Network Service Rate	2,096	$ 0.0040	$ 8.38	2,078	$ 0.0040	$ 8.31	($0.07)	(0.8)%	3.51%
Retail Transmission Rate – Line and Transformation Connection Service Rate	2,096	$ 0.0040	$ 8.38	2,078	$ 0.0040	$ 8.31	($0.07)	(0.8)%	3.51%
Sub-Total: Delivery			**$ 85.38**			**$ 90.42**	**$5.04**	**5.9%**	**38.16%**
Wholesale Market Service Rate	2,096	$ 0.0052	$ 10.90	2,078	$ 0.0052	$ 10.81	($0.09)	(0.8)%	4.56%
Rural Rate Protection Charge	2,096	$ 0.0010	$ 2.10	2,078	$ 0.0010	$ 2.08	($0.02)	(0.8)%	0.88%
Regulated Price Plan – Administration Charge	1	$ 0.2500	$ 0.25	1	$ 0.2500	$ 0.25	$0.00	0.0%	0.11%
Sub-Total: Regulatory			**$ 13.24**			**$ 13.13**	**($0.11)**	**(0.8)%**	**5.54%**
Debt Retirement Charge (DRC)	2,000	$ -	**$ -**	2,000	$ -	**$ -**	**$0.00**	**0.0%**	**0.00%**
Total Bill before Taxes			**$ 221.81**			**$ 225.65**	**$3.84**	**1.7%**	**95.24%**
GST	$ 221.81	5%	**$ 11.09**	$ 225.65	5%	**$ 11.28**	**$0.19**	**1.7%**	**4.76%**
Total Bill after Taxes			**$ 232.90**			**$ 236.93**	**$4.03**	**1.7%**	**100.00%**

General Service 50 to 4,999 kW

Consumption	83,747	kWh	226	kW	***Loss Factor 1.0391***

	May 2008 BILL			May 2009 BILL			IMPACT		
	Volume	**RATE $**	**CHARGE $**	**Volume**	**RATE $**	**CHARGE $**	**$**	**%**	**% of Total Bill**
Energy First Tier (kWh)	750	$ 0.0530	$ 39.75	750	$ 0.0530	$ 39.75	$0.00	0.0%	0.43%
Energy Second Tier (kWh)	87,008	$ 0.0620	$ 5,394.53	86,272	$ 0.0620	$ 5,348.83	($45.69)	(0.8)%	57.52%
Sub-Total: Energy			**$ 5,434.28**			**$ 5,388.58**	**($45.69)**	**(0.8)%**	**57.95%**
Monthly Service Charge	1	$ 116.52	$ 116.52	1	$ 148.11	$ 148.11	$31.59	27.1%	1.59%
Distribution (kWh)	83,747	$ -	$ -	83,747	$ -	$ -	$0.00	0.0%	0.00%
Distribution (kW)	226	$ 7.2398	$ 1,636.19	226	$ 8.0620	$ 1,822.01	$185.82	11.4%	19.59%
Regulatory Assets (kW)	226	$ -	$ -	226	$ 0.0391	$ 8.84	$8.84	0.0%	0.10%
Rate Riders	226	$ -	$ -	226	$ -	$ -	$0.00	0.0%	0.00%
Monthly Rate Rider Adjustment Z-Factor	1	$ 12.42	$ 12.42	1	$ 12.42	$ 12.42	$0.00	0.0%	0.13%
Volumetric Rate Rider Adjustment Z-Factor	226	$ 0.7737	$ 174.86	226	$ 0.7737	$ 174.86	$0.00	0.0%	1.88%
Retail Transmission Rate – Network Service Rate	237	$ 1.6442	$ 389.39	235	$ 1.6442	$ 386.12	($3.27)	(0.8)%	4.15%
Retail Transmission Rate – Line and Transformation Connection Service Rate	237	$ 1.5973	$ 378.28	235	$ 1.5973	$ 375.10	($3.18)	(0.8)%	4.03%
Sub-Total: Delivery			**$ 2,707.66**			**$ 2,927.46**	**$219.80**	**8.1%**	**31.48%**
Wholesale Market Service Rate	87,758	$ 0.0052	$ 456.34	87022	$ 0.0052	$ 452.51	($3.83)	(0.8)%	4.87%
Rural Rate Protection Charge	87,758	$ 0.0010	$ 87.76	87022	$ 0.0010	$ 87.02	($0.74)	(0.8)%	0.94%
Regulated Price Plan – Administration Charge	1	$ 0.2500	$ 0.25	1	$ 0.2500	$ 0.25	$0.00	0.0%	0.00%
Sub-Total: Regulatory			**$ 544.35**			**$ 539.78**	**($4.57)**	**(0.8)%**	**5.80%**
Debt Retirement Charge (DRC)	83,747	$ -	**$ -**	83,747	$ -	**$ -**	**$0.00**	**0.0%**	**0.00%**
Total Bill before Taxes			**$ 8,686.29**			**$ 8,855.82**	**$169.54**	**2.0%**	**95.24%**
GST	$ 8,686.29	5%	**$ 434.31**	$ 8,855.82	5%	**$ 442.79**	**$8.48**	**2.0%**	**4.76%**
Total Bill after Taxes			**$ 9,120.60**			**$ 9,298.62**	**$178.01**	**2.0%**	**100.00%**

Unmetered Scattered Load

Consumption	750	kWh	0	kW	***Loss Factor 1.0391***

	May 2008 BILL			May 2009 BILL			IMPACT		
	Volume	**RATE $**	**CHARGE $**	**Volume**	**RATE $**	**CHARGE $**	**$**	**%**	**% of Total Bill**
Energy First Tier (kWh)	750	$ 0.0530	$ 39.75	750	$ 0.0530	$ 39.75	$0.00	0.0%	34.90%
Energy Second Tier (kWh)	36	$ 0.0620	$ 2.23	29	$ 0.0620	$ 1.82	($0.41)	(18.4)%	1.60%
Sub-Total: Energy			**$ 41.98**			**$ 41.57**	**($0.41)**	**(1.0)%**	**36.49%**
Monthly Service Charge	1	$ 8.56	$ 8.56	1	$ 36.39	$ 36.39	$27.83	325.1%	31.95%
Distribution (kWh)	750	$ 0.0220	$ 16.50	750	$ 0.0217	$ 16.28	($0.22)	(1.4)%	14.29%
Distribution (kW)	0	$ -	$ -	0	$ -	$ -	$0.00	0.0%	0.00%
Regulatory Assets (kWh)	750	$ -	$ -	750	$ 0.0003	$ 0.23	$0.23	0.0%	0.20%
Rate Riders	750	$ -	$ -	750	$ -	$ -	$0.00	0.0%	0.00%
Monthly Rate Rider Adjustment Z-Factor	1	$ 0.91	$ 0.91	1	$ 0.91	$ 0.91	$0.00	0.0%	0.80%
Volumetric Rate Rider Adjustment Z-Factor	750	$ 0.0024	$ 1.80	750	$ 0.0024	$ 1.80	$0.00	0.0%	1.58%
Retail Transmission Rate – Network Service Rate	786	$ 0.0040	$ 3.14	779	$ 0.0040	$ 3.12	($0.03)	(0.8)%	2.74%
Retail Transmission Rate – Line and Transformation Connection Service Rate	786	$ 0.0040	$ 3.14	779	$ 0.0040	$ 3.12	($0.03)	(0.8)%	2.74%
Sub-Total: Delivery			**$ 34.06**			**$ 61.83**	**$27.78**	**81.6%**	**54.28%**
Wholesale Market Service Rate	786	$ 0.0052	$ 4.09	779	$ 0.0052	$ 4.05	($0.03)	(0.8)%	3.56%
Rural Rate Protection Charge	786	$ 0.0010	$ 0.79	779	$ 0.0010	$ 0.78	($0.01)	(0.8)%	0.68%
Regulated Price Plan – Administration Charge	1	$ 0.2500	$ 0.25	1	$ 0.2500	$ 0.25	$0.00	0.0%	0.22%
Sub-Total: Regulatory			**$ 5.12**			**$ 5.08**	**($0.04)**	**(0.8)%**	**4.46%**
Debt Retirement Charge (DRC)	750	$ -	**$ -**	750	$ -	**$ -**	**$0.00**	**0.0%**	**0.00%**
Total Bill before Taxes			**$ 81.16**			**$ 108.48**	**$27.33**	**33.7%**	**95.24%**
GST	$ 81.16	5%	**$ 4.06**	$ 108.48	5%	**$ 5.42**	**$1.37**	**33.7%**	**4.76%**
Total Bill after Taxes			**$ 85.22**			**$ 113.91**	**$28.69**	**33.7%**	**100.00%**

Sentinel Lighting

Consumption	3,000	kWh	10	kW	Loss Factor 1.0391

	May 2008 BILL			May 2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Energy First Tier (kWh)	750	$ 0.0530	$ 39.75	750	$ 0.0530	$ 39.75	$0.00	0.0%	11.74%
Energy Second Tier (kWh)	2,394	$ 0.0620	$ 148.41	2,367	$ 0.0620	$ 146.77	($1.64)	(1.1)%	43.36%
Sub-Total: Energy			**$ 188.16**			**$ 186.52**	**($1.64)**	**(0.9)%**	**55.11%**
Monthly Service Charge	17	$ 1.97	$ 33.49	17	$ 2.94	$ 49.98	$16.49	49.2%	14.77%
Distribution (kWh)	3,000	$ -	$ -	3,000	$ -	$ -	$0.00	0.0%	0.00%
Distribution (kW)	10	$ 1.9700	$ 19.70	10	$ 3.3290	$ 33.29	$13.59	69.0%	9.84%
Regulatory Assets (kWh)	10	$ -	$ -	10	$ 0.0574	$ 0.57	$0.57	0.0%	0.17%
Rate Riders	10	$ -	$ -	10	$ -	$ -	$0.00	0.0%	0.00%
Monthly Rate Rider Adjustment Z-Factor	17	$ 0.21	$ 3.57	17	$ 0.21	$ 3.57	$0.00	0.0%	1.05%
Volumetric Rate Rider Adjustment Z-Factor	10	$ 0.2105	$ 2.11	10	$ 0.2105	$ 2.11	$0.00	0.0%	0.62%
Retail Transmission Rate – Network Service Rate	10	$ 1.3124	$ 13.75	10	$ 1.3124	$ 13.64	($0.12)	(0.8)%	4.03%
Retail Transmission Rate – Line and Transformation Connection Service Rate	10	$ 1.2607	$ 13.21	10	$ 1.2607	$ 13.10	($0.11)	(0.8)%	3.87%
Sub-Total: Delivery			**$ 85.83**			**$ 116.26**	**$30.43**	**35.5%**	**34.35%**
Wholesale Market Service Rate	3,144	$ 0.0052	$ 16.35	3,117	$ 0.0052	$ 16.21	($0.14)	(0.8)%	4.79%
Rural Rate Protection Charge	3,144	$ 0.0010	$ 3.14	3,117	$ 0.0010	$ 3.12	($0.03)	(0.8)%	0.92%
Regulated Price Plan – Administration Charge	1	$ 0.2500	$ 0.25	1	$ 0.2500	$ 0.25	$0.00	0.0%	0.07%
Sub-Total: Regulatory			**$ 19.74**			**$ 19.58**	**($0.16)**	**(0.8)%**	**5.78%**
Debt Retirement Charge (DRC)	3,000	$ -	**$ -**	3,000	$ -	**$ -**	**$0.00**	**0.0%**	**0.00%**
Total Bill before Taxes			**$ 293.73**			**$ 322.36**	**$28.63**	**9.7%**	**95.24%**
GST	$ 293.73	5%	**$ 14.69**	$ 322.36	5%	**$ 16.12**	**$1.43**	**9.7%**	**4.76%**
Total Bill after Taxes			**$ 308.42**			**$ 338.47**	**$30.06**	**9.7%**	**100.00%**

Street Lighting

Consumption	172,000	kWh	491	kW	Loss Factor 1.0391

	May 2008 BILL			May 2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Energy First Tier (kWh)	750	$ 0.0530	$ 39.75	750	$ 0.0530	$ 39.75	$0.00	0.0%	0.19%
Energy Second Tier (kWh)	179,489	$ 0.0620	$ 11,128.31	177,975	$ 0.0620	$ 11,034.46	($93.84)	(0.8)%	51.44%
Sub-Total: Energy			**$ 11,168.06**			**$ 11,074.21**	**($93.84)**	**(0.8)%**	**51.63%**
Monthly Service Charge	2873	$ 1.31	$ 3,763.63	2873	$ 1.69	$ 4,855.37	$1,091.74	29.0%	22.64%
Distribution (kWh)	172,000	$ -	$ -	172,000	$ -	$ -	$0.00	0.0%	0.00%
Distribution (kW)	491	$ 1.5823	$ 776.91	491	$ 3.3000	$ 1,620.30	$843.39	108.6%	7.55%
Regulatory Assets (kWh)	491	$ -	$ -	491	$ 0.0445	$ 21.85	$21.85	0.0%	0.10%
Rate Riders	491	$ -	$ -	491	$ -	$ -	$0.00	0.0%	0.00%
Monthly Rate Rider Adjustment Z-Factor	2873	$ 0.14	$ 402.22	2873	$ 0.14	$ 402.22	$0.00	0.0%	1.88%
Volumetric Rate Rider Adjustment Z-Factor	491	$ 0.1691	$ 83.03	491	$ 0.1691	$ 83.03	$0.00	0.0%	0.39%
Retail Transmission Rate – Network Service Rate	515	$ 1.2400	$ 638.00	510	$ 1.2400	$ 632.65	($5.36)	(0.8)%	2.95%
Retail Transmission Rate – Line and Transformation Connection Service Rate	515	$ 1.2348	$ 635.33	510	$ 1.2348	$ 629.99	($5.34)	(0.8)%	2.94%
Sub-Total: Delivery			**$ 6,299.12**			**$ 8,245.41**	**$1,946.29**	**30.9%**	**38.44%**
Wholesale Market Service Rate	180239	$ 0.0052	$ 937.24	178725	$ 0.0052	$ 929.37	($7.87)	(0.8)%	4.33%
Rural Rate Protection Charge	180239	$ 0.0010	$ 180.24	178725	$ 0.0010	$ 178.73	($1.51)	(0.8)%	0.83%
Regulated Price Plan – Administration Charge	1	$ 0.2500	$ 0.25	1	$ 0.2500	$ 0.25	$0.00	0.0%	0.00%
Sub-Total: Regulatory			**$ 1,117.73**			**$ 1,108.35**	**($9.38)**	**(0.8)%**	**5.17%**
Debt Retirement Charge (DRC)	172,000	$ -	**$ -**	172,000	$ -	**$ -**	**$0.00**	**0.0%**	**0.00%**
Total Bill before Taxes			**$ 18,584.90**			**$ 20,427.96**	**$1,843.06**	**9.9%**	**95.24%**
GST	$ 18,584.90	5%	**$ 929.25**	$ 20,427.96	5%	**$ 1,021.40**	**$92.15**	**9.9%**	**4.76%**
Total Bill after Taxes			**$ 19,514.15**			**$ 21,449.36**	**$1,935.21**	**9.9%**	**100.00%**

CNPI - FORT ERIE 2009 EDR
Bill Impacts May 2009 Compared To May 2008
Distribution Rates Calculated on the Basis of the Cost Allocation Informational Filing

Class	Consumption kWh	Consumption kW	May 2008 Bill	May 2009 Bill	Difference $	Bill Impact %	Max	Min
Residential	250		$ 44.37	$ 44.11	$ (0.26)	-0.6%	6.4%	-0.6%
	500		$ 65.21	$ 66.89	$ 1.68	2.6%		
Average Customer	671		$ 80.43	$ 83.38	$ 2.95	3.7%		
	1,000		$ 111.10	$ 116.59	$ 5.48	4.9%		
	1,250		$ 134.41	$ 141.82	$ 7.40	5.5%		
	1,500		$ 157.72	$ 167.05	$ 9.33	5.9%		
	2,000		$ 204.34	$ 217.51	$ 13.17	6.4%		
General Service Less Than 50 kW	1,000		$ 123.23	$ 127.23	$ 4.00	3.2%	3.2%	0.3%
	2,000		$ 232.90	$ 236.93	$ 4.03	1.7%		
Average Customer	2,657		$ 304.96	$ 309.01	$ 4.05	1.3%		
	4,000		$ 452.25	$ 456.34	$ 4.09	0.9%		
	6,000		$ 671.59	$ 675.74	$ 4.15	0.6%		
	10,000		$ 1,110.28	$ 1,114.56	$ 4.28	0.4%		
	15,000		$ 1,658.64	$ 1,663.08	$ 4.43	0.3%		
General Service 50 to 4,999 kW	25,000	50	$ 2,603.60	$ 2,664.74	$ 61.14	2.3%	2.3%	0.9%
	40,000	75	$ 4,028.73	$ 4,102.27	$ 73.54	1.8%		
	40,000	100	$ 4,328.24	$ 4,423.65	$ 95.40	2.2%		
Average Customer	83,747	226	$ 9,120.60	$ 9,298.62	$ 178.01	2.0%		
	125,000	250	$ 12,503.77	$ 12,676.77	$ 173.00	1.4%		
	250,000	500	$ 24,878.98	$ 25,191.82	$ 312.83	1.3%		
	1,500,000	2,500	$ 142,640.69	$ 143,914.64	$ 1,273.95	0.9%		
Unmetered Scattered Load	200		$ 30.12	$ 59.22	$ 29.10	96.6%	96.6%	25.3%
Average Connection	245		$ 34.60	$ 63.67	$ 29.07	84.0%		
	300		$ 40.07	$ 69.11	$ 29.04	72.5%		
	500		$ 59.99	$ 88.90	$ 28.91	48.2%		
	750		$ 85.22	$ 113.91	$ 28.69	33.7%		
	900		$ 101.63	$ 130.22	$ 28.59	28.1%		
	1,000		$ 112.58	$ 141.10	$ 28.52	25.3%		
Sentinel Lighting	300	1	$ 27.21	$ 29.42	$ 2.21	8.1%	9.7%	8.1%
	900	3	$ 85.23	$ 93.13	$ 7.90	9.3%		
	1,500	5	$ 149.65	$ 164.17	$ 14.52	9.7%		
	3,000	10	$ 308.42	$ 338.47	$ 30.06	9.7%		
	4,500	15	$ 464.89	$ 509.47	$ 44.58	9.6%		
Street Lighting	3,000	10	$ 289.80	$ 312.96	$ 23.17	8.0%	9.9%	7.8%
	4,500	15	$ 437.35	$ 471.90	$ 34.55	7.9%		
	6,000	20	$ 584.90	$ 630.83	$ 45.93	7.9%		
	30,000	100	$ 2,959.40	$ 3,191.07	$ 231.67	7.8%		
2873 Connections	172,000	491	$ 19,514.15	$ 21,449.36	$ 1,935.21	9.9%		

2009 EDR RATE AND BILL IMPACTS GANANOQUE

In this Application, CNPI – Gananoque is proposing 2009 electricity distribution rates that are both just and reasonable with rate stability and predictability as guiding principles. The rates are calculated on the cost of service methodology and are harmonized with the distribution rates in Fort Erie.

The rates are designed respecting the Board's guidelines with the ultimate goal being to achieve a class unity revenue-to-cost ratio. The Board has provided guidelines for rate design in the form of a range for the individual class revenue-to-cost ratio and CNPI has applied those ranges to the unity revenue-to-cost ratio as determined by the combined Cost Allocation Informational Filing for Fort Erie and Gananoque. In its rate design, CNPI has attempted to move customer revenue-to-cost class ratios into these ranges while respecting the relative rate impact to the customer class and where necessary for rate mitigation (total bill impact of 10% or less) the design has remained outside the range specified in the guidelines.

The 2009 electricity distribution rate impacts and total bill impacts are summarized in the following tables.

CNPI - Eastern Ontario Power 2009 EDR
Rate Impacts May 2009 Compared To May 2008
Distribution Rates Calculated on the Basis of the Cost Allocational Informational Filing

Residential

Consumption	1,000	kWh	0	kW	Loss Factor 1.0719

	May 2008 BILL			May 2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Energy First Tier (kWh)	600	$ 0.0530	$ 31.80	600	$ 0.0530	$ 31.80	$0.00	0.0%	26.19%
Energy Second Tier (kWh)	472	$ 0.0620	$ 29.23	472	$ 0.0620	$ 29.26	$0.02	0.1%	24.10%
Sub-Total: Energy			**$ 61.03**			**$ 61.06**	**$0.02**	**0.0%**	**50.30%**
Monthly Service Charge	1	$ 16.32	$ 16.32	1	$ 17.96	$ 17.96	$1.64	10.0%	14.79%
Distribution (kWh)	1,000	$ 0.0073	$ 7.30	1,000	$ 0.0154	$ 15.40	$8.10	111.0%	12.69%
Distribution (kW)	0	$ -	$ -	0	$ -	$ -	$0.00	0.0%	0.00%
Regulatory Assets (kWh)	1,000	$ -	$ -	1,000	$ 0.0002	$ 0.20	$0.20	0.0%	0.16%
Rate Riders	1,000	$ -	$ -	1,000	$ -	$ -	$0.00	0.0%	0.00%
Monthly Rate Rider Adjustment Z-Factor	1	$ -	$ -	1	$ -	$ -	$0.00	0.0%	0.00%
Volumetric Rate Rider Adjustment Z-Factor	1,000	$ -	$ -	1,000	$ -	$ -	$0.00	0.0%	0.00%
Retail Transmission Rate – Network Service Rate	1,072	$ 0.0043	$ 4.61	1,072	$ 0.0043	$ 4.61	$0.00	0.0%	3.80%
Retail Transmission Rate – Line and Transformation Connection Service Rate	1,072	$ 0.0041	$ 4.39	1,072	$ 0.0041	$ 4.39	$0.00	0.0%	3.62%
Sub-Total: Delivery			**$ 32.62**			**$ 42.56**	**$9.94**	**30.5%**	**35.06%**
Wholesale Market Service Rate	1,072	$ 0.0052	$ 5.57	1,072	$ 0.0052	$ 5.57	$0.00	0.0%	4.59%
Rural Rate Protection Charge	1,072	$ 0.0010	$ 1.07	1,072	$ 0.0010	$ 1.07	$0.00	0.0%	0.88%
Regulated Price Plan – Administration Charge	1	$ 0.2500	$ 0.25	1	$ 0.2500	$ 0.25	$0.00	0.0%	0.21%
Sub-Total: Regulatory			**$ 6.89**			**$ 6.90**	**$0.00**	**0.0%**	**5.68%**
Debt Retirement Charge (DRC)	1,000	$ 0.0051	**$ 5.10**	1,000	$ 0.0051	**$ 5.10**	**$0.00**	**0.0%**	**4.2%**
Total Bill before Taxes			**$ 105.65**			**$ 115.62**	**$9.97**	**9.4%**	**95.24%**
GST	$ 105.65	5%	**$ 5.28**	$ 115.62	5%	**$ 5.78**	**$0.50**	**9.4%**	**4.76%**
Total Bill after Taxes			**$ 110.93**			**$ 121.40**	**$10.47**	**9.4%**	**100.00%**

General Service Less Than 50 kW

Consumption	2,000	kWh	0	kW	Loss Factor 1.0719

	May 2008 BILL			May 2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Energy First Tier (kWh)	750	$ 0.0530	$ 39.75	750	$ 0.0530	$ 39.75	$0.00	0.0%	16.00%
Energy Second Tier (kWh)	1,393	$ 0.0620	$ 86.37	1,394	$ 0.0620	$ 86.42	$0.05	0.1%	34.79%
Sub-Total: Energy			**$ 126.12**			**$ 126.17**	**$0.05**	**0.0%**	**50.80%**
Monthly Service Charge	1	$ 32.87	$ 32.87	1	$ 21.34	$ 21.34	($11.53)	(35.1)%	8.59%
Distribution (kWh)	2,000	$ 0.0154	$ 30.80	2,000	$ 0.0243	$ 48.60	$17.80	57.8%	19.57%
Distribution (kW)	0	$ -	$ -	0	$ -	$ -	$0.00	0.0%	0.00%
Regulatory Assets (kWh)	2,000	$ -	$ -	2,000	$ 0.0002	$ 0.40	$0.40	0.0%	0.16%
Rate Riders	2,000	$ -	$ -	2,000	$ -	$ -	$0.00	0.0%	0.00%
Monthly Rate Rider Adjustment Z-Factor	1	$ -	$ -	1	$ -	$ -	$0.00	0.0%	0.00%
Volumetric Rate Rider Adjustment Z-Factor	2,000	$ -	$ -	2,000	$ -	$ -	$0.00	0.0%	0.00%
Retail Transmission Rate – Network Service Rate	2,143	$ 0.0039	$ 8.36	2,144	$ 0.0039	$ 8.36	$0.00	0.0%	3.37%
Retail Transmission Rate – Line and Transformation Connection Service Rate	2,143	$ 0.0037	$ 7.93	2,144	$ 0.0037	$ 7.93	$0.00	0.0%	3.19%
Sub-Total: Delivery			**$ 79.96**			**$ 86.63**	**$6.68**	**8.3%**	**34.88%**
Wholesale Market Service Rate	2,143	$ 0.0052	$ 11.14	2,144	$ 0.0052	$ 11.15	$0.00	0.0%	4.49%
Rural Rate Protection Charge	2,143	$ 0.0010	$ 2.14	2,144	$ 0.0010	$ 2.14	$0.00	0.0%	0.86%
Regulated Price Plan – Administration Charge	1	$ 0.2500	$ 0.25	1	$ 0.2500	$ 0.25	$0.00	0.0%	0.10%
Sub-Total: Regulatory			**$ 13.54**			**$ 13.54**	**$0.00**	**0.0%**	**5.45%**
Debt Retirement Charge (DRC)	2,000	$ 0.0051	**$ 10.20**	2,000	$ 0.0051	**$ 10.20**	**$0.00**	**0.0%**	**4.11%**
Total Bill before Taxes			**$ 229.81**			**$ 236.54**	**$6.73**	**2.9%**	**95.24%**
GST	$ 229.81	5%	**$ 11.49**	$ 236.54	5%	**$ 11.83**	**$0.34**	**2.9%**	**4.76%**
Total Bill after Taxes			**$ 241.30**			**$ 248.37**	**$7.07**	**2.9%**	**100.00%**

General Service 50 to 4,999 kW

Consumption	**44,320**	**kWh**	**139**	**kW**	***Loss Factor 1.0719***

	May 2008 BILL			May 2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Energy First Tier (kWh)	750	$ 0.0530	$ 39.75	750	$ 0.0530	$ 39.75	$0.00	0.0%	0.72%
Energy Second Tier (kWh)	46,739	$ 0.0620	$ 2,897.81	46,757	$ 0.0620	$ 2,898.91	$1.10	0.0%	52.79%
Sub-Total: Energy			**$ 2,937.56**			**$ 2,938.66**	**$1.10**	**0.0%**	**53.52%**
Monthly Service Charge	1	$ 764.96	$ 764.96	1	$ 148.11	$ 148.11	($616.85)	(80.6)%	2.70%
Distribution (kWh)	44,320	$ -	$ -	44,320	$ -	$ -	$0.00	0.0%	0.00%
Distribution (kW)	139	$ 3.5235	$ 489.77	139	$ 8.1769	$ 1,136.59	$646.82	132.1%	20.70%
Regulatory Assets (kW)	139	$ -	$ -	139	$ 0.0656	$ 9.12	$9.12	0.0%	0.17%
Rate Riders	139	$ -	$ -	139	$ -	$ -	$0.00	0.0%	0.00%
Monthly Rate Rider Adjustment Z-Factor	1	$ -	$ -	1	$ -	$ -	$0.00	0.0%	0.00%
Volumetric Rate Rider Adjustment Z-Factor	139	$ -	$ -	139	$ -	$ -	$0.00	0.0%	0.00%
Retail Transmission Rate – Network Service Rate	149	$ 1.5794	$ 235.23	149	$ 1.6231	$ 241.83	$6.59	2.8%	4.40%
Retail Transmission Rate – Line and Transformation Connection Service Rate	149	$ 1.4741	$ 219.55	149	$ 1.5725	$ 234.29	$14.74	6.7%	4.27%
Sub-Total: Delivery			**$ 1,709.51**			**$ 1,769.94**	**$60.43**	**3.5%**	**32.23%**
Wholesale Market Service Rate	47,489	$ 0.0052	$ 246.94	47507	$ 0.0052	$ 247.03	$0.09	0.0%	4.50%
Rural Rate Protection Charge	47,489	$ 0.0010	$ 47.49	47507	$ 0.0010	$ 47.51	$0.02	0.0%	0.87%
Regulated Price Plan – Administration Charge	1	$ 0.2500	$ 0.25	1	$ 0.2500	$ 0.25	$0.00	0.0%	0.00%
Sub-Total: Regulatory			**$ 294.68**			**$ 294.79**	**$0.11**	**0.0%**	**5.37%**
Debt Retirement Charge (DRC)	44,320	$ 0.0051	**$ 226.03**	44,320	$ 0.0051	**$ 226.03**	**$0.00**	**0.0%**	**4.12%**
Total Bill before Taxes			**$ 5,167.78**			**$ 5,229.42**	**$61.64**	**1.2%**	**95.24%**
GST	$ 5,167.78	5%	**$ 258.39**	$ 5,229.42	5%	**$ 261.47**	**$3.08**	**1.2%**	**4.76%**
Total Bill after Taxes			**$ 5,426.17**			**$ 5,490.89**	**$64.72**	**1.2%**	**100.00%**

Unmetered Scattered Load

Consumption	**750**	**kWh**	**0**	**kW**	***Loss Factor 1.0719***

	May 2008 BILL			May 2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Energy First Tier (kWh)	750	$ 0.0530	$ 39.75	750	$ 0.0530	$ 39.75	$0.00	0.0%	33.72%
Energy Second Tier (kWh)	54	$ 0.0620	$ 3.32	54	$ 0.0620	$ 3.34	$0.02	0.6%	2.84%
Sub-Total: Energy			**$ 43.07**			**$ 43.09**	**$0.02**	**0.0%**	**36.55%**
Monthly Service Charge	1	$ 32.87	$ 32.87	1	$ 36.39	$ 36.39	$3.52	10.7%	30.87%
Distribution (kWh)	750	$ 0.0154	$ 11.55	750	$ 0.0232	$ 17.40	$5.85	50.6%	14.76%
Distribution (kW)	0	$ -	$ -	0	$ -	$ -	$0.00	0.0%	0.00%
Regulatory Assets (kWh)	750	$ -	$ -	750	$ 0.0003	$ 0.23	$0.23	0.0%	0.19%
Rate Riders	750	$ -	$ -	750	$ -	$ -	$0.00	0.0%	0.00%
Monthly Rate Rider Adjustment Z-Factor	1	$ -	$ -	1	$ -	$ -	$0.00	0.0%	0.00%
Volumetric Rate Rider Adjustment Z-Factor	750	$ -	$ -	750	$ -	$ -	$0.00	0.0%	0.00%
Retail Transmission Rate – Network Service Rate	804	$ 0.0039	$ 3.13	804	$ 0.0039	$ 3.14	$0.00	0.0%	2.66%
Retail Transmission Rate – Line and Transformation Connection Service Rate	804	$ 0.0037	$ 2.97	804	$ 0.0037	$ 2.97	$0.00	0.0%	2.52%
Sub-Total: Delivery			**$ 50.53**			**$ 60.12**	**$9.60**	**19.0%**	**51.00%**
Wholesale Market Service Rate	804	$ 0.0052	$ 4.18	804	$ 0.0052	$ 4.18	$0.00	0.0%	3.55%
Rural Rate Protection Charge	804	$ 0.0010	$ 0.80	804	$ 0.0010	$ 0.80	$0.00	0.0%	0.68%
Regulated Price Plan – Administration Charge	1	$ 0.2500	$ 0.25	1	$ 0.2500	$ 0.25	$0.00	0.0%	0.21%
Sub-Total: Regulatory			**$ 5.23**			**$ 5.23**	**$0.00**	**0.0%**	**4.44%**
Debt Retirement Charge (DRC)	750	$ 0.0051	**$ 3.83**	750	$ 0.0051	**$ 3.83**	**$0.00**	**0.0%**	**3.24%**
Total Bill before Taxes			**$ 102.66**			**$ 112.28**	**$9.62**	**9.4%**	**95.24%**
GST	$ 102.66	5%	**$ 5.13**	$ 112.28	5%	**$ 5.61**	**$0.48**	**9.4%**	**4.76%**
Total Bill after Taxes			**$ 107.79**			**$ 117.89**	**$10.10**	**9.4%**	**100.00%**

Sentinel Lighting

Consumption	3,000	kWh	10	kW	Loss Factor 1.0719

	May 2008 BILL			May 2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Energy First Tier (kWh)	750	$ 0.0530	$ 39.75	750	$ 0.0530	$ 39.75	$0.00	0.0%	11.40%
Energy Second Tier (kWh)	2,465	$ 0.0620	$ 152.80	2,466	$ 0.0620	$ 152.87	$0.07	0.0%	43.85%
Sub-Total: Energy			**$ 192.55**			**$ 192.62**	**$0.07**	**0.0%**	**55.25%**
Monthly Service Charge	15	$ 1.78	$ 26.70	15	$ 2.94	$ 44.10	$17.40	65.2%	12.65%
Distribution (kWh)	3,000	$ -	$ -	3,000	$ -	$ -	$0.00	0.0%	0.00%
Distribution (kW)	10	$ 2.6201	$ 26.20	10	$ 3.3822	$ 33.82	$7.62	29.1%	9.70%
Regulatory Assets (kWh)	10	$ -	$ -	10	$ 0.0727	$ 0.73	$0.73	0.0%	0.21%
Rate Riders	10	$ -	$ -	10	$ -	$ -	$0.00	0.0%	0.00%
Monthly Rate Rider Adjustment Z-Factor	1	$ -	$ -	1	$ -	$ -	$0.00	0.0%	0.00%
Volumetric Rate Rider Adjustment Z-Factor	10	$ -	$ -	10	$ -	$ -	$0.00	0.0%	0.00%
Retail Transmission Rate – Network Service Rate	11	$ 1.1972	$ 12.83	11	$ 1.1972	$ 12.83	$0.00	0.0%	3.68%
Retail Transmission Rate – Line and Transformation Connection Service Rate	11	$ 1.1635	$ 12.47	11	$ 1.1635	$ 12.47	$0.00	0.0%	3.58%
Sub-Total: Delivery			**$ 78.20**			**$ 103.95**	**$25.76**	**32.9%**	**29.81%**
Wholesale Market Service Rate	3,215	$ 0.0052	$ 16.72	3,216	$ 0.0052	$ 16.72	$0.01	0.0%	4.80%
Rural Rate Protection Charge	3,215	$ 0.0010	$ 3.21	3,216	$ 0.0010	$ 3.22	$0.00	0.0%	0.92%
Regulated Price Plan – Administration Charge	1	$ 0.2500	$ 0.25	1	$ 0.2500	$ 0.25	$0.00	0.0%	0.07%
Sub-Total: Regulatory			**$ 20.18**			**$ 20.19**	**$0.01**	**0.0%**	**5.79%**
Debt Retirement Charge (DRC)	3,000	$ 0.0051	**$ 15.30**	3,000	$ 0.0051	**$ 15.30**	**$0.00**	**0.0%**	**4.39%**
Total Bill before Taxes			**$ 306.22**			**$ 332.06**	**$25.84**	**8.4%**	**95.24%**
GST	$ 306.22	5%	**$ 15.31**	$ 332.06	5%	**$ 16.60**	**$1.29**	**8.4%**	**4.76%**
Total Bill after Taxes			**$ 321.54**			**$ 348.67**	**$27.13**	**8.4%**	**100.00%**

Street Lighting

Consumption	46,000	kWh	129	kW	Loss Factor 1.0719

	May 2008 BILL			May 2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Energy First Tier (kWh)	750	$ 0.0530	$ 39.75	750	$ 0.0530	$ 39.75	$0.00	0.0%	0.72%
Energy Second Tier (kWh)	48,539	$ 0.0620	$ 3,009.42	48,557	$ 0.0620	$ 3,010.56	$1.14	0.0%	54.18%
Sub-Total: Energy			**$ 3,049.17**			**$ 3,050.31**	**$1.14**	**0.0%**	**54.89%**
Monthly Service Charge	557	$ 1.77	$ 985.89	557	$ 1.69	$ 941.33	($44.56)	(4.5)%	16.94%
Distribution (kWh)	46,000	$ -	$ -	46,000	$ -	$ -	$0.00	0.0%	0.00%
Distribution (kW)	129	$ 2.4164	$ 311.72	129	$ 3.3232	$ 428.69	$116.98	37.5%	7.71%
Regulatory Assets (kWh)	129	$ -	$ -	129	$ 0.0687	$ 8.86	$8.86	0.0%	0.16%
Rate Riders	129	$ -	$ -	129	$ -	$ -	$0.00	0.0%	0.00%
Monthly Rate Rider Adjustment Z-Factor	1	$ -	$ -	1	$ -	$ -	$0.00	0.0%	0.00%
Volumetric Rate Rider Adjustment Z-Factor	129	$ -	$ -	129	$ -	$ -	$0.00	0.0%	0.00%
Retail Transmission Rate – Network Service Rate	138	$ 1.1911	$ 164.64	138	$ 1.1911	$ 164.70	$0.06	0.0%	2.96%
Retail Transmission Rate – Line and Transformation Connection Service Rate	138	$ 1.1396	$ 157.52	138	$ 1.1396	$ 157.58	$0.06	0.0%	2.84%
Sub-Total: Delivery			**$ 1,619.76**			**$ 1,701.16**	**$81.40**	**5.0%**	**30.62%**
Wholesale Market Service Rate	49289	$ 0.0052	$ 256.30	49307	$ 0.0052	$ 256.40	$0.10	0.0%	4.61%
Rural Rate Protection Charge	49289	$ 0.0010	$ 49.29	49307	$ 0.0010	$ 49.31	$0.02	0.0%	0.89%
Regulated Price Plan – Administration Charge	1	$ 0.2500	$ 0.25	1	$ 0.2500	$ 0.25	$0.00	0.0%	0.00%
Sub-Total: Regulatory			**$ 305.84**			**$ 305.96**	**$0.11**	**0.0%**	**5.51%**
Debt Retirement Charge (DRC)	46,000	$ 0.0051	**$ 234.60**	46,000	$ 0.0051	**$ 234.60**	**$0.00**	**0.0%**	**4.22%**
Total Bill before Taxes			**$ 5,209.37**			**$ 5,292.03**	**$82.65**	**1.6%**	**95.24%**
GST	$ 5,209.37	5%	**$ 260.47**	$ 5,292.03	5%	**$ 264.60**	**$4.13**	**1.6%**	**4.76%**
Total Bill after Taxes			**$ 5,469.84**			**$ 5,556.63**	**$86.79**	**1.6%**	**100.00%**

CNPI - Eastern Ontario Power
Bill Impacts May 2009 Compared To May 2008
Distribution Rates Calculated on the Basis of the Cost Allocation Informational Filing

Class	Consumption kWh	Consumption kW	May 2008 Bill	May 2009 Bill	Difference $	Bill Impact %	Max	Min
Residential	250		$ 39.67	$ 43.58	$ 3.91	9.9%	9.9%	9.1%
	500		$ 61.94	$ 68.03	$ 6.09	9.8%		
Average Customer	791		$ 90.20	$ 98.84	$ 8.64	9.6%		
	1,000		$ 110.93	$ 121.40	$ 10.47	9.4%		
	1,250		$ 135.73	$ 148.39	$ 12.66	9.3%		
	1,500		$ 160.53	$ 175.37	$ 14.84	9.2%		
	2,000		$ 210.13	$ 229.35	$ 19.22	9.1%		
General Service Less Than 50 kW	1,000		$ 134.49	$ 131.97	$ (2.52)	-1.9%	8.1%	-1.9%
	2,000		$ 241.30	$ 248.37	$ 7.07	2.9%		
Average Customer	2,807		$ 327.49	$ 342.30	$ 14.80	4.5%		
	4,000		$ 454.91	$ 481.15	$ 26.24	5.8%		
	6,000		$ 668.52	$ 713.94	$ 45.41	6.8%		
	10,000		$ 1,095.75	$ 1,179.51	$ 83.76	7.6%		
	15,000		$ 1,629.77	$ 1,761.47	$ 131.70	8.1%		
General Service 50 to 4,999 kW	25,000	50	$ 3,205.27	$ 2,814.10	$ (391.17)	-12.2%	7.7%	-12.2%
	40,000	75	$ 4,614.92	$ 4,352.08	$ (262.84)	-5.7%		
Average Customer	44,320	139	$ 5,426.17	$ 5,490.89	$ 64.72	1.2%		
	50,000	150	$ 5,970.90	$ 6,092.06	$ 121.16	2.0%		
	75,000	175	$ 8,201.41	$ 8,451.19	$ 249.78	3.0%		
	125,000	300	$ 13,197.55	$ 14,088.28	$ 890.73	6.7%		
	250,000	500	$ 24,885.21	$ 26,802.74	$ 1,917.53	7.7%		
Unmetered Scattered Load	250		$ 58.95	$ 64.78	$ 5.83	9.9%	9.9%	9.1%
	350		$ 68.61	$ 75.30	$ 6.68	9.7%		
	500		$ 83.12	$ 91.08	$ 7.96	9.6%		
	600		$ 92.78	$ 101.60	$ 8.82	9.5%		
	750		$ 107.79	$ 117.89	$ 10.10	9.4%		
Average Customer	985		$ 132.89	$ 145.00	$ 12.10	9.1%		
	1,000		$ 134.49	$ 146.73	$ 12.23	9.1%		
Sentinel Lighting	300	1	$ 29.13	$ 29.33	$ 0.20	0.7%	8.5%	0.7%
	900	3	$ 90.75	$ 98.28	$ 7.53	8.3%		
	1,500	5	$ 156.42	$ 169.38	$ 12.96	8.3%		
	3,000	10	$ 321.54	$ 348.67	$ 27.13	8.4%		
	4,500	15	$ 486.65	$ 527.96	$ 41.31	8.5%		
Street Lighting	3,000	10	$ 322.62	$ 331.53	$ 8.91	2.8%	2.8%	1.6%
	4,500	15	$ 486.41	$ 499.82	$ 13.41	2.8%		
	6,000	20	$ 650.20	$ 668.11	$ 17.90	2.8%		
	30,000	100	$ 3,287.62	$ 3,376.72	$ 89.10	2.7%		
557 Connections	46,000	129	$ 5,469.84	$ 5,556.63	$ 86.79	1.6%		

INTERROGATORY # 66 – Retail Transmission Rate

CNPI – EOP specific interrogatories

Ref:
Exhibit 9, Tab 1, Schedule 1, page 11
Guideline – Electricity Distribution Retail Transmission Service Rates (G-2008-0001)

- The 1st reference states that CNPI – EOP is not forecasting a change from the current Board Approved Retail Transmission Rates.
- The 2nd reference provide 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 CNPI – EOP is 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.

CNPI – EOP 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
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:

CNPI – Eastern Ontario Power has completed an analysis of the charges arising from the application of the Hydro One Networks Retail Transmission Service Charges and revenues received through distribution rates for the years 2006 and 2007.

CNPI – Eastern Ontario Power is an embedded distributor embedded in Hydro One Networks' 44 kV sub-transmission distribution system with a single point of supply. All

Retail Transmission Service Charges applicable to CNPI – Eastern Ontario Power are associated with that delivery point.

CNPI – Eastern Ontario Power reviewed the period from January 2006 to December 2007 to analyze the relationship between the Retail Transmission Service Charges from Hydro One Network's and the revenue associated with retail transmission revenues received through distribution rates for the years 2006 and 2007.

This analysis is shown in detail in Attachment A to this response entitled, "EOP RTSR Trend.xls". Based on this analysis, CNPI – EOP is forecasting a 15% decrease in the Retail Transmission Network Service Rate and a 15 % decrease in the Retail Transmission Line and Transformation Connection Service Rate. This proposed decrease in rates is likely due to the presence of embedded generation which displaces a portion of the load serviced by Hydro One Networks.

Hydro One Networks Inc. is currently billing CNPI – Eastern Ontario Power Interim Retail Transmission Service Charges that became effective May 1, 2008. These same charges, shown below, are contained in the current Hydro One Networks electricity distribution rate application now before the OEB.

The current Interim Retail Transmission Service Charges are:

Network Service Rate	\$2.01 per kW
Line Connection Service Rate	\$0.50 per kW
Transformation Connection Service Rate	\$1.38 per kW

CNPI – Eastern Ontario Power has not forecasted a change in the Hydro One Networks Inc.'s rates and will follow Board direction in this matter.

The following table is an excerpt from Attachment A and shows the proposed changes to the Retail Transmission Service Rates to be effective May 1, 2009. CNPI – Eastern

Ontario Power will file an update to the Application detailing the calculations for the adjustments to the Retail Transmission Service Rates.

2009 RTS Rate Change
CNPI - Eastern Ontario Power

Retail Transmission Rates		**Existing Rate**	**Effective January 1, 2009**	**Percent Change**
Network Service Rate	$/kW	2.01	2.01	0.00%
Line Connection Service Rate	$/kW	0.50	0.50	0.00%
Transformation Connection Service Rate	$/kW	1.38	1.38	0.00%
Retail Transmission Rate - Onging Variance Adjustment				
Retail Transmission Rates - Network Service Rate Adjustment				-15%
Retail Transmission Rates - Line and Transformation Connection Service Rate Adjustment				-15%
Retail Transmission Rates - Network Service Rate Adjustment			-15%	
Retail Transmission Rates - Line and Transformation Connection Service Rate Adjustment			-15%	

		2008 Tariff Sheet	**2009 Updated**
Residential			
Retail Transmission Rate – Network Service Rate	$/kWh	0.0043	0.0037
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0041	0.0035
General Service Less Than 50 kW			
Retail Transmission Rate – Network Service Rate	$/kWh	0.0039	0.0033
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0037	0.0031
General Service 50 to 4,999 kW			
Retail Transmission Rate – Network Service Rate	$/kW	1.5794	1.3425
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.4741	1.2530
General Service 50 to 4,999 kW - Time of Use			
Retail Transmission Rate – Network Service Rate	$/kW	1.6775	1.4259
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.6160	1.3736
Unmetered Scattered Load			
Retail Transmission Rate – Network Service Rate	$/kWh	0.0039	0.0033
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0037	0.0031
Sentinel Lighting			
Retail Transmission Rate – Network Service Rate	$/kW	1.1972	1.0176
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.1635	0.9890
Street Lighting			
Retail Transmission Rate – Network Service Rate	$/kW	1.1911	1.0124
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.1396	0.9687

ATTACHMENT A: OEB INTERROGATORY # 66

2009 RTS Rate Change
CNPI - Eastern Ontario Power

Retail Transmission Rates		Existing Rate	Effective January 1, 2009	Percent Change
Network Service Rate	$/kW	2.01	2.01	0.00%
Line Connection Service Rate	$/kW	0.50	0.50	0.00%
Transformation Connection Service Rate	$/kW	1.38	1.38	0.00%

Retail Transmission Rate - Onging Variance Adjustment	
Retail Transmission Rates - Network Service Rate Adjustment	-15%
Retail Transmission Rates - Line and Transformation Connection Service Rate Adjustment	-15%

Retail Transmission Rates - Network Service Rate Adjustment	-15%
Retail Transmission Rates - Line and Transformation Connection Service Rate Adjustment	-15%

		2008 Tariff Sheet	2009 Updated
Residential			
Retail Transmission Rate – Network Service Rate	$/kWh	0.0043	0.0037
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0041	0.0035
General Service Less Than 50 kW			
Retail Transmission Rate – Network Service Rate	$/kWh	0.0039	0.0033
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0037	0.0031
General Service 50 to 4,999 kW			
Retail Transmission Rate – Network Service Rate	$/kW	1.5794	1.3425
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.4741	1.2530
General Service 50 to 4,999 kW - Time of Use			
Retail Transmission Rate – Network Service Rate	$/kW	1.6775	1.4259
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.6160	1.3736
Unmetered Scattered Load			
Retail Transmission Rate – Network Service Rate	$/kWh	0.0039	0.0033
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0037	0.0031
Sentinel Lighting			
Retail Transmission Rate – Network Service Rate	$/kW	1.1972	1.0176
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.1635	0.9890
Street Lighting			
Retail Transmission Rate – Network Service Rate	$/kW	1.1911	1.0124
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.1396	0.9687

Summary of Retail Transmission Rates - Network and Connection

CNPI - Eastern Ontario Power

Single Sub-Transmission Delivery Point

	2006						2007					
	Network Service			Connection Service			Network Service			Connection Service		
	Charge	Revenue	Spread	Charge	Revenue	Spread	Charge	Revenue	Spread	Charge	Revenue	Spread
January	26,891	49,914	(23,023)	22,770	44,515	(21,745)	26,170	37,101	(10,931)	21,705	30,628	(8,923)
February	30,253	35,737	(5,484)	25,616	31,190	(5,574)	28,640	28,027	613	24,662	23,145	1,517
March	31,205	36,018	(4,813)	26,423	30,511	(4,088)	29,015	41,787	(12,772)	24,169	34,485	(10,316)
April	27,958	35,881	(7,923)	23,644	31,219	(7,575)	22,012	25,794	(3,782)	18,488	21,287	(2,799)
May	24,668	24,792	(124)	20,459	20,056	403	22,730	28,273	(5,543)	18,851	23,326	(4,475)
June	28,252	25,257	2,995	23,431	21,105	2,326	28,922	28,231	691	23,987	23,251	736
July	35,963	34,052	1,911	29,826	28,096	1,730	29,640	27,017	2,623	24,583	22,282	2,301
August	35,287	34,078	1,209	29,266	28,212	1,054	31,235	32,407	(1,172)	25,905	26,723	(818)
September	27,070	46,361	(19,291)	22,451	43,657	(21,206)	29,922	24,176	5,746	24,817	19,955	4,862
October	27,652	40,179	(12,527)	22,934	33,101	(10,167)	24,295	30,789	(6,494)	20,641	25,353	(4,712)
November	23,111	21,680	1,431	19,167	17,909	1,258	30,016	27,318	2,698	24,894	22,483	2,411
December	21,705	38,172	(16,467)	18,001	29,837	(11,836)	31,737	36,374	(4,637)	26,321	29,937	(3,616)
Totals	340,015	422,121	(82,106)	283,988	359,408	(75,420)	334,334	367,294	(32,960)	279,023	302,855	(23,832)
Averages	28,335	35,177	(6,842)	23,666	29,951	(6,285)	27,861	30,608	(2,747)	23,252	25,238	(1,986)

Summary of Retail Transmission Rates - Network and Connection
CNPI - Eastern Ontario Power
Normalized Data
Single Sub-Transmission Delivery Point

	Normalized					
	Network Service			Connection Service		
	Charge	Revenue	Spread	Charge	Revenue	Spread
January	26,531	43,508	(16,977)	22,238	37,572	(15,334)
February	29,447	31,882	(2,436)	25,139	27,168	(2,029)
March	30,110	38,903	(8,793)	25,296	32,498	(7,202)
April	24,985	30,838	(5,853)	21,066	26,253	(5,187)
May	23,699	26,533	(2,834)	19,655	21,691	(2,036)
June	28,587	26,744	1,843	23,709	22,178	1,531
July	32,802	30,535	2,267	27,205	25,189	2,016
August	33,261	33,243	19	27,586	27,468	118
September	28,496	35,269	(6,773)	23,634	31,806	(8,172)
October	25,974	35,484	(9,511)	21,788	29,227	(7,440)
November	26,564	24,499	2,065	22,031	20,196	1,835
December	26,721	37,273	(10,552)	22,161	29,887	(7,726)
Totals	337,175	394,708	(57,533)	281,506	331,132	(49,626)
Averages	28,098	32,892	(4,794)	23,459	27,594	(4,136)

Notes:
Normalization has been accomplished by combining and averaging both 2006 and 2007.

Require Adjustment to RTSR to Adjust for Variance

Network Service Rate	Connection Service Rate
-15%	-15%

INTERROGATORY # 67 - Cost Allocation & Rate Design

CNPI – Fort Erie specific interrogatories

Ref:
Exhibit 8, Tab 1, Schedule 2, Appendix A, Sheet O1
Exhibit 8, Tab 1, Schedule 2, Appendix A, Sheet O2
Exhibit 10, Tab 1, Schedule 3, page 6
Exhibit 10, Tab 1, Schedule 3, pages 14 to 22
Exhibit 10, Tab 1, Schedule 7, pages 2 to 4

- The 1st reference provides Sheet O1 from the Cost Allocation Informational Filing (Run 2).
- The 2nd reference provides Sheet O2 from the Cost Allocation Informational Filing (Run 2).
- The 3rd reference provides harmonized base revenue requirement.
- The 4th reference provides revenue-to-cost ratios based on harmonized rates across CNPI – Fort Erie and CNPI – EOP.
- The 5th reference provides bill impact calculations based on harmonized rates between CNPI – Fort Erie and CNPI – EOP.

a) Please confirm that the harmonized base revenue requirement of $11,476,276 provided in the 3rd reference represents the combined revenue requirement of CNPI – Fort Erie and CNPI – EOP. Further please confirm that of this amount, $9,252,464 is attributable to the former and $2,223,812 to the latter.
b) Please provide a breakdown by rate class of CNPI – Fort Erie's component of the harmonized base revenue requirement of $11,476,276 referred to above.
c) With respect to the USL rate class:
    - The application acknowledges in the 4th reference the need to gradually move the revenue-to-cost ratio towards 100%. However the ratio has changed from 56.76% in the Cost Allocation Informational Filing (1st reference) to 44.69% in the proposal for 2009 (4th reference). Please explain the reason for the apparent movement of the ratio to a value away from rather than towards 100%.
    - Please explain the reason for the 110% increase in the distribution component of the monthly bill from $25.06 for 2008 to $52.67 for 2009 (5th reference) when the revenue-to-cost ratio has declined as stated above.
    - As indicated in the 5th reference, the percentage increase in the monthly service charge from 2008 to 2009 ($8.56 to $36.39, i.e. 325%), contrasts against the percentage decrease in the volumetric rate ($0.0220/kWh to $0.0217/kWh, i.e. 1.4%). Moreover the proposed monthly service charge exceeds the Customer Unit Cost per month – Minimum System of $29.19 (2nd reference). Please provide a calculation of rates where the percentage increase in the monthly service charge is the same as the percentage increase in the volumetric rate and comment on how the

resulting monthly service charge compares with the Customer Unit Cost per month – Minimum System.

- In the 4th reference, the application states that effective May 1, 2009, CNPI – Fort Erie will implement billing on a per customer basis from a per connection basis. This will align with CNPI – EOP which currently bills on a per customer basis. Please explain the rationale for choosing per customer basis rather than per connection basis as the standard.

d) With respect to the Street Light rate class:
- The revenue-to-cost ratio has increased/improved from 19.16% in the Cost Allocation Informational Filing (1st reference) to 23.91% in the proposal for 2009 (4th reference). In order to analyze the impact of further improvement, please provide a calculation of rates that would yield a revenue- to-cost ratio of 40% together with a total bill impact calculation.
- Please explain the reason for the 43% increase in the distribution component of the monthly bill from $4,540.54 for 2008 to $6,475.67 for 2009 (5th reference) when the revenue-to-cost ratio has increased to a lesser extent as shown above.

e) With respect to the GS<50 rate class, as indicated in the 5th reference the percentage increase in the monthly service charge from 2008 to 2009 ($17.56 to $21.34, i.e. 22%) exceeds the percentage increase in the volumetric rate ($0.0222/kWh to $0.0228/kWh, i.e. 3%). Moreover the proposed monthly service charge exceeds the Customer Unit Cost per month – Minimum System of $28.30 (2nd reference). Please provide a calculation of rates where the percentage increase in the monthly service charge is the same as the percentage increase in the volumetric rate and comment on how the resulting monthly service charge compares with the Customer Unit Cost per month – Minimum System.

RESPONSE:

a) CNPI confirms that the harmonized base revenue requirement of $11,476,276 provided in the 3rd reference represents the combined revenue requirement of CNPI – Fort Erie and CNPI – EOP. Further CNPI confirms that $9,252,464 is attributable to the CNPI – Fort Erie and $2,223,812 to CNPI – Eastern Ontario Power.

b) The chart below calculates the breakdown by rate class of CNPI – EOP's and CNPI – Fort Erie's component of the harmonized base revenue requirement of $11,596,262.92 (the base revenue requirement of $11,476,276 plus transformer ownership credit of $119,986). The transformer ownership was included for consistency with the rate design models submitted.

As seen from the chart below, one of the effects of harmonizing electricity distribution rates is to shift some portion of the base revenue requirement. As discussed in Exhibit 10, Tab 1, Schedule 1 page 1 of the CNPI – Fort Erie Application, CNPI has determined that approximately $129,000 of the CNPI – EOP base revenue requirement (with transformer allowance) has shifted to CNPI – Fort Erie.

Harmonized Electricity Distribution Rates
Reconciliation of 2009 Revenue Requirement and 2009 Proposed Electricity Distribution Rates

		2009 Volumes		Proposed Rates		2009 Revenue		
Customer Class	No. of Customers / Connections	kWh	kW	Monthly Service Charge	Volumetric Charge	Total Class Distribution Revenue	2009 Base Revenue Requirement	Percentage by Class
Residential	17,369	144,908,264		17.69	0.0149	5,846,118	5,852,901	50.4%
General Service Less Than 50 kW	1,596	51,795,147		21.07	0.0228	1,584,336	1,581,936	13.7%
General Service 50 to 4,999 kW	180	166,344,327	457,378	147.84	8.0290	3,991,620	3,991,622	34.4%
Unmetered Scattered Load	28	444,370		36.39	0.0214	21,737	21,759	0.2%
Sentinel Lighting	1,051	877,992	2,664	2.94	3.3256	45,939	45,905	0.4%
Street Lighting	3,684	2,766,461	8,380	1.69	3.2908	102,289	102,139	0.9%
	23,907	367,136,561	468,422			11,592,038	11,596,262	100.0%

Fort Erie

				Proposed Rates				
Customer Class	No. of Customers / Connections	kWh	kW	Monthly Service Charge	Volumetric Charge	Total Class Distribution Revenue	2009 Base Revenue Requirement	Percentage by Class
Residential	14,255	114,834,621		17.69	0.0150	4,748,465	4,906,212	50.0%
General Service Less Than 50 kW	1,181	37,635,552		21.07	0.0228	1,156,568	1,228,727	12.2%
General Service 50 to 4,999 kW	146	146,222,353	395,124	147.84	8.0620	3,443,619	3,077,251	36.3%
Unmetered Scattered Load	20	345,359		36.39	0.0217	16,228	24,334	0.2%
Sentinel Lighting	961	797,374	2,423	2.94	3.3290	41,970	42,006	0.4%
Street Lighting	3,088	2,205,484	6,702	1.69	3.3000	84,730	85,030	0.9%
	19,747	302,040,745	404,249			9,491,579	9,363,560	100.0%

Gananoque

				Proposed Rates				
Customer Class	No. of Customers / Connections	kWh	kW	Monthly Service Charge	Volumetric Charge	Total Class Distribution Revenue	2009 Base Revenue Requirement	Percentage by Class
Residential	3,114	29,538,825		17.69	0.0150	1,104,122	1,095,227	52.5%
General Service Less Than 50 kW	415	13,980,635		21.07	0.0228	423,687	402,510	20.1%
General Service 50 to 4,999 kW	35	19,868,966	60,385	147.84	8.0620	548,028	702,719	26.1%
Unmetered Scattered Load	8	94,602		36.39	0.0217	5,546	4,937	0.3%
Sentinel Lighting	90	79,732	239	2.94	3.3290	3,969	4,136	0.2%
Street Lighting	597	553,300	1,655	1.69	3.3000	17,560	23,172	0.8%
	4,258	64,116,059	62,279			2,102,913	2,232,702	100.0%

c) Part I

The Cost Allocation Informational Filing for CNPI – Fort Erie indicated a 56.76% revenue to cost ratio for the USL class. The harmonized Cost Allocation Informational Filing indicated 57.76% revenue to cost ratio for the USL class. In CNPI harmonized rate design, Exhibit 10, the proposed cost to revenue ratio is 44.69%; the ratio was proposed in order to limit the combined USL class for Fort Erie and Gananoque to a 10% total bill impact in Gananoque. The pressure on rates comes from the change of billing USL customers from a per connection basis to a per customer basis.

Part II

The 110% increase in the distribution component of the monthly bill from $25.06 for 2008 to $52.67 for 2009 is caused by the change from a per connection billing format to a per customer billing format. The monthly service charge changes from $8.56 to $36.39, and the volumetric distribution rate reduces from $0.0220 to $0.0217.

Part III

Changing the fixed – variable split from the proposed 56.2% fixed and 43.8% variable to 22.75% fixed and 77.25% variable will yield a monthly service charge of $14.73 and a volumetric charge of $0.0378. Both charges are 72% increases over the 2008 approved rates.

The rate of $14.73 is below the upper bound from the Cost Allocation Informational Filing, $29.19.

The increased volumetric rate brought about by this notion will place more rate pressure on the high volume user. Under the proposal to bill on a per customer basis the rate shift to the volumetric component will have a greater impact.

Part IV

Of the three CNPI operating areas, only CNPI – Fort Erie currently bills the USL class on a per connection basis; CNPI – Eastern Ontario Power and CNPI – Port Colborne have historically billed on a per customer basis. CNPI believes it was more prudent to make CNPI – Fort Erie consistent with the other two operating areas than visa versa.

d) Part I

Increasing the revenue to cost ratio for the Street Lighting Class to 40% will yield a fixed monthly charge of $2.82 and a volumetric charge of $5.506; the resulting total bill impact is 33.2%.

Part II

Even though the revenue to cost ratio has only increased from 19.16% to 23.29%, the overall revenue requirement has increased from $7,959,520 to $9,252,454. The allocation of this new revenue requirement as well as the change in the revenue to cost ratio contribute to the increase in the distribution component of the bill.

e) Changing the fixed – variable split from the proposed 25.5% fixed and 74.5% variable to 22.35% fixed and 77.65% variable will yield a monthly service charge of $18.74 and a volumetric charge of $0.0237. Both charges are 6.7% increases over the 2008 approved rates. This change in fixed/variable split increases the total bill impact from -3.2% to 8.8% for a General Service less than 50 kW customer in Fort Erie. Previously the increases ranged from 3.1% to 3.2%. This change negatively impacts the larger user i.e., those above 2000 kWh per month.

The rate of $18.74 remains below the upper bound from the Cost Allocation Informational Filing.

INTERROGATORY # 68 – Retail Transmission Rate

CNPI – Fort Erie specific interrogatories

Ref:
Exhibit 9, Tab 1, Schedule 1, page 9
Guideline – Electricity Distribution Retail Transmission Service Rates (G-2008-0001)

- The 1st reference states that CNPI-Fort Erie is not forecasting a change from the current Board Approved Retail Transmission Rates.
- The 2nd reference provide 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.

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.

CNPI-Fort Erie 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
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:

CNPI – Fort Erie has completed an analysis of the charges arising from the application of the Uniform Transmission Rate ("UTR") and revenues received through distribution rates for the years 2006 and 2007.

CNPI – Fort Erie has two transmission delivery points; Transmission Station # 17 and Transmission Station # 18. Periodically, it is necessary to transfer load from one of these stations to the other to allow maintenance. Normally maintenance is scheduled for off peak periods, once per year, to minimize the impact of additional transmission charges from the IESO and ultimately their impact on the customers.

During the period of 2006 and 2007, there were three occasions for load transfers impacting the transmission charges from the IESO; October 2006, March 2007 and July 2007. CNPI – Fort Erie schedules maintenance in one month per year to minimize the impact on transmission charges. To properly assess the transmission costs, the July 2007 event has been normalized to the July 2006 amount. The October 2006 has been averaged with October 2007 and March 2007 has been averaged with March 2006. The effect is to factor in a single event for normalized forecasting of transmission charges from the IESO.

Based on this analysis, CNPI – Fort Erie is forecasting a 3% increase in the Retail Transmission Network Service Rate and a 5% increase in the Retail Transmission Line and Transformation Connection Service Rate. The details of this analysis are provided on Attachment A to this response entitled, “Fort Erie RTSR Trend.xls”.

In addition, the Retail Transmission Network Service Rate and the Retail Transmission Line and Transformation Connection Service Rate have been adjusted to reflect the proposed change in the Uniform Transmission Rate effective January 1, 2009.

The following table is an excerpt from Attachment A and shows the proposed changes to the Retail Transmission Service Rates to be effective May 1, 2009. CNPI – Fort Erie will file an update to the Application detailing the calculations for the adjustments to the Retail Transmission Service Rates.

2009 RTS Rate Change
CNPI - Fort Erie

Uniform Transmission Rate Adjustment		**Existing Rate**	**Effective January 1, 2009**	**Percent Change**
Network Service Rate	$/kW	2.31	2.57	11.26%
Line Connection Service Rate	$/kW	0.59	0.70	18.64%
Transformation Connection Service Rate	$/kW	1.61	1.62	0.62%

Retail Transmission Rate - Ongoing Variance Adjustment	
Retail Transmission Rates - Network Service Rate Adjustment	3%
Retail Transmission Rates - Line and Transformation Connection Service Rate Adjustment	5%

Retail Transmission Rates - Network Service Rate Adjustment	14.26%
Retail Transmission Rates - Line and Transformation Connection Service Rate Adjustment	10.45%

		2008 Tariff Sheet	**2009 Updated**
Residential			
Retail Transmission Rate – Network Service Rate	$/kWh	0.0044	0.0050
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045	0.0050
General Service Less Than 50 kW			
Retail Transmission Rate – Network Service Rate	$/kWh	0.0040	0.0046
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0040	0.0044
General Service 50 to 4,999 kW			
Retail Transmission Rate – Network Service Rate	$/kW	1.6442	1.8786
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.5973	1.7643
General Service 50 to 4,999 kW - Time of Use			
Retail Transmission Rate – Network Service Rate	$/kW		
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW		
Unmetered Scattered Load			
Retail Transmission Rate – Network Service Rate	$/kWh	0.0040	0.0046
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0040	0.0044
Sentinel Lighting			
Retail Transmission Rate – Network Service Rate	$/kW	1.3124	1.4995
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2607	1.3925
Street Lighting			
Retail Transmission Rate – Network Service Rate	$/kW	1.2400	1.4168
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2348	1.3639

ATTACHMENT A: OEB INTERROGATORY # 68

2009 RTS Rate Change
CNPI - Fort Erie

Uniform Transmission Rate Adjustment		Existing Rate	Effective January 1, 2009	Percent Change
Network Service Rate	$/kW	2.31	2.57	11.26%
Line Connection Service Rate	$/kW	0.59	0.70	18.64%
Transformation Connection Service Rate	$/kW	1.61	1.62	0.62%

Retail Transmission Rate - Ongoing Variance Adjustment	
Retail Transmission Rates - Network Service Rate Adjustment	3%
Retail Transmission Rates - Line and Transformation Connection Service Rate Adjustment	5%

Retail Transmission Rates - Network Service Rate Adjustment	14.26%
Retail Transmission Rates - Line and Transformation Connection Service Rate Adjustment	10.45%

		2008 Tariff Sheet	2009 Updated
Residential			
Retail Transmission Rate – Network Service Rate	$/kWh	0.0044	0.0050
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045	0.0050
General Service Less Than 50 kW			
Retail Transmission Rate – Network Service Rate	$/kWh	0.0040	0.0046
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0040	0.0044
General Service 50 to 4,999 kW			
Retail Transmission Rate – Network Service Rate	$/kW	1.6442	1.8786
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.5973	1.7643
General Service 50 to 4,999 kW - Time of Use			
Retail Transmission Rate – Network Service Rate	$/kW		
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW		
Unmetered Scattered Load			
Retail Transmission Rate – Network Service Rate	$/kWh	0.0040	0.0046
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0040	0.0044
Sentinel Lighting			
Retail Transmission Rate – Network Service Rate	$/kW	1.3124	1.4995
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2607	1.3925
Street Lighting			
Retail Transmission Rate – Network Service Rate	$/kW	1.2400	1.4168
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2348	1.3639

Summary of Retail Transmission Rates - Network and Connection

CNPI - Fort Erie

Transmission Delivery Points at Station 17 & Station 18

	2006						2007					
	Network Service			Connection Service			Network Service			Connection Service		
	Charge	Revenue	Spread	Charge	Revenue	Spread	Charge	Revenue	Spread	Charge	Revenue	Spread
January	126,693	155,102	(28,409)	104,293	135,346	(31,053)	134,332	172,923	(38,591)	112,109	147,264	(35,155)
February	124,064	122,318	1,746	105,133	106,298	(1,165)	142,329	165,162	(22,833)	117,680	140,387	(22,707)
March	121,506	142,255	(20,749)	100,579	123,499	(22,920)	172,893	55,943	116,950	154,753	49,743	105,010
April	110,200	132,444	(22,244)	93,835	115,163	(21,328)	111,411	107,532	3,879	98,317	91,762	6,555
May	135,209	107,639	27,570	116,923	91,489	25,434	123,963	129,338	(5,375)	105,718	110,187	(4,469)
June	131,884	122,119	9,765	114,487	103,808	10,679	154,708	128,440	26,268	129,591	109,114	20,477
July	154,062	137,770	16,292	133,335	117,690	15,645	201,182	134,103	67,079	188,124	114,642	73,482
August	163,897	163,435	462	139,123	139,813	(690)	159,326	155,212	4,114	133,170	132,565	605
September	114,949	128,963	(14,014)	99,704	110,321	(10,617)	152,619	112,131	40,488	128,774	95,960	32,814
October	180,107	118,776	61,331	160,941	101,251	59,690	117,688	146,166	(28,478)	98,837	124,566	(25,729)
November	126,626	130,381	(3,755)	127,516	110,949	16,567	102,462	117,340	(14,878)	100,551	99,978	573
December	146,840	140,775	6,065	130,820	120,343	10,477	110,166	135,889	(25,723)	109,749	116,462	(6,713)
Totals	1,636,037	1,601,977	34,060	1,426,689	1,375,970	50,719	1,683,079	1,560,179	122,900	1,477,373	1,332,630	144,743
Averages	136,336	133,498	2,838	118,891	114,664	4,227	140,257	130,015	10,242	123,114	111,053	12,062

Notes:

As evidence by the data shown above, there were three months over this two year period which required load to be transferred between Delivery Points. This is October 2006, March 2007 and July 2007. Planned maintenance is normally performed in off peak periods and usually limited to a single calendar month in order to minimize Uniform Transmission Charges and ultimately customer distribution rates.

To normalize the data, CNPI has elected to normalize the July 2007 charges from the IESO, this is shown on the next Tab.

Summary of Retail Transmission Rates - Network and Connection

CNPI - Fort Erie

Normalized Data

Transmission Delivery Points at Station 17 & Station 18

	Normalized					
	Network Service			Connection Service		
	Charge	Revenue	Spread	Charge	Revenue	Spread
January	130,513	164,013	(33,500)	108,201	141,305	(33,104)
February	133,197	143,740	(10,544)	111,407	123,343	(11,936)
March	147,200	99,099	48,101	127,666	86,621	41,045
April	110,806	119,988	(9,183)	96,076	103,463	(7,387)
May	129,586	118,489	11,098	111,321	100,838	10,483
June	143,296	125,280	18,017	122,039	106,461	15,578
July	154,062	135,937	18,126	133,335	116,166	17,169
August	161,612	159,324	2,288	136,147	136,189	(43)
September	133,784	120,547	13,237	114,239	103,141	11,099
October	148,898	132,471	16,427	129,889	112,909	16,981
November	114,544	123,861	(9,317)	114,034	105,464	8,570
December	128,503	138,332	(9,829)	120,285	118,403	1,882
Totals	1,635,998	1,581,078	54,920	1,424,637	1,354,300	70,337
Averages	136,333	131,757	4,577	118,720	112,858	5,861

Notes:

Normalization has been accomplished by combining and averaging both 2006 and 2007 in order to pick up the normal, off peak maintenance. July 2007 IESO charges have been normalized on the 2006 quantity.

Require Adjustment to RTSR to Adjust for Variance

Network Service Rate	Connection Service Rate
3%	5%

INTERROGATORY # 69 – Cost Allocation & Rate Design

CNPI – Port Colborne specific interrogatories

Ref:
Exhibit 9, Tab 1, Schedule 1, page 25
Exhibit 8, Tab 1, Schedule 2, Appendix A, Sheet O1
Exhibit 9, Tab 1, Schedule 1, page 6
Exhibit 9, Tab 1, Schedule 5, pages 2-4
Exhibit 8, Tab 1, Schedule 2, Appendix A, Sheet O2
Exhibit 9, Tab 1, Schedule 1, page 19

- The 1st reference provides revenue-to-cost ratio's for each rate class with respect to proposed rates for 2008 and in the Cost Allocation Informational Filing. Additionally the reference provides class revenue requirement expressed as a percentage of total revenue requirement, in the proposed allocation for 2009.
- The 2nd reference comprises Sheet O1 of the Cost Allocation Informational Filing (Run 2).
- The 3rd reference provides a calculation of base revenue requirement.
- The 4th reference comprises 2008-to2009 bill impact calculations for each rate class.
- The 5th reference comprises Sheet O2 of the Cost Allocation Informational Filing (Run 2).
- The 6th reference provides an analysis of proposed 2009 rates for the Unmetered Scattered Load (USL) rate class.

a) With respect to the GS>50 rate class:
   - Please explain the sharp increase in the class revenue requirement expressed as a percentage of total revenue requirement, in the proposed allocation for 2009 (29.6%[1]) compared to the allocation in the Cost Allocation Informational Filing (17.7%[2]), given that the revenue to cost ratio has dropped to135.6% in the former from167.1% in the latter (1st reference).
   - Please explain the method by which the transformer allowance of $141,484 (3rd reference) is allocated amongst the rate classes, including the rationale for doing this allocation.
   - Please explain the reason for the Monthly Service Charge proposed for 2009 ($649.87) as shown in the 4th reference being significantly higher than the Customer Unit Cost per month – Minimum System ($197.15), as shown in the 5th reference.

b) With respect to the USL rate class, the application acknowledges in the 6th reference the need to gradually move the revenue-to-cost ratio towards 100%. However the ratio has changed from 61.4% in the Cost Allocation Informational

[1] $1,684,608 divided by sum of proposed allocation column $5,683,947 per 1st reference.
[2] $866,865 divided by $4,908,033 per the 2nd reference.

Filing to 52.5% in the proposal for 2009 (1st reference). Please explain the reason for the apparent movement of the ratio to a value away from rather than towards 100%.

c) With respect to the Street light rate class, the revenue-to-cost ratio has increased/improved from 29.4% in the Cost Allocation Informational Filing to 38.7% in the proposal for 2009 (1st reference). In order to analyze the impact of further improvement, please provide a calculation of rates that would yield a revenue- to-cost ratio of 50% together with a total bill impact calculation.
d) With respect to the Sentinel rate class, as shown in the 4th reference, the percentage increase in the monthly service charge from 2008 to 2009 ($2.10 to $4.15, i.e. 98%) exceeds the percentage increase in the volumetric rate ($6.1316/kW to $6.6369/kW, i.e. 8%). Please provide a calculation of rates where the percentage increase in the monthly service charge is the same as the percentage increase in the volumetric rate and comment on how the resulting monthly service charge compares with the Customer Unit Cost per month – Minimum System.
e) Please confirm that the proposed distribution rates are reflected in the bill impact calculations provided in the 4th reference and further please explain the purpose of the bill impact calculations titled "Consistent with the 2006 EDR Methodology" provided in the Rate Design Model section of the application.
f) Please file an electronic copy of Run 2 of the Cost Allocation Informational Filing to be a part of the record of this application.

RESPONSE:

a) Part I

CNPI – Port Colborne believes that the more valid comparison is with the 2006 EDR and the Cost Allocation Informational Filing. The allocation to the GS > 50 kW class was $1,384,594 based on a revenue requirement of $4,455,806 or 31%. Based on the 2009 proposed revenue requirement, CNPI – Port Colborne has allocated 29.6% (a reduction of 1.4%) to the GS > 50 kW class; $1,684,608 of the total revenue requirement of $5,683,947. This reduced percentage allocation of the proposed revenue requirement has lowered the projected revenue-to-cost ratio.

Part II

CNPI provides, as part of its cost of service, voltage at utilization voltage; voltage already transformed to a standard secondary voltage usable by the customers. The cost of this transformation is included in the base revenue requirement and all customers pay for the service through their distribution rates including those who own their own transformation facilities. In CNPI's case, only the General Service 50 to 4,999 kW class includes customers that own their own transformation facilities.

The cost associated with providing transformation to all customers in a class is accomplished through cost allocation. To compensate the customers owning their own transformation facilities, a transformer ownership allowance is credited to those customers. This credit is a proxy for providing transformation service to the entire class. To maintain fairness, the cost is restricted to the class providing that service.

Part III

The monthly service charge in CNPI – Port Colborne, proposed at $649.87, is significantly higher than the Customer Unit Cost per month – Minimum System of $197.15. The monthly service charge in CNPI – Port Colborne has been historically at this higher level since distribution rates were first unbundled. The rationale for the ratio between the fixed and volumetric components of the distribution rate design that developed this rate, as CNPI – Port Colborne understands it, was to minimize the rate impacts to the then existing customers of the General Service 50 to 4,999 kW class. Following the Board's guidelines, CNPI – Port Colborne has not attempted to modify the existing underlying rationale in this rate design.

b) In the Cost Allocation Informational Filing, the base revenue requirement was $4,455,806. In the Application, the base revenue requirement has been determined to be $5,683,947. In the Cost Allocation Informational Filing the service revenue requirement for the USL class was determined to be $32,645. In the Application the service revenue requirement has been determined to be $39,847, an increase of 22%.

Over the same time frame, the USL customer class has not experienced growth. This increase in revenue requirement coupled with no growth in the class has forced CNPI – Port Colborne to reduce the allocation of revenue to the class in order to respect a total bill impact of 10%. The reduced allocation of revenue to the class ultimately reduced the classes' revenue-to-cost ratio.

c) In order to yield a 50% revenue-to-cost ratio, the revenue allocation to the class has been changed from 1.611% to 1.247%. With this allocation of revenue, the monthly service charge would move from $1.80 to $2.33 and the volumetric charge would move from $5.146 to $6.6573. The resulting total bill impacts would now range from 17.3% to 20%.

d) In order to bring the percentage change in the monthly service charge in line with the percentage change in the volumetric charge, the ratio of the fixed component to the volumetric component will change from 87.7%/12.3% to 80.1%/19.9%. This change will yield a monthly service charge of $3.79, and a volumetric rate of $11.0296, and result in a total bill impact ranging from 20.3% to 21.3%.

e) CNPI – Port Colborne confirms that the rates reflected in the total bill impact calculations provided in the 4th reference are the proposed distribution rates.

The calculations titled "Consistent with the 2006 EDR Methodology" provided in the Rate Design Model section of the Application are electricity distribution rates that would have been calculated consistent with the allocation of distribution revenue to the classes found in the Board Approved 2006 EDR. These were developed as a comparison to the proposed rates which have the allocations to the classes modified to achieve certain revenue-to-cost ratios.

f) CNPI – Port Colborne is submitting an electronic copy of the Run 2 of the Cost Allocation Informational Filing with these responses.

A copy can be found in the OEB Webdrawer and associated with the Application.

INTERROGATORY # 70 – Retail Transmission Rate

CNPI – Port Colborne specific interrogatories

Ref:
Exhibit 9, Tab 1, Schedule 1, page 11
Guideline – Electricity Distribution Retail Transmission Service Rates (G-2008-0001)

- The 1st reference states that CNPI-Port Colborne is not forecasting a change from the current Board Approved Retail Transmission Rates.
- The 2nd reference provide 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.

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.

CNPI-Port Colborne 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
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:

CNPI – Port Colborne has completed an analysis of the charges arising from the application of the Uniform Transmission Rate (“UTR”) and revenues received through distribution rates for the years 2006 and 2007.

CNPI – Port Colborne has a single point of supply from the IESO – controlled grid, Port Colborne TS which attracts Uniform Transmission rates. A very small portion of load is embedded in Hydro One Networks Inc.’s distribution system as an embedded Wholesale

Market Participant and attracts Hydro One Networks Retail Transmission Service Rates; however, this is negligible at less than one percent of annual costs and is not budgeted separately.

CNPI – Port Colborne reviewed the period from January 2006 to December 2007 to analyze the relationship between the Retail Transmission Service Charges and the revenue associated with retail transmission revenues received through distribution rates for the years 2006 and 2007.

This analysis is shown in detail in Attachment A to this response entitled, "Port Colborne RTSR Trend.xls". Based on this analysis, CNPI – Port Colborne is forecasting a 4% decrease in the Retail Transmission Network Service Rate and no change in the Retail Transmission Line and Transformation Connection Service Rate.

In addition, the Retail Transmission Network Service Rate and the Retail Transmission Line and Transformation Connection Service Rate have been adjusted to reflect the approved change in the Uniform Transmission Rate effective January 1, 2009.

The following table is an excerpt from Attachment A to this response and shows the proposed changes to the Retail Transmission Service Rates to be effective May 1, 2009.

CNPI – Port Colborne will file an update to the Application detailing the calculations for the adjustments to the Retail Transmission Service Rates.

2009 RTS Rate Change
CNPI - Port Colborne

Uniform Transmission Rates		Existing Rate	Effective January 1, 2009	Percent Change
Network Service Rate	$/kW	2.31	2.57	11.26%
Line Connection Service Rate	$/kW	0.59	0.70	18.64%
Transformation Connection Service Rate	$/kW	1.61	1.62	0.62%

Retail Transmission Rate - Ongoing Variance Adjustment	
Retail Transmission Rates - Network Service Rate Adjustment	-4%
Retail Transmission Rates - Line and Transformation Connection Service Rate Adjustment	0%

Retail Transmission Rates - Network Service Rate Adjustment	7.26%
Retail Transmission Rates - Line and Transformation Connection Service Rate Adjustment	5.45%

		2008 Tariff Sheet	2009 Updated
Residential			
Retail Transmission Rate – Network Service Rate	$/kWh	0.0042	0.0045
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0038	0.0040
General Service Less Than 50 kW			
Retail Transmission Rate – Network Service Rate	$/kWh	0.0035	0.0038
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0034	0.0036
General Service 50 to 4,999 kW			
Retail Transmission Rate – Network Service Rate	$/kW	1.4174	1.5202
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3549	1.4288
General Service 50 to 4,999 kW - Time of Use			
Retail Transmission Rate – Network Service Rate	$/kW		
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW		
Unmetered Scattered Load			
Retail Transmission Rate – Network Service Rate	$/kWh	0.0035	0.0038
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0034	0.0036
Sentinel Lighting			
Retail Transmission Rate – Network Service Rate	$/kW	1.0743	1.1522
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.0678	1.1260
Street Lighting			
Retail Transmission Rate – Network Service Rate	$/kW	1.0352	1.1103
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.0693	1.1276

ATTACHMENT A: OEB INTERROGATORY # 70

2009 RTS Rate Change
CNPI - Port Colborne

Uniform Transmission Rates		Existing Rate	Effective January 1, 2009	Percent Change
Network Service Rate	$/kW	2.31	2.57	11.26%
Line Connection Service Rate	$/kW	0.59	0.70	18.64%
Transformation Connection Service Rate	$/kW	1.61	1.62	0.62%

Retail Transmission Rate - Ongoing Variance Adjustment	
Retail Transmission Rates - Network Service Rate Adjustment	-4%
Retail Transmission Rates - Line and Transformation Connection Service Rate Adjustment	0%

Retail Transmission Rates - Network Service Rate Adjustment	7.26%
Retail Transmission Rates - Line and Transformation Connection Service Rate Adjustment	5.45%

		2008 Tariff Sheet	2009 Updated
Residential			
Retail Transmission Rate – Network Service Rate	$/kWh	0.0042	0.0045
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0038	0.0040
General Service Less Than 50 kW			
Retail Transmission Rate – Network Service Rate	$/kWh	0.0035	0.0038
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0034	0.0036
General Service 50 to 4,999 kW			
Retail Transmission Rate – Network Service Rate	$/kW	1.4174	1.5202
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3549	1.4288
General Service 50 to 4,999 kW - Time of Use			
Retail Transmission Rate – Network Service Rate	$/kW		
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW		
Unmetered Scattered Load			
Retail Transmission Rate – Network Service Rate	$/kWh	0.0035	0.0038
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0034	0.0036
Sentinel Lighting			
Retail Transmission Rate – Network Service Rate	$/kW	1.0743	1.1522
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.0678	1.1260
Street Lighting			
Retail Transmission Rate – Network Service Rate	$/kW	1.0352	1.1103
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.0693	1.1276

Summary of Retail Transmission Rates - Network and Connection

CNPI - Port Colborne

Transmission Delivery Point at Port Colborne TS & Embedded WMP at Crowland TS

	2006						2007					
	Network Service			Connection Service			Network Service			Connection Service		
	Charge	Revenue	Spread	Charge	Revenue	Spread	Charge	Revenue	Spread	Charge	Revenue	Spread
January	81,218	120,725	(39,507)	74,414	116,333	(41,919)	91,723	91,964	(241)	88,462	79,951	8,511
February	85,039	102,105	(17,066)	74,215	88,605	(14,390)	98,758	83,225	15,533	83,072	73,271	9,801
March	82,933	78,767	4,166	70,839	68,647	2,192	89,793	88,359	1,434	80,098	75,898	4,200
April	73,130	113,282	(40,152)	68,797	109,316	(40,519)	75,417	70,744	4,673	77,230	62,881	14,349
May	85,027	57,759	27,268	73,274	53,300	19,974	79,648	91,813	(12,165)	66,879	75,408	(8,529)
June	90,902	114,871	(23,969)	75,347	95,463	(20,116)	102,052	124,199	(22,147)	83,951	106,742	(22,791)
July	104,379	60,607	43,772	90,847	58,701	32,146	99,276	119,342	(20,066)	87,942	101,977	(14,035)
August	116,421	110,500	5,921	96,317	95,254	1,063	103,875	34,406	69,469	94,294	27,518	66,776
September	82,800	106,067	(23,267)	79,664	91,866	(12,202)	106,394	65,693	40,701	89,401	53,049	36,352
October	82,845	90,237	(7,392)	79,901	73,897	6,004	81,235	130,717	(49,482)	67,591	106,298	(38,707)
November	80,157	80,019	138	69,393	65,507	3,886	55,849	65,612	(9,763)	60,500	44,065	16,435
December	84,164	94,800	(10,636)	74,324	77,573	(3,249)	64,685	99,523	(34,838)	72,475	75,736	(3,261)
Totals	1,049,015	1,129,739	(80,724)	927,332	994,462	(67,130)	1,048,705	1,065,597	(16,892)	951,895	882,794	69,101
Averages	87,418	94,145	(6,727)	77,278	82,872	(5,594)	87,392	88,800	(1,408)	79,325	73,566	5,758

Summary of Retail Transmission Rates - Network and Connection
CNPI - Port Colborne
Normalized Data
Transmission Delivery Point at Port Colborne TS & Embedded WMP at Crowland TS

	Normalized					
	Network Service			Connection Service		
	Charge	Revenue	Spread	Charge	Revenue	Spread
January	86,471	106,345	(19,874)	81,438	98,142	(16,704)
February	91,899	92,665	(767)	78,644	80,938	(2,295)
March	86,363	83,563	2,800	75,469	72,273	3,196
April	74,274	92,013	(17,740)	73,014	86,099	(13,085)
May	82,338	74,786	7,552	70,077	64,354	5,723
June	96,477	119,535	(23,058)	79,649	101,103	(21,454)
July	104,379	89,975	14,405	90,847	80,339	10,508
August	110,148	72,453	37,695	95,306	61,386	33,920
September	94,597	85,880	8,717	84,533	72,458	12,075
October	82,040	110,477	(28,437)	73,746	90,098	(16,352)
November	68,003	72,816	(4,813)	64,947	54,786	10,161
December	74,425	97,162	(22,737)	73,400	76,655	(3,255)
Totals	1,051,412	1,097,668	(46,257)	941,066	938,628	2,438
Averages	87,618	91,472	(3,855)	78,422	78,219	203

Require Adjustment to RTSR to Adjust for Variance

Network Service Rate	Connection Service Rate
-4%	0%

INTERROGATORY #1

Ref: Exhibit 3/Tab 1/Schedule 2, page 1

a) Please confirm whether the rates used to determine the 2009 revenues by customer class:
   - Excluded the smart meter rate adder
   - Included/excluded the LV cost adder
   - Were reduced to reflect the transformer ownership allowance, where appropriate.

b) Please reconcile the Distribution revenues reported here for 2009 with the Base Revenue Requirement reported at Exhibit 9/Tab 1/Schedule 1, page 7.

c) Please reconcile the Distribution Revenues reported here for 2009 (by customer class) with those reported in the Rate Design Model (Reconciliation of 2009 Rates tab).

RESPONSE:

a) CNPI – Gananoque confirms that the rates used to determine the 2009 revenues by customer class excluded the smart meter adder, the LV cost adder and the transformer ownership allowance where appropriate.

b) During an attempt to reconcile the distribution revenues reported here for 2009 with the Base Revenue Requirement reported at Exhibit 9/Tab 1/Schedule 1, page 6, an error was found in the Rate Design Model. The genesis of the error is on Tab “DxRates 2006 EDR Distributions” in cells C10 to D15. The volumes in kWh and kW have been calculated as the average of the 2008 Bridge Year and the 2009 Test Year volumes. This is incorrect.

   These cells should contain the 2009 forecasted volumes. Effectively this error has understated the volumes and subsequently overstated the rates.

   This will be corrected in a subsequent rate design model and will factor any other issues arising in the interrogatory phase of the review, for example the recalculation of retail transmission rates.

c) Same as b) above.

INTERROGATORY # 2

Ref: Exhibit 3/Tab 2/Schedule 1, pages 2-5

a) Please provide a schedule that sets out:
   - the kWh per customer for the Residential, GS<50 and GS>50 customer classes based on the Hydro One Weather Normalized data (per page 3, lines 28-29).
   - The kWh per customer class for the Residential, GS<50 and GS>50 customer classes (for the same year) using CNP-EO's weather normalization methodology.

b) The CNP-EO weather normalization methodology is based on the premise that that the mix of weather sensitive and non-weather sensitive loads for CNP-EO is a reasonable subset of the overall IESO controlled grid. For weather sensitive load, the IESO normalization methodology captures the weather impacts across the entire province and, in doing so, reflects not only the weather across the entire province and reflects the amount of weather sensitive load (e.g., space heating and space cooling) in each customer class.
   - Why is it reasonable to assume that, for weather sensitive loads, the weather adjustment for CNP-EO would be the same as for the province as a whole? Are the heating and cooling degree days in CNP-EO similar to those for the province as a whole? Is the saturation of space heating and cooling appliances the same in CNP-EO as it is for the province as whole?

c) The table on page 5 only compares 30 years of weather data for CNP-EO with that for the years 2005, 2006 and 2007. Please explain how this comparison supports applying the weather correction factor derived from the IESO provincial data to the CNP-EO data.

d) With respect to the table of page 4, the impact of a heating degree day on electricity load will be different than the impact of a cooling degree day (i.e., each will depend respectively on the extent of installation of electric space heating and cooling equipment).
   - Please explain why it is reasonable to compare the sum of the mean heating and cooling days.

RESPONSE:

a) The table shown below highlights the 2004 data from the Cost Allocation Informational Filing, the Hydro One Weather Normalized data from the same filing and the 2004 data normalized using CNPI methodology used in this Application.

Comparison of Weather Normalization Data			
Class	Actual Data (kWh)	Hydro One Normalized Data (kWh)	CNPI Methodology (kWh)
Residential	28,793,211	34,496,299	29,647,586
GS < 50 kW	14,283,926	13,161,105	14,120,023
GS > 50 kW	42,507,317	39,316,197	42,070,186

The IESO correction factor as calculated consistent with the methodology used by CNPI was a 0.20% adjustment upward.

The Hydro One normalized data shows a great deal of volatility between actual sale data and the normalized data. CNPI has not seen this level of volatility in its sales year over year other than events associated with discrete activities such as customer closures.

b) Notwithstanding the discussion of the points raised in the question, CNPI suggests that the IESO weather correction formulation is a reasonable proxy to use in the Application.

For all electricity distribution companies' throughput and demand will be changing constantly in response to a number of external factors including customer additions and deletions, weather conditions, customer behaviour and industrial commercial activity. In smaller utilities, like CNPI, where there is limited diversity in its customer base, response to these factors maybe often skewed in response to singular events. For example the behavior of the embedded generators in CNPI – Port Colborne to gas price signals, industrial closures in Port Colborne and Gananoque and residential customer behavior in response to these externalities. Weather normalization is only one of many variables that have to be considered.

CNPI suggests that the IESO 18 Month Outlook: Ontario Demand Forecast is a reasonable proxy of the electrical system response to a wide range of variables in the economy and is the better choice for normalizing the throughput data of a smaller LDC like CNPI.

c) CNPI – Eastern Ontario Power has included this information only to illustrate the correlation between the total mean degree days and the normalizing adjustment factors used to develop the normalized throughput. Comparing the values for 2005 and 2006 shows a reduction in the number of mean degree days. Likewise the adjustment factor developed in this Application has reduced the throughput.

d) As discussed in part c), this was developed to show that a correlation existed in the trend of total mean degree days and the adjustments being made to throughput. As well, this information supports the notion that none of these years were extreme weather years.

CNPI confirms that the data presented in this table shows that for the period 2005-2007, the heating degree days were all lower than the 30 year average while the cooling degree days were all higher.

INTERROGATORY # 3

Ref: Exhibit 3/Tab 2/Schedule 1, pages 8-10

a) Please provide the Residential and GS<50 customer counts for each year from 2002 to 2007.

b) The Application makes reference to 'normalized average use per customer" for the Residential (page 8, line 10); GS<50 (page 9, line 18) and GS>50 (page 11, lines 1-2). Please describe how the weather normalized usage values were derived.

RESPONSE:

a) This information is provided in the Application, Exhibit 9, Tab 1, Schedule1, Appendix A Rate Design Model.

The restated customer counts are as follows:

Class	2002	2003	2004	2005	2006	2007
Residential	3,042	3,042	3,072	3,097	3,099	3,100
GS < 50 kW	378	378	398	405	412	409

CNPI – Gananoque did not come into existence as a distributor in the electricity market until April 2003. Accordingly, the 2002 values are a re-statement of 2003.

b) The matter of "normalized average use per customer" is discussed fully in the response to VECC-EOP Interrogatory # 2.

INTERROGATORY # 4

Ref: Exhibit 8/tab 1/Schedule 1, pages 2-3

a) Please confirm that the OEB's Cost Allocation Review Report directed that Miscellaneous Revenues be allocated based on weighted number of bills. If this is not the case, what is CNP-EO's understanding of the approach to be used?
b) What allocator was used to produce the results for Miscellaneous Revenues shown on page 2? Please explain why some values are negative while others are positive.
c) Please complete the following table (with the GS<50 TOU customers reclassified as GS>50 customers):
   - kWh by Customer Class (delivered)
   - Customer/Connection Count
d) Based on the results from part (c), please comment on the appropriateness of assuming that the revenue requirement proportions from the Updated 2006 Cost Allocation study can be used for setting 2009 rates.

RESPONSE:

a) Yes, it was CNPI – Eastern Ontario Power's understanding that the OEB directed that Miscellaneous Revenues be allocated based on weighted number of bills (CWNB).

b) The allocation found on Tab O1 Revenue to Cost | RR on line 19 was used to allocate the Miscellaneous Revenue and CNPI – Eastern Ontario Power's understanding is that it should be allocated on weighted number of bills (CWNB). CNPI – Eastern Ontario Power cannot explain why some values are negative while others are positive.

c)

Customer Class (all)	Cost Allocation Filing		2009 Application	
	kWh	% of Total	kWh	% of Total
Residential	28,793,211	33.6%	29,586,254	47.0%
GS < 50	14,283,926	16.6%	14,048,011	22.3%
GS > 50	42,507,317	49.5%	18,614,527	29.6%
Street Light	132,685	0.2%	555,619	0.9%
Sentinel	17,803	0.0%	80,618	0.1%
USL	80,136	0.1%	94,602	0.2%
Total	85,815,078	100.0%	62,979,631	100.0%

Customer Class (all)	Cost Allocation Filing		2009 Application	
	Number	% of Total	Number	% of Total
Residential	3,072	74.4%	3,119	73.1%
GS < 50	389	9.4%	417	9.8%
GS > 50	34	0.8%	35	0.8%
Street Light	566	13.7%	599	14.0%
Sentinel	58	1.4%	91	2.1%
USL	9	0.2%	8	0.2%
Total	4,128	100.0%	4,269	100.0%

d) It is CNPI – EOP's position that the proportions have not change significantly and the 2006 Cost Allocation study can be used for setting 2009 rates.

INTERROGATORY #5

Ref: Exhibit 8/Tab 1/Schedule 2, pages 1-3

a) Please describe for which customer classes' bill impact considerations (page 2, lines 6-11) precluded moving the revenue to cost ratios to within the ranges set by the Board and what the proposed bill impacts are for these customers.

RESPONSE:

In essence, all customer classes' bill impact considerations were taken into account when proposing the revenue to cost allocations. The positioning compared with the range set by the Board becomes a matter of fairness amongst the customer classes in addition to limiting the total bill impact for any given customer class.

In particular, CNPI – Eastern Ontario Power limited the proposed revenue to cost ratio for the classes due to bill impact considerations which are as follows: Residential (9.5%), General Service less than 50 kW (3.1%) and Street Lighting (10%).

In the case of the General Service less than 50 kW class, the primary consideration was the total bill impact on the other classes. This limited the ability to move the revenue to cost ratio into the range suggested by the Board's guidelines. Reducing the revenue to cost ratio for this class any further than the proposed 127.99% would transfer distribution revenues requirement to other customer classes. This action would force those classes to exceed the 10% total bill impact threshold or in the case of the General Service 50 to 4,999 kW, increase its current revenue to cost ratio, which is proposed at 145.03%.

INTERROGATORY # 6

Ref: i) Exhibit 8/Tab 1/Schedule 2, page 3
ii) Exhibit 9/Tab 1/Schedule 1, page 9, lines 22-30
iii) CNP-FE's Rate Design Model – Cost Allocation Review Tab

a) Please confirm that for purposes of the Cost Allocation Informational Filing:
   - The Revenues are based on distribution rates (excluding the discounts for transformer ownership allowance)
   - The Costs include the cost of the Transformer Ownership Allowance
   - The cost of the Transformer Ownership Allowance is allocated to all customer classes

b) In reference (iii) the transformer allowance is allocated directly to the GS>50 class. If the response to part (a) is yes, please explain why in reference (iii) the Cost Allocation Revenue Requirement used to derive the Revenue Requirement wasn't adjusted to remove the allocation of the transformer ownership allowance.

c) Please confirm that (per Exhibit 9, Tab 1, Schedule 1, page 9), CNP-EO is proposing to allocate the cost of the Transformer Ownership Allowance to just the GS>50 class.

d) Please provide the results of an alternative cost allocation run (based on the informational filing data) which is consistent with CNP-EO's proposed treatment of the Transformer Ownership Allowance where:
   - The Revenues by class are based the rates reduced by the transformer ownership allowance where applicable
   - The Costs allocated exclude the "cost" of the Transformer Ownership Allowance.
     (Note: For purposes of the response please just file the revise Output Sheet O1)

RESPONSE:

a) CNPI confirms that the revenues are bases on distribution rates that include the allowance for transformer ownership allowance, the costs include the transformer ownership allowance and that the transformer ownership allowance is allocated to all classes.

b) The revenue requirement by customer class was not modified to remove the allocation of the transformer allowance to the customer classes. CNPI did not, at the time, believe that the allocation across the classes would significantly influence the final outcome of the rate design. CNPI – Eastern Ontario Power will, if so directed, adjust the allocation to the classes to remove the allocation of the transformer allowance.

c) CNPI confirms that in its current Applications, the cost of the transformer ownership allowance is allocated to just the GS>50 class.

d) To proxy the request in this interrogatory, CNPI has removed the transformer allowance costs from Tab I3 Cell F15 of the CNPI-EOP_CostAllocationFiling_20080815.xls. Sheet O1 shown below summarizes the impact of this modification.

2006 Cost Allocation Information Filing
Canadian Niagara Power Inc - Eastern Ontario Power

EB-2005-0346 EB-2007-0001
Thursday, January 18, 2007
Sheet O1 Revenue to Cost Summary Worksheet - Second Run

			1	2	3	7	8	9
Rate Base Assets		**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
crev	Distribution Revenue (sale)	**$1,745,099**	$751,637	$353,701	$623,804	$12,515	$1,458	$1,984
mi	Miscellaneous Revenue (mi)	**$90,493**	$74,319	$21,034	($5,038)	($1,273)	($20)	$1,471
	Total Revenue	**$1,835,592**	**$825,956**	**$374,735**	**$618,766**	**$11,242**	**$1,438**	**$3,455**
	Expenses							
di	Distribution Costs (di)	**$303,417**	$171,860	$36,187	$83,151	$10,797	$1,122	$300
cu	Customer Related Costs (cu)	**$423,517**	$299,566	$74,646	$44,567	$1,828	$377	$2,533
ad	General and Administration (ad)	**$506,006**	$324,148	$76,052	$93,631	$9,251	$1,081	$1,844
dep	Depreciation and Amortization (dep)	**$237,728**	$133,561	$30,127	$64,453	$8,504	$869	$214
INPUT	PILs (INPUT)	**$21,432**	$11,779	$2,745	$6,244	$585	$61	$17
INT	Interest	**$124,600**	$68,479	$15,961	$36,298	$3,404	$356	$101
	Total Expenses	**$1,616,700**	**$1,009,393**	**$235,719**	**$328,344**	**$34,369**	**$3,866**	**$5,009**
	Direct Allocation	**$13,393**	**$9,917**	**$2,511**	**$770**	**$36**	**$15**	**$143**
NI	Allocated Net Income (NI)	**$158,122**	$86,902	$20,255	$46,064	$4,319	$452	$128
	Revenue Requirement (includes NI)	**$1,788,214**	$1,106,213	$258,486	$375,178	$38,724	$4,333	$5,281
		Revenue Requirement Input equals Output						
	Rate Base Calculation							
	<u>Net Assets</u>							
dp	Distribution Plant - Gross	**$5,228,733**	$2,913,435	$633,536	$1,511,082	$150,645	$15,670	$4,365
gp	General Plant - Gross	**$499,513**	$277,507	$62,015	$143,219	$14,799	$1,544	$429
accum dep	Accumulated Depreciation	**($2,662,988)**	($1,488,022)	($314,996)	($775,439)	($74,632)	($7,740)	($2,160)
co	Capital Contribution	**($723,183)**	($414,262)	($81,511)	($197,703)	($26,265)	($2,721)	($720)
	Total Net Plant	**$2,342,075**	**$1,288,658**	**$299,044**	**$681,158**	**$64,547**	**$6,754**	**$1,915**
	Directly Allocated Net Fixed Assets	**$220,523**	**$163,297**	**$41,348**	**$12,680**	**$595**	**$243**	**$2,360**
COP	Cost of Power (COP)	**$6,032,666**	$2,024,118	$1,004,138	$2,988,198	$9,328	$1,252	$5,633
	OM&A Expenses	**$1,232,940**	$795,573	$186,886	$221,349	$21,876	$2,579	$4,677
	Directly Allocated Expenses	**$0**	$0	$0	$0	$0	$0	$0
	Subtotal	***$7,265,605***	***$2,819,691***	***$1,191,023***	***$3,209,547***	***$31,203***	***$3,830***	***$10,310***
	Working Capital	**$1,089,841**	**$422,954**	**$178,653**	**$481,432**	**$4,681**	**$575**	**$1,546**
	Total Rate Base	**$3,652,439**	**$1,874,909**	**$519,045**	**$1,175,270**	**$69,823**	**$7,571**	**$5,821**
		Rate Base Input equals Output						
	Equity Component of Rate Base	**$1,826,219**	**$937,455**	**$259,523**	**$587,635**	**$34,911**	**$3,785**	**$2,910**
	Net Income on Allocated Assets	**$205,500**	**($193,354)**	**$136,505**	**$289,651**	**($23,163)**	**($2,442)**	**($1,697)**
	Net Income on Direct Allocation Assets	**$6,962**	**$5,156**	**$1,305**	**$400**	**$19**	**$8**	**$74**
	Net Income	**$212,462**	**($188,198)**	**$137,810**	**$290,052**	**($23,144)**	**($2,435)**	**($1,622)**
	RATIOS ANALYSIS							
	REVENUE TO EXPENSES %	**102.65%**	74.67%	144.97%	164.93%	29.03%	33.19%	65.43%
	EXISTING REVENUE MINUS ALLOCATED COSTS	**$47,378**	($280,257)	$116,249	$243,587	($27,482)	($2,894)	($1,825)
	RETURN ON EQUITY COMPONENT OF RATE BASE	11.63%	-20.08%	53.10%	49.36%	-66.29%	-64.32%	-55.74%

INTERROGATORY # 7

Ref: Exhibit 9/Tab 1/Schedule 1 (including Appendix A)

a) With respect to pages 13-14, please provide a schedule that sets out the allocation of revenues by customer class based on:
   i. The 2006 approved EDR (i.e., as discussed in the application)
   ii. The 2009 billing determinants at 2008 rates (Note: The rates used should exclude any smart meter rate adder and LV charge. However, the rates and revenues should capture the reduction due to the transformer ownership allowance)

b) With respect to page 16 (line 18), please confirm that the 48.71% represents the residential share of revenue based on 2008 rates/2009 billing determinants. If not, how was it determined?

c) With respect to page 21, please explain why the bill impact for USL is significantly higher using the EDR Approved rates (15.8%) than under a 100% R/C ratio when the R/C ratio is only 65.94% in the EDR-based calculation. A lower R/C ratio should yield lower bill impacts.

RESPONSE:

a) See schedule below:

Canadian Niagara Power - Eastern Ontario Power
Reconciliation of 2009 Revenue Requirement and Actual 2009 Anticipated Revenue

		2009 Volumes		2006 EDR Based Rates		2009 Revenue		
Customer Class	No. of Customers / Connections	kWh	kW	Monthly Service Charge	Volumetric Charge	Monthly Service Charge	Volumetric Charge	Total Class Distribution Revenue
Residential	3,114	29,586,254		22.57	0.0081	843,396	239,649	1,083,044
General Service Less Than 50 kW	415	14,048,011		43.70	0.0206	217,626	289,389	507,015
General Service 50 to 4,999 kW	35	18,614,527	58,180	1,089.42	2.8484	451,020	165,720	616,740
Unmetered Scattered Load	8	94,602		43.70	0.0206	4,195	1,949	6,144
Sentinel Lighting	90	80,618	241	1.63	1.4172	1,760	342	2,102
Street Lighting	597	555,619	1,662	2.39	0.5794	17,108	963	18,071
	4,258	62,979,630	60,084			1,535,105	698,012	2,233,117

Smart meter adders and low voltage adders have been backed out.
Difference between total class revenue and the revenue requirement is due to rounding.

b) 48.71% represents the residential allocation of Base Revenue Requirement with transformer allowance add back found in the Board Approved 2006 EDR and modified to eliminate the General Service 50 to 4,999 kW Time of Use rate class. The derivation of this modified allocation is shown in the CNPI – Eastern Ontario

Power rate design model CNPI-EOP_DxDesign_20080815.xls on Tab 2006 EDR Revenue Distribution and is shown below for reference.

CNPI - Eastern Ontario Power 2006 Board Approved EDR Model
Tab 7-1 Allocation Base Revenue Requirement

Customer Classification	Base Revenue Requirement Allocated (adjusted for Transformer Credit)					
	Overall Allocation to Classes		Variable Component		Fixed Component	
	$	%	$	%	$	%
Residential	751,707	43.07%	166,538	22.15%	585,169	77.85%
General Service Less Than 50 kW	355,718	20.38%	201,768	56.72%	153,950	43.28%
General Service 50 to 4,999 kW	347,212	19.89%	93,298	26.87%	253,914	73.13%
General Service 50 to 4,999 kW - Time of Use	276,650	15.85%	42,381	15.32%	234,268	84.68%
Unmetered Scattered Load	-	0.00%	-		-	
Sentinel Lighting	1,458	0.08%	237	16.27%	1,220	83.73%
Street Lighting	12,516	0.72%	668	5.34%	11,848	94.66%
Totals	1,745,260	100.00%	504,891	28.93%	1,240,369	71.07%
Less Transformer Credit	47,378					
Base Revenue Requirement	1,697,882					

Direct Allocations

Transfer From:			
General Service 50 to 4,999 kW - Time of Use	84,375	6,294	78,082
Transfer To:			
General Service 50 to 4,999 kW	84,375	6,294	78,082
Remaining Balance in			
General Service 50 to 4,999 kW - Time of Use	192,274	36,088	156,187

Allocation of Remaining Balance to All Classes based on their respective shares

Residential	98,415
General Service Less Than 50 kW	46,571
General Service 50 to 4,999 kW	45,458
Unmetered Scattered Load	-
Sentinel Lighting	191
Street Lighting	1,639
Total	192,274

Modified Allocation of Base Revenue Requirement to Eliminate Time of Use

Customer Classification	Base Rvenue Requirement Allocated (adjusted for Transformer Credit)					
	Overall Allocation to		Variable Component		Fixed Component	
	$	%	$	%	$	%
Residential	850,123	48.71%	188,342	22.15%	661,781	77.85%
General Service Less Than 50 kW	402,289	23.05%	228,184	56.72%	174,105	43.28%
General Service 50 to 4,999 kW	477,045	27.33%	128,185	26.87%	348,860	73.13%
General Service 50 to 4,999 kW - Time of Use	-	0.00%	-		-	
Unmetered Scattered Load	-	0.00%	-	56.72%	-	43.28%
Sentinel Lighting	1,648	0.09%	268	16.27%	1,380	83.73%
Street Lighting	14,155	0.81%	756	5.34%	13,399	94.66%
Totals	1,745,260					
Less Transformer Credit	47,378					
Base Revenue Requirement	1,697,882					

c) The allocation consistent with the Board Approved 2006 EDR did not have a separate USL rate class and was therefore billed on a per customer basis using the General Service less than 50 kW rate structure. Therefore, in the exercise to develop rates consistent with the Board Approved 2006 EDR, this same approach was followed and the rate developed was the same as the General Service less than 50 kW class.

The Cost Allocation Informational Filing was allocated to a USL class and was used in the development of the proposed distribution rates. Therefore, the proposed distribution rates for USL, using the Cost Allocation Information Filing, are fundamentally different than the rates that were developed, for comparison, using the Board Approved 2006 EDR distribution of class revenues.

INTERROGATORY # 8

Ref: i) Exhibit 8/Tab 1/Schedule 2, pages 1-3
ii) Exhibit 9/Tab 1/Schedule 1, Appendix A-Cost Allocation Review Tab

a) Please confirm whether or not CNP-EO's Cost Allocation Informational filing included LV Costs as part of the revenue requirement. If yes, please indicate where in the Cost Allocation Informational filing this cost is accounted for.
b) If the response to part (a) is no, why – in Appendix A - are LV costs included in the revenue requirement (I.e., $2,455,575) that is being allocated using the percentages derived from the Cost Allocation Revenue Requirement?

RESPONSE:

a) No, the LV Costs were not included as part of the revenue requirement in CNPI – Eastern Ontario Power's Cost Allocation Informational filing. As shown on Tab I3 TB Data, the revenue requirement used in the Cost Allocation Informational Filing was equal to the approved revenue requirement plus the approved transformer ownership allowance minus the approved low voltage wheeling adjustment.

b) Low voltage wheeling costs were included in the revenue requirement of $2,455,575, which is allocated on TAB [Cost Allocation Review] in column G. The low voltage wheeling allocations to the classes in column J are subtracted from column G to yield the 2009 Base Revenue Requirement less Low Voltage in column K.

The rate design model does remove the low voltage wheeling costs after the determination of the Service Revenue Requirement. The intent was to remove the low voltage wheeling cost; however, mathematically the allocations are slightly different than they would have otherwise been. The table below illustrates the difference had the low voltage not been included as part of the allocated revenue requirement.

Comparison of Proposed Allocations to Allocations with Low Voltage Wheeling Costs Removed				
Customer Class	Allocation of 2009 Base Revenue with Transformer Allowance			
	CNPI – EOP Proposed		As Per this IR	
Residential	1,368,317	61.29%	1,356,375	60.75%
GS < 50 kW	314,475	14.08%	321,517	14.40%
GS > 50 kW	487,288	21.83%	494,618	22.15%
Street Lights	52,156	2.34%	50,187	2.25%
Sentinel Lights	5,519	0.25%	5,334	0.24%
USL	4,946	0.22%	4,673	0.21%
Total	$2,232,702	100%	$2,232,702	100%

Note that there may be slight deviations in the totals shown here due to rounding.

The result is a slightly different allocation to the classes and this methodology can be incorporated in a subsequent rate design.

INTERROGATORY # 9

Ref: Exhibit 9/Tab 1/Schedule 1, Appendix A

a) Based on a recent 12 consecutive months of actual billing data, please indicate the percentage of total residential customers that:
- Consume less than 100 kWh per month
- Consume 100 -> 250 kWh per month
- Consume 250 -> 500 kWh per month
- Consume 500 -> 750 kWh per month
- Consume 750 -> 1000 kWh per month

RESPONSE:

Distribution of Residential Customers based on Monthly Consumption	
Consume less than 100 kWh per month	3.82%
Consume 100 -> 250 kWh per month	5.33%
Consume 250 -> 500 kWh per month	21.91%
Consume 500 -> 750 kWh per month	23.38%
Consume 750 -> 1000 kWh per month	17.57%
Consume > 1000 kWh per month	27.99%

INTERROGATORY # 10

Ref: Exhibit 1/Tab 1/ Schedule 1, p. 4

a) The impact on a residential customer using 1,000 kWh per month is stated to be a 9.4% increase. Please provide the corresponding increase in the distribution component of the total bill.

RESPONSE:

This information is provided in Exhibit 10 Rate Harmonization, Tab 1, Schedule 3 Appendix A, Rate Impacts, of the CNPI-Fort Erie Application. The increase for the Monthly Service Charge and Volumetric Distribution Charge, including the smart meter adder, is 41.2%.

INTERROGATORY # 11

Ref: Exhibit 1/Tab 2/ Schedule 1, p. 6

a) The Application states that 4 of the 6 industrial customers "have either closed or announced closings to take place prior to 2009." Please provide an update as to actual closings and announced closings to date.

RESPONSE:

a) At the time of the Application, August 15, 2008, three of the six customers had already ceased operations. On September 26, 2008 the fourth ceased operations. The remaining two customers in the General Service 50 to 4,999 kW Time of Use continue operations today with their load profiles unchanged from that forecasted in the Application.

INTERROGATORY # 12

Ref: Exhibit 1/Tab 2/ Schedule 1, p. 6

a) Does the Company expect that if the recent decline in the value of the Canadian dollar (against the US dollar) persists, there will be increased customer growth and kWh consumption as a result of higher numbers of US tourists in the service area?

RESPONSE:

As discussed extensively in Exhibit 3, Tab 2, Schedule 1, Gananoque has had minimal growth in population and customers since 2001. In addition, the community has experienced a sharp decline in its industrial sector with the closure of several manufacturing plants.

Further, the generally accepted economic prognostication is one of a protracted decline in the economy. This combination of modest historic growth, even during periods of growth in the general economy, and the current economic decline suggests that it is unlikely that there will be an increase in customer growth and kWh consumption above the forecast put forth by CNPI – Gananoque.

INTERROGATORY # 13

Ref: Exhibit 1/Tab 2/ Schedule 1, p. 7

a) Please explain how the forecast customer growth of 0.3% per year was estimated.

RESPONSE:

In 2005, growth was 0.81%, in 2006 growth was 0.06% and in 2007 growth was 0.03%. The forecasted customer growth of 0.3% is the arithmetic average of the 2005, 2006 and 2007 growth rates.

INTERROGATORY #14

Ref: Exhibit 1/Tab 2/ Schedule 2

a) Please provide the current financial forecast for the next twelve months and five years and the previous five-year forecast (i.e., prepared last year.)

RESPONSE:

Table 1 is CNPI - Eastern Ontario Power's forecast prepared in 2007 for the period 2009 to 2012. Both tables assume CNPI – Eastern Ontario Power rebases in 2009 and again in 2012.

Table 1

2007 Forecast of 2009 to 2012

	Forecasted 2009	Forecasted 2010	Forecasted 2011	Forecasted 2012
Revenue				
Electric revenue	$ 7,718	$ 8,023	$ 8,183	$ 8,344
less purchased power	(5,376)	(5,483)	(5,593)	(5,705)
	2,342	2,540	2,590	2,639
Operating expenses				
Distribution	508	513	518	523
Administrative	585	594	600	607
Customer Service	273	275	278	281
Municipal and other taxes	21	11	5	5
	1,387	1,393	1,400	1,415
Depreciation and amortization	437	456	469	493
Operating income	519	690	721	731
Other income deductions				
Loan interest expense	234	234	234	234
Intercompany interest expense	148	187	191	189
used during construction	(5)	(5)	(5)	(5)
	377	416	420	418
Earnings before income taxes	142	274	301	313
Provision for income taxes				
Current	48	90	99	103
Deferred	-	-	-	-
	48	90	99	103
Net income (loss)	$ 94	$ 184	$ 202	$ 210

Table 2 is CNPI-Eastern Ontario Power's forecast prepared in 2008 for the period 2009 to 2013.

Table 2

2008 Forecast of 2009 to 2013

	Forecasted 2009	Forecasted 2010	Forecasted 2011	Forecasted 2012	Forecasted 2013
Revenue					
Electric revenue	$ 6,508	$ 6,828	$ 6,942	$ 7,211	$ 7,411
less purchased power	(4,430)	(4,519)	(4,609)	(4,702)	(4,796)
	2,077	2,310	2,333	2,510	2,616
Operating expenses					
Distribution	456	465	474	484	494
Administrative	517	527	538	549	560
Customer Service	281	287	293	299	305
Municipal and other taxes	20	9	9	9	9
	1,275	1,288	1,314	1,340	1,367
Depreciation and amortization	432	443	466	498	509
Operating income	370	579	552	671	740
Other income					
Services and miscellaneous revenue	4	4	4	4	4
	4	4	4	4	4
Other income deductions					
Loan interest expense	238	238	238	238	238
Intercompany interest expense	122	142	149	172	189
used during construction	-	-	-	-	-
	359	380	386	410	427
Earnings before income taxes	15	203	170	266	317
Provision for income taxes					
Current	5	65	52	77	92
Deferred	-	-	-	-	-
	5	65	52	77	92
Net income (loss)	$ 10	$ 138	$ 118	$ 189	$ 225

INTERROGATORY # 15

Ref: Exhibit 1/Tab 2/ Schedule 4

a) Please add one additional column to the Table in this Schedule showing 2006 Board approved amounts.

RESPONSE:

REVENUE DEFICIENCY/SUFFICIENCY

Description		2006 Board Approved	2006 Actual	2007 Actual	2008 Bridge Year	2009 Test Year
Distribution Revenue		1,909,143	1,964,266	1,917,002	1,970,139	1,906,646
Operation, Maintenance & Administrative		1,353,721	1,384,512	1,187,999	1,161,845	1,191,875
Depreciation & Amortization		237,728	298,940	356,862	452,930	480,538
Property Taxes		-	603	2,213	5,000	5,000
Capital Taxes (Tax Model Output)		11,055	15,141	15,835	19,800	16,565
Total Costs		1,602,504	1,699,196	1,562,909	1,639,575	1,693,978
Utility Income before Taxes		306,639	265,070	354,094	330,564	212,668
Income tax (Tax Model Output)		11,321	14,337	(249)	2,225	94,858
Utility Income	**A**	295,318	250,733	354,343	328,339	117,810
Rate Base	**B**	3,668,542	5,234,903	5,847,031	7,350,180	7,756,830
Indicated Rate of Return	**C=A/B**	8.05%	4.79%	6.06%	4.47%	1.52%
Approved/Requested Rate of Return	**D**	8.05%	8.05%	8.05%	8.05%	7.36%
(Deficiency)/Sufficiency in Return	**E=C-D**	0.00%	-3.26%	-1.99%	-3.58%	-5.84%
Revenue (Deficiency)/Sufficiency	**F=B*E**	0	(170,676)	(116,343)	(263,350)	(453,093)
Service Revenue Requirement		1,909,143	2,134,943	2,033,345	2,233,489	2,359,739
Less Revenue Offset		(90,495)	(192,636)	(139,947)	(195,882)	(135,927)
Add Low Voltage Wheeling Costs			-	-	273,954	95,837
Base Revenue Requirement		1,818,648	1,942,306	1,893,398	2,311,562	2,319,649

INTERROGATORY # 16

Ref: Exhibit 1/Tab 3/ Schedule 2, p.1

a) Given the low customer growth expected, why are customer deposits expected to increase by 14.9% in 2009 over 2008?
b) Please confirm that the amount due to affiliated parties in 2009 is expected to increase by 7.6% over 2008 (which was 4.8% above 2007).

RESPONSE:

a) The balance of customer deposits for CNPI-Gananoque for 2008 and 2009 represents an estimate only. Although customer growth may be low it is expected that the level of deposits will increase due to changes in deposit practices made in late 2007. Deposits are now required from all new customers. Previously, deposits were only requested from tenants. This change in practice is expected to increase the balance of customer deposits in 2008 and 2009.

b) The amount due to affiliated parties is expected to grow 7.6%. These are cumulative amounts owing to CNPI-Fort Erie and arise due to the fact that all cash is managed at the CNPI-Fort Erie level. For 2009 the Smart Meter expenditures are expected to be approximately $676,000 (see response to OEB # 2) which will contribute significantly to the amount due to affiliated parties.

INTERROGATORY # 17

Ref: Exhibit 2/Tab 1/ Schedule 1, Appendix B

a) Does the Company expect to attain or exceed reliability performance as measured by the three-year averages of SAIDI and of SAIFI in 2008 and in the test year?

RESPONSE:

CNPI – Eastern Ontario Power strives for continuous improvements in reliability performance. Barring any natural disasters or catastrophic system failures, CNPI expects to improve on the 3-year averages for SAIDI and SAIFI in 2008 and 2009.

INTERROGATORY # 18

Ref: i) Exhibit 1/Tab 2/Schedule 4
ii) Exhibit 2/Tab 1/Schedule 3
iii) Exhibit 2/Tab 2/Schedule 3

a) If the rate base for 2008 and 2009 excludes the $1.4M write up, please explain why the difference between the NBV of fixed assets and the rate base narrows considerably in 2008 and 2009.
b) If the rate base for 2008 and 2009 does not exclude the $1.4M write up, please explain why not.

RESPONSE:

a) The rate base for 2008 and 2009 excludes the $1.4M write up in Exhibit 1/Tab 2/Schedule 4 for determining revenue requirements. Exhibit 2/Tab 1/Schedule 3 includes the $1.4M write up for determining materiality.

The reason the difference between the NBV of fixed assets and the rate base narrows considerably in 2008 and 2009 is a result of the following:

- the 2006 Board Approved NBV is based on 2004 historical numbers, therefore the difference between 2006 Board Approved and 2006 Actual is two years of capital expenditures;
- the large difference between the 2006 Actual NBV and the 2007 Actual NBV is primarily due to the addition of a new main substation (see Exhibit 2, Tab 3, Schedule 1, Appendix A, Page 5), and;
- differences between 2007 Actual, 2008 Bridge Year and 2009 Test Year are due to consistent levels of capital expenditures in each of these years, therefore narrowing the gap between the NBV of the fixed assets and the rate base.

b) N/A

INTERROGATORY # 19

Ref: i) Exhibit 2/Tab 2/Schedule 1
ii) Exhibit 2/Tab 3/Schedule 1/Appendix A, p. 12

a) Regarding the truck purchased in 2008 and the derrick purchased in 2009, please indicate (i) whether the equipment that was replaced had any salvage value or the disposal resulted in any revenues for the Company, and (ii) how depreciation and rate base were adjusted to reflect the equipment that was replaced.

RESPONSE:

a) The truck was purchased in 2007 Actual and the derrick in 2008 Bridge Year. There are no vehicle purchases planned in 2009 Test Year. The equipment that was replaced in 2007 is still in use as spare equipment for emergencies. Previously there was only one bucket truck in Gananoque and if that truck was out of service there was no other suitable vehicle to respond to any emergencies. The derrick purchased in 2008 has not yet been received, but is expected to be received before year end, so the unit it is replacing is still in service. Therefore the units being replaced in 2007 and 2008 have not been retired from fixed assets. The NBV of each of the units being replaced is zero so there will be no effect on rate base when they are retired.

INTERROGATORY # 20

Ref: i) Exhibit 2/Tab 3/Schedule 1/Appendix B, pp 5-9
ii) Exhibit 4/Tab 1/Schedule 1. P. 3

a) Please confirm that the SAP improvements described in the first exhibit referenced are being performed by the vendor or an external provider i.e., not by in-house personnel. If unable to so confirm, please explain why the costs are capitalized.

RESPONSE:

The SAP improvements described in this exhibit are being carried out primarily by in-house technical staff. CNPI has developed internal IT competence on both the business and technical aspects of SAP. This enables CNPI to carry out such improvements on a timely and more cost effective basis when compared to using the vendor or external consultants, which benefits the customers. In-house improvements do not affect the warranty or vendor servicing.

The costs associated with SAP improvements are capitalized as they add value to existing SAP system through betterments which enhance the product functionality and/or extend the product's useful life.

INTERROGATORY # 21

Ref: i) Exhibit 2/Tab 4/Schedule 1, page 1
http://www.oeb.gov.on.ca/OEB/_Documents/EB-2004-0205/rpp_price_report_20081015.pdf

a) Please provide an update of the working capital calculation that reflects the most recent OEB Regulated Price Plan Report (page 5) dated October 15, 2008.

RESPONSE:

CNPI - Eastern Ontario Power Original Cost of Power Forecast

	2008			2009		
	Volume		Cost	Volume		Cost
Wholesale Market Service Charge	65,252,488	kWh	420,405	62,979,630	kWh	390,670
Transmission Connection Service Charge	64,474	kW	285,198	60,084	kW	263,298
Transmission Network Service Charge	64,474	kW	317,042	60,084	kW	277,794
Cost of Power	65,252,488	kWh	3,661,588	62,979,630	kWh	3,434,120
LV Charges			273,954			95,837
			4,958,187			4,461,719

CNPI - Eastern Ontario Power Updated Cost of Power

	2009		
	Volume		Cost
Wholesale Market Service Charge	62,979,630	kWh	390,670
Transmission Connection Service Charge	60,084	kW	223,611
Transmission Network Service Charge	60,084	kW	237,245
Cost of Power	62,979,630	kWh	3,799,585
LV Charges			95,837
			4,746,949

a) The table shown above highlights the cost of power calculation details for 2008 and 2009 complete with volumes. The assumed cost of energy was $0.0545 per kWh per the Board's RPP Price Report dated April 11, 2008.

The wholesale transmission rates were based on the following Hydro One approved charges:

Network Service Rate	$2.01/kW
Line and Transformation Service Rate	$1.88/kW

The table on the previous page also shows the updated 2009 cost of power calculation details complete with volumes. The assumed cost of energy was $0.0603 per kWh per the Board's RPP Price Report dated October 15, 2008.

The wholesale transmission rates were based on the following Hydro One pending charges effective January 1, 2009 which are unchanged:

Network Service Rate	$2.01/kW
Line and Transformation Service Rate	$1.88/kW

CNPI – Eastern Ontario Power has also take into account the ongoing variance adjustment calculation anticipated in the OEB Board Staff interrogatory # 66.

Shown below is a recalculated working capital schedule reflecting the most recent OEB Regulated Price Plan Report.

WORKING CAPITAL CALCULATION BY ACCOUNT

	Description	2006 Actual	Allowance for Working Capital	2007 Actual	Allowance for Working Capital	2008 Bridge Year	Allowance for Working Capital	2009 Test Year	Allowance for Working Capital
	Rate Used for Working Capital Allowance		15%		15%		15%		15%
	Power Supply Expenses								
4705	Power Purchased	4,520,784	678,118	4,050,386	607,558	3,661,588	549,238	3,799,585	569,938
4708	Charges-WMS	491,314	73,697	439,035	65,855	420,405	63,061	390,670	58,601
4710	Cost of Power Adjustments	-	-	-	-	-	-	-	-
4712	Charges-One-Time	-	-	-	-	-	-	-	-
4714	Charges-NW	420,223	63,033	367,296	55,094	317,042	47,556	237,425	35,614
4716	Charges-CN	359,406	53,911	302,855	45,428	285,198	42,780	223,611	33,542
4730	Rural Rate Assistance Expense	-	-	-	-	-	-	-	-
4750	Charges - LV	-	-	-	-	273,954	41,093	95,837	14,376
5685	Independent Market Operator Fees and Penalties	-	-	-	-	-	-	-	-
	Power Supply Expenses Total	**5,791,727**	**868,759**	**5,159,572**	**773,936**	**4,958,187**	**743,728**	**4,747,129**	**712,069**
	Distribution Expenses - Operation								
5005	Operation Supervision and Engineering	11,546	1,732	14,309	2,146	31,523	4,728	16,717	2,507
5010	Load Dispatching	1,635	245	-	-	3,557	534	-	-
5012	Station Buildings and Fixtures Expense	1,936	290	2,166	325	5,200	780	8,992	1,349
5014	Transformer Station Equipment - Operation Labour	-	-	-	-	-	-	-	-
5015	Transformer Station Equipment - Operation Supplies and Expenses	-	-	-	-	-	-	-	-
5016	Distribution Station Equipment - Operation Labour	27,133	4,070	9,168	1,375	19,536	2,930	20,194	3,029
5017	Distribution Station Equipment - Operation Supplies and Expenses	5,410	811	5,376	806	-	-	3,600	540
5020	Overhead Distribution Lines and Feeders - Operation Labour	6,623	993	9,707	1,456	22,090	3,313	35,594	5,339
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	18,614	2,792	23,208	3,481	27,400	4,110	26,400	3,960
5030	Overhead Subtransmission Feeders - Operation	-	-	-	-	-	-	-	-
5035	Overhead Distribution Transformers- Operation	104,073	15,611	12,967	1,945	9,621	1,443	11,587	1,738
5040	Underground Distribution Lines and Feeders - Operation Labour	10,398	1,560	14,696	2,204	9,840	1,476	13,758	2,064
5045	Underground Distribution Lines and Feeders - Operation Supplies and Expenses	71	11	735	110	250	38	1,200	180
5050	Underground Subtransmission Feeders - Operation	-	-	-	-	-	-	-	-
5055	Underground Distribution Transformers - Operation	3,284	493	7,317	1,097	1,623	243	4,165	625
5065	Meter Expense	47,545	7,132	49,558	7,434	65,235	9,785	53,174	7,976
5070	Customer Premises - Operation Labour	2,180	327	713	107	2,369	355	592	89
5075	Customer Premises - Materials and Expenses	-	-	2,405	361	400	60	2,400	360
5085	Miscellaneous Distribution Expense	45,174	6,776	58,257	8,739	35,774	5,366	52,383	7,857
5090	Underground Distribution Lines and Feeders - Rental Paid	872	131	779	117	-	-	-	-
5095	Overhead Distribution Lines and Feeders - Rental Paid	50	8	-	-	-	-	-	-
5096	Other Rent	-	-	-	-	-	-	-	-
	Distribution Expenses - Operation Total	**286,543**	**42,981**	**211,361**	**31,704**	**234,418**	**35,163**	**250,755**	**37,613**
	Distribution Expenses - Maintenance								
5105	Maintenance Supervision and Engineering	-	-	23	3	-	-	-	-
5110	Maintenance of Buildings and Fixtures - Distribution Stations	5,214	782	516	77	5,369	805	-	-
5112	Maintenance of Transformer Station Equipment	-	-	-	-	-	-	-	-
5114	Maintenance of Distribution Station Equipment	1,948	292	3,995	599	14,510	2,176	10,692	1,604
5120	Maintenance of Poles, Towers and Fixtures	1,042	156	2,554	383	6,327	949	7,439	1,116
5125	Maintenance of Overhead Conductors and Devices	38,587	5,788	36,323	5,448	30,857	4,629	34,432	5,165
5130	Maintenance of Overhead Services	23,700	3,555	25,866	3,880	20,456	3,068	24,374	3,656
5135	Overhead Distribution Lines and Feeders - Right of Way	41,209	6,181	74,319	11,148	84,975	12,746	86,343	12,951
5145	Maintenance of Underground Conduit	818	123	327	49	-	-	692	104
5150	Maintenance of Underground Conductors and Devices	709	106	1,671	251	-	-	1,783	267
5155	Maintenance of Underground Services	1,185	178	1,054	158	500	75	2,091	314
5160	Maintenance of Line Transformers	16,756	2,513	13,490	2,023	42,941	6,441	16,980	2,547
5175	Maintenance of Meters	23,858	3,579	32,670	4,901	36,215	5,432	20,745	3,112
	Distribution Expenses - Maintenance Total	**155,026**	**23,254**	**192,808**	**28,921**	**242,150**	**36,323**	**205,570**	**30,835**
	Billing and Collection								
5305	Supervision	33,847	5,077	22,491	3,374	21,504	3,226	22,932	3,440
5310	Meter Reading Expense	57,224	8,584	58,391	8,759	54,716	8,207	54,536	8,180
5315	Customer Billing	84,952	12,743	66,422	9,963	72,194	10,829	74,050	11,107
5320	Collecting	32,325	4,849	41,183	6,177	41,239	6,186	53,625	8,044
5325	Collecting- Cash Over and Short	-	-	-	-	-	-	-	-
5330	Collection Charges	-	-	-	-	-	-	-	-
5335	Bad Debt Expense	(10,917)	(1,638)	26,312	3,947	12,000	1,800	14,400	2,160
5340	Miscellaneous Customer Accounts Expenses	88,848	13,327	53,188	7,978	56,765	8,515	49,538	7,431
	Billing and Collection Total	**286,279**	**42,942**	**267,986**	**40,198**	**258,419**	**38,763**	**269,081**	**40,362**
	Community Relations								
5405	Supervision	-	-	-	-	-	-	-	-
5410	Community Relations - Sundry	-	-	-	-	-	-	-	-
5415	Energy Conservation	-	-	-	-	-	-	-	-
5420	Community Safety Program	-	-	718	108	350	53	1,900	285
5425	Miscellaneous Customer Service and Informational Expenses	-	-	-	-	2,100	315	2,100	315
5515	Advertising Expense	-	-	-	-	-	-	-	-
5660	General Advertising Expenses	-	-	233	35	-	-	-	-
	Community Relations Total	**-**	**-**	**951**	**143**	**2,450**	**368**	**4,000**	**600**
	Administrative and General Expenses								
5605	Executive Salaries and Expenses	-	-	-	-	-	-	-	-
5610	Management Salaries and Expenses	-	-	-	-	-	-	-	-
5615	General Administrative Salaries and Expenses	331,584	49,738	313,753	47,063	279,662	41,949	298,529	44,779
5620	Office Supplies and Expenses	23,551	3,533	27,152	4,073	36,230	5,435	29,500	4,425
5625	Administrative Expense Transferred/Credit	(100,960)	(15,144)	(127,128)	(19,069)	(135,078)	(20,262)	(142,974)	(21,446)
5630	Outside Services Employed	23,416	3,512	20,853	3,128	21,321	3,198	22,527	3,379
5635	Property Insurance	19,858	2,979	18,860	2,829	18,659	2,799	19,200	2,880
5640	Injuries and Damages	-	-	-	-	-	-	-	-
5645	Employee Pensions and Benefits	18,349	2,752	86,886	13,033	50,706	7,606	45,833	6,875
5650	Franchise Requirements	-	-	-	-	-	-	-	-
5655	Regulatory Expenses	71,507	10,726	66,296	9,944	52,459	7,869	76,125	11,419
5665	Miscellaneous General Expenses	15,755	2,363	4,907	736	4,500	675	4,650	698
5670	Rent	106,600	15,990	30,000	4,500	27,960	4,194	28,519	4,278
5675	Maintenance of General Plant	147,004	22,051	73,313	10,997	67,988	10,198	80,559	12,084
5680	Electrical Safety Authority Fees	-	-	-	-	-	-	-	-
	Administrative and General Expenses Total	**656,664**	**98,500**	**514,893**	**77,234**	**424,408**	**63,661**	**462,469**	**69,370**
	Taxes								
6105	Taxes Other Than Income Taxes (Note less capital taxes)	603	90	2,213	332	5,000	750	5,000	750
	Taxes Total	**603**	**90**	**2,213**	**332**	**5,000**	**750**	**5,000**	**750**
	Working Capital Allowance Total	**7,176,841**	**1,076,526**	**6,349,783**	**952,468**	**6,125,033**	**918,755**	**5,944,003**	**891,600**

INTERROGATORY # 22

Ref: Exhibit 4/Tab 2/Schedule 4, pp 4-5

a) There is a 79.3% difference between 2006 actual and 2006 Board approved affiliate charges for administrative services that is attributed to "salary increases and the allocations of additional staffing resources." For 2006-2009 inclusive, please provide the total number of staff engaged in providing this service, total salary costs, and the number of said staff that are allocated to CNPI-Gananoque.

RESPONSE:

The total number of staff engaged in providing these services is shown below. The costs allocated include the total of labour and non-labour costs for each department. The total cost to be allocated and the amount and percentage allocated to CNPI - Gananoque is shown below. The 79.6% difference between 2006 actual and 2006 Board Approved is attributable to both increased total costs, including the number of employees and salaries, and the percentage allocated to CNPI - Gananoque. Since 2006 actual, the total costs to be allocated have decreased as well as the amount allocated to CNPI - Gananoque.

Number of Staff Providing Service

CNPI-Fort Erie Departments	**2006 Board Approved**	**2006 Actual**	**2007 Actual**	**2008 Bridge Year**	**2009 Test Year**
Finance	10	8	8	8	8
Information Technology	5	5	5	5	5
Human Resources	2	2	2	1.5	1.5
Health and Safety	2	2	2	2	2
Regulatory	1	2	2	1	1
Property Maintenance and Procurement	3	6	6	4	4
	23	25	25	21.5	21.5

($'000)

Administrative Costs CNPI-FE	**2006 Board Approved**	**2006 Actual**	**2007 Actual**	**2008 Bridge Year**	**2009 Test Year**
Total costs allocated including salary and rent	$ 1,953	$ 2,617	$ 2,540	$ 2,405	$ 2,558
Administrative services and rent provided by CNPI-FE to CNPI-EOP	$ 233	$ 407	$ 362	$ 302	$ 320
percentage of costs allocated to CNPI-EOP	12%	16%	14%	13%	13%

INTERROGATORY # 23

Ref: Exhibit 4/Tab 2/Schedule 5, pages 3-5

a) Please confirm that cost reductions under an IRM plan will only benefit ratepayers if the cost reductions are maintained when the term of the plan expires and the utility's costs are rebased.
b) Please indicate, for President & CEO, Vice-Presidents below 1400 Hay Points, and Other Management, where the actual 2006 and 2007 incentive payments were with respect to the target payouts, i.e., below it, at the target payouts, above the target payouts but below the normal maximum, at the normal maximum, or above the normal maximum.

RESPONSE:

a) CNPI confirms that cost reductions under the IRM plan, established by the OEB, will benefit ratepayers provided the cost reductions are maintained.

b) For 2006 Actual, the President & CEO's short-term incentive payout was above the target payout but below the normal maximum payout amount. For 2007 Actual, the President & CEO's short-term incentive payout was at the normal maximum payout amount.

Fort 2006 Actual and 2007 Actual, on average the Vice-Presidents' payout was above the target payout but below the normal maximum payout amount.

For 2006 Actual and 2007 Actual, on average Other Management/Non-union's payout was above the target payout but below the normal maximum payout amount.

INTERROGATORY # 24

Ref: i) Exhibit 4/Tab 2/Schedule 5/Appendix A
ii) Exhibit 4/Tab 2/Schedule 5/Appendix B

Preamble: *In Appendix A, the 2006 Board Approved allocation of FTEs to CNPI-Gananoque is 8.74 while the 2006 actual is 10.05, an increase of 15.0%; for the 2009 test year, the allocation to CNPI-Gananoque is 9.89, a decrease from 2006 actual but still 13.2% above the 2006 Board approved.*

Appendix B, however, indicates that the total CNPI FTEs approved by the Board for 2006 was 71, while the 2006 actual was 76, an increase of 7.0%; for the 2009 test year, the total FTEs for CNPI is 70, or 1.4% below the 2006 Board approved number.

a) Please explain why the percentage allocation of FTEs to CNPI-Gananoque varies year by year.
b) Please provide the allocation factors used to allocate the FTEs among all of the regulated affiliates for each year 2006-2009.

RESPONSE:

a) The percentage allocation of FTE's to CNPI-Gananoque has remained fixed over the period from 2006 Actual to 2009 Test Year. The percentage allocation has increased from the 2006 Board Approved to the period 2006 Actual to 2009 Test Year as a result of additional staffing in customer service, engineering and property and procurement services that were required to meet business needs of CNPI-Gananoque. On an aggregate basis for all service territories, CNPI FTE's have decreased from 2006 Board Approved to 2009 Test Year. Furthermore, because we are dealing with such a small number of employees, a change of one or two employees has a dramatic increase on the percentage which may not be representative of overall staffing of CNPI. (i.e. a change from 8.74 in 2006 Board Approved to 9.89 in 2009 Test Year is a 13.2% increase but represents an actual increase of only 1.1 total employees.)

b) Allocations are based on the cost allocation methodology as set out in the BDR Report (Exhibit 4, Tab 2, Schedule 4, Appendix B, page 12). This is summarized in the chart below:

	FE	**PC**	**EOP**
TOTAL	29%	17%	8%

INTERROGATORY # 1

Ref: Exhibit 1/Tab 1/Schedule 16

Please identify exactly how CNP-FE has complied with the Board Order EB-2007-0514 with respect to removing assets from rate base, updating its depreciation expense, and adjusting net fixed assets as a result of damages due to the October 2006 Natural Disaster. Please provide all specific references in the current filing that address this issue.

RESPONSE:

Upon investigating this matter it was discovered that due to the immediate nature of the disaster recovery response surrounding the October 2006 Natural Disaster, the paperwork required for the retirement of the assets was never received and processed. It is estimated that the NBV of the assets is $25,000. They will be retired from assets by the end of 2008.

INTERROGATORY #2

Ref: Exhibit 1/Tab 2/Schedule 1, page 5, lines 10-12

Regarding "the impact of capitalization of works" that the PEG Report "does not consider,"

a) Please confirm that the inference to be drawn is that CNP-FE undercapitalizes costs relative to its peers, thus inflating its operating expenses. If unable to so confirm, please explain.
b) Please provide percentages of O&M costs capitalized for CNP-FE along with the average percentage of O&M costs capitalized by its peers.

RESPONSE:

a) CNPI-FE does not mean to infer that it undercapitalizes costs relative to its peers.

CNPI-FE does believe there are a wide range of capitalization policies amongst the LDCs making the comparison of operating expenditures on a stand alone basis more challenging.

There are many factors that could affect the level of capitalization. A circumstance that would increase operating expenditures at CNPI-FE is the rental of its service centre. For many LDCs, the service centre would be owned and associated costs are included in the cost of capital and depreciation expense. In the case of CNPI - FE, the rent paid for its service centre is an operating expense which would not be capitalized.

b) CNPI-FE will capitalize approximately 9% of O&M costs as capitalized overhead in 2009 Test Year. CNPI is not aware of the percentage of O&M costs capitalized by its peers.

INTERROGATORY # 3

Ref: i) Exhibit 1/Tab 2/Schedule 1, page 14
ii) Exhibit 2/Tab 1/Schedule 1/Appendix A, lines 9-10

Please indicate CNP-FE's current plans regarding obtaining authorization to conduct smart metering activities and install smart meters in 2009.

RESPONSE:

CNPI is part of the Niagara Erie Power Association (NEPA), a consortium comprising nine utilities in the Niagara Region that is pursuing a collective approach to Smart Meter/Automated Meter Infrastructure (AMI) implementation. NEPA engaged the services of Util-Assist, Inc. to facilitate the process, a service that Util-Assist is also providing to other utility consortiums in Ontario working towards Smart Meter/AMI implementation. NEPA has prepared technical and economic models for evaluating Smart Meter/AMI suppliers and installers and temporary Operational Data Storage (ODS) providers. Pursuant to O. Reg. 427/06, NEPA "piggybacked" on the London Hydro RFP process for selecting a Smart Meter/AMI supplier. The evaluation process was facilitated by London Hydro and overseen by a Fairness Commissioner authorized by the Ministry of Energy. As a result of this process, Sensus Technologies was selected as the Smart Meter/AMI supplier for the NEPA consortium. Progress to date on Smart Meter/AMI implementation can be summarized as follows:

- Sensus selected as Smart Meter/AMI supplier. Contract expected to be signed by December 31, 2008.
- Proposals for Installation services are currently being evaluated and a decision will be made after such evaluation.
- RFP issued for temporary ODS services.

By "piggybacking" on the London Hydro RFP process in accordance with the provisions of O. Reg. 427/06, the NEPA consortium and CNPI is authorized by the Ministry of Energy to deploy Smart Meters/AMI. CNPI plans to commence deployment in July 2009.

INTERROGATORY # 4

Ref: Exhibit 2/Tab 2/Schedule 1

With respect to the allocations shown under Gross Fixed Assets and Accumulated Depreciation for each year 200-2009:

a) Was the same allocation percentage used across all four years?
b) Was the same allocation methodology applied to each account for all four years?
c) Please describe the allocation factor that is currently used for each account.

RESPONSE:

a) Yes. Please see the response to Question VECC-PC-07(a).

b) Yes. Please see the response to Question VECC-PC-07(a).

c) Please see the response to Question VECC-PC-07(a).

INTERROGATORY # 5

Ref: Exhibit 2/Tab 3/Schedule 1/Appendix A

a) Regarding New Service Lines (page 10), please indicate the number of new customers and number of upgrades to existing services associated with the spending in each year.
b) Regarding New Meters (page 12), please indicate the number of new customers and number of replacements of existing meters associated with the spending in each year.
c) With respect to Major Underground Projects (page 17), please indicate whether the project has lowered the maintenance costs for the test year. If so, please quantify the savings. If not, please explain why not.

RESPONSE:

(a) The requested information is presented in the table below.

Year	2006	2007	2008 YTD
New services	157	243	170
Upgraded services	177	232	131

(b) The requested information is presented in the table below. The exact number of new meters installed on new services is unknown, but it is estimated that new meters are installed on about 50% of new services, while the rest of new services are serviced with reverified meters. Quantities shown for total new meters purchased are exact, because CNPI is aware of the total purchase requirements.

Year	2006	2007	2008 YTD
New meters installed on new services (estimated)	80	120	25
New meters installed on existing services (estimated)	220	1100	8
Total New Meters	300	1220	33

(c) The Major Underground Projects identified in the Application have not lowered maintenance costs for 2009 Test Year. This is because the quantity of overhead plant that will be replaced is negligible compared to the overall overhead system and also because the existing overhead facilities were in reasonably good condition. Thus, maintenance savings – if any – due to these projects would be insignificant compared to overall maintenance budgets.

INTERROGATORY # 6

Ref: Exhibit 2/Tab 4/Schedule 1, page 1

With respect to Power Supply Expenses:

a) Please provide a schedule that sets out, for each expense in 2008 and 2009, the volumes, the assumed rate, and the total costs;
b) Please update the calculation to reflect (i) the approved wholesale transmission rates as of January 1, 2009 and (ii) the forecast cost of power as presented in the Board's RPP Price Report released on October 15, 2008.

RESPONSE:

CNPI - Fort Erie Original Cost of Power Forecast

	2008			2009		
	Volume		Cost	Volume		Cost
Wholesale Market Service Charge	299,924,558	kWh	1,863,017	304,156,931	kWh	1,883,818
Transmission Connection Service Charge	400,159	kW	1,326,735	408,338	kW	1,319,034
Transmission Network Service Charge	400,159	kW	1,408,114	408,338	kW	1,326,338
Cost of Power	299,924,558	kWh	16,226,274	304,156,931	kWh	16,559,371
			20,824,140			21,088,561

CNPI - Fort Erie Updated Cost of Power

	2009		
	Volume		Cost
Wholesale Market Service Charge	304,156,931	kWh	1,883,818
Transmission Connection Service Charge	408,338	kW	1,459,652
Transmission Network Service Charge	408,338	kW	1,513,411
Cost of Power	304,156,931	kWh	18,321,653
Total			23,178,534

a) The table shown above highlights the cost of power calculation details for 2008 and 2009 complete with volumes. The assumed cost of energy was $0.0545 per kWh per the Board's RPP Price Report dated April 11, 2008.

The wholesale transmission rates were based on the Board approved charges;

Network Service Rate	$2.31/kW
Line and Transformation Service Rate	$2.20/kW

b) The table on the previous page also shows the updated 2009 cost of power calculation details complete with volumes. The assumed cost of energy was $0.0603 per kWh per the Board's RPP Price Report dated October 15, 2008.

The wholesale transmission rates were based on the Board approved charges effective January 1, 2009;

Network Service Rate	$2.57/kW
Line and Transformation Service Rate	$2.32/kW

CNPI – Fort Erie has also take into account the adjustment to anticipated in the OEB Board Staff interrogatory # 68, the ongoing variance adjustment calculation.

INTERROGATORY # 7

Ref: Exhibit 3/Tab 1/Schedule 2, page 1

a) Please confirm whether the rates used to determine the 2009 revenues by customer class:
   - Excluded the smart meter rate adder
   - Were reduced to reflect the transformer ownership allowance, where appropriate.

b) Please reconcile the Distribution revenues reported here for 2009 with the Base Revenue Requirement reported at Exhibit 9/Tab 1/Schedule 1, page 6.

c) Please reconcile the Distribution Revenues reported here for 2009 (by customer class) with those reported in the Rate Design Model (Reconciliation of 2009 Rates tab).

RESPONSE:

a) CNPI – Fort Erie confirms that the rates used to determine the 2009 revenues by customer class excluded the smart meter adder and were reduced by the transformer ownership allowance as appropriate.

b) During an attempt to reconcile the distribution revenues reported here for 2009 with the Base Revenue Requirement reported at Exhibit 9/Tab 1/Schedule 1, page 6 an error was found in the Rate Design Model. The genesis of the error is on Tab “DxRates 2006 EDR Distributions” in cells C10 to D15. The volumes in kWh and kW have been calculated as the average of the 2008 Bridge Year and the 2009 Test Year volumes which was in error.

   These cells should contain the 2009 forecasted volumes. Effectively this error has understated the volumes and subsequently overstated the rates.

   This will be corrected in a subsequent rate design model and will factor any other issues arising in the interrogatory phase of the review, for example the recalculation of retail transmission rates.

c) Same as b) above

INTERROGATORY # 8

Ref: Exhibit 3/Tab 2/Schedule 1, pages 2-5

a) Please provide a schedule that sets out:
   - the kWh per customer for the Residential, GS<50 and GS>50 customer classes based on the Hydro One Weather Normalized data (per page 2, lines 29-30).
   - The kWh per customer class for the Residential, GS<50 and GS>50 customer classes (for the same year) using CNP-FE's weather normalization methodology.

b) The CNP-FE weather normalization methodology is based on the premise that that the mix of weather sensitive and non-weather sensitive loads for CNP-FE is a reasonable subset of the overall IESO controlled grid. For weather sensitive load, the IESO normalization methodology captures the weather impacts across the entire province and, in doing so, reflects not only the weather across the entire province and reflects the amount of weather sensitive load (e.g., space heating and space cooling) in each customer class.
   - Why is it reasonable to assume that, for weather sensitive loads, the weather adjustment for CNP-FE would be the same as for the province as a whole? Are the heating and cooling degree days in CNP-FE similar to those for the province as a whole? Is the saturation of space heating and cooling appliances the same in CNP-FE as it is for the province as whole?

c) The table on page 4 (line 14) only compares 30 years of weather data for CNP-FE with that for the years 2005, 2006 and 2007. Please explain how this comparison supports applying the weather correction factor derived from the IESO provincial data to the CNP-FE data.

d) With respect to the table of page 4 (line 14), the impact of a heating degree day on electricity load will be different than the impact of a cooling degree day (i.e., each will depend respectively on the extent of installation of electric space heating and cooling equipment).
   - Please explain why it is reasonable to compare the sum of the mean heating and cooling days.
   - Please confirm that what the table shows is that for the period 2005-2007, the heating degree days were all lower than the 30 year average while the cooling degree days were all higher.

RESPONSE:

a) The table shown below shows the 2004 data from the Cost Allocation Informational Filing, the Hydro One Weather Normalized data from the same filing and the 2004 data normalized using CNPI methodology used in this Application.

Comparison of Weather Normalization Data			
Class	Actual Data (kWh)	Hydro One Normalized Data (kWh)	CNPI Methodology (kWh)
Residential	112,747,739	122,290,227	112,959,034
GS < 50 kW	42,674,415	40,307,256	42,754,389
GS > 50 kW	145,569,210	127,055,036	145,665,810

The IESO correction factor as calculated consistent with the methodology used by CNPI was a 0.13% adjustment upward.

The Hydro One normalized data shows a great deal of volatility between actual sale data and the normalized data. CNPI has not seen this level of volatility in its sales year over year other than events associated with discrete activities such as customer closures.

b) Notwithstanding the discussion of the points raised in the question, CNPI suggests that the IESO weather correction formulation is a reasonable proxy to use in the Application.

For all electricity distribution companies, throughput and demand will be changing constantly in response to a number of external factors including customer additions and deletions, weather conditions, customer behaviour and industrial commercial activity. In smaller utilities, like CNPI, where there is limited diversity in its customer base, response to these factors maybe often skewed in response to singular events. For example the behavior of the embedded generators in CNPI – Port Colborne to gas price signals, industrial closures in Port Colborne and Gananoque and residential customer behavior in response to these externalities. Weather normalization is only one of many variables that have to be considered.

CNPI suggests that the IESO 18 Month Outlook: Ontario Demand Forecast is a reasonable barometer of the electrical system response to a wide range of variables in the economy and is the better choice for normalizing the throughput data of a smaller LDC like CNPI.

c) CNPI – Fort Erie has included this information only to illustrate the correlation between the total mean degree days and the normalizing adjustment factors develop the normalized throughput. Comparing the values for 2005 and 2006 shows a reduction in the number of mean degree days likewise the adjustment factor developed in this Application has reduced the throughput.

d) Again, as discussed in part c), this was developed to show that a correlation existed in the trend of total mean degree days and the adjustments being made to throughput. As well, this information supports the notion that none of these years were extreme weather years.

CNPI confirms that the data presented in this table shows that for the period 2005-2007, the heating degree days were all lower than the 30 year average while the cooling degree days were all higher.

INTERROGATORY # 9

Ref: Exhibit 3/Tab 2/Schedule 1, page 6

a) Please confirm whether the reference to Port Colborne at line 2 is correct.

RESPONSE:

Yes, the reference to Port Colborne is correct. The operating territories of CNPI – Fort Erie and CNPI – Port Colborne are contiguous.

INTERROGATORY # 10

Ref: Exhibit 3/Tab 2/Schedule 1, pages 8-10

a) Please provide the Residential and GS<50 customer counts for each year from 2002 to 2007.
b) The Application makes reference to 'normalized average use per customer" for the Residential (page 8, line 9) and GS<50 (page 9, line 16) classes. Please describe how the weather normalized Residential and GS<50 usage values were derived.
c) What is the impact of eliminating long term load transfers on CNP-FE's customer count (page 9)?

RESPONSE:

a) This information is provided in the Application, Exhibit 9 Tab 1 Schedule 1 Appendix A Rate Design Model.

   Restated here the counts are:

Class	2002	2003	2004	2005	2006	2007
Residential	13,394	13.500	13,717	13,818	13,919	14,073
GS < 50 kW	1,090	1,082	1,150	1,164	1,168	1,170

b) The matter of "normalized average use per customer" is discussed fully in the response to VECC-FE Interrogatory # 8.

c) Preliminary discussions with Niagara Peninsula Energy indicates that there will be no rate impact of eliminating long term load transfers on CNP-FE's customer count.

INTERROGATORY # 11

Ref: Exhibit 3/Tab 2/Schedule 1, pages 10-12

a) Please breakdown the schedule provided on page 10 into two separate schedules as follows:
   - One schedule for the four largest customers in the GS>50 class, and
   - A second schedule for the balance of the customer in the GS>50 class.

RESPONSE:

GS > 50 kW (4 Largest Customers)	2005	2006	2007
Number of Customers	4	4	4
Percent Change in Customers			
Kilowatt-hours Sold	51,847,759.0	56,024,171.0	53,655,526.3
Average Use per Customer	12,961,939.8	14,006,042.8	13,413,881.6
Kilowatts Sold	97,968.00	110,502.00	108,970.56
Average Demand per Customer	24,492.00	27,625.50	27,242.64

GS > 50 kW (All)			
Number of Customers	139	134	141
Percent Change in Customers	4.51%	-3.60%	5.22%
Kilowatt-hours Sold	140,488,743	133,812,631	142,072,764
Average Use per Customer	1,010,710	998,602	1,007,608
Kilowatts Sold	370,913	345,357	383,911
Average Demand per Customer	2,668	2,577	2,723

GS > 50 kW (Balance)			
Number of Customers	135	130	137
Percent Change in Customers	4.51%	-3.60%	5.22%
Kilowatt-hours Sold	88,640,984.0	77,788,460.0	88,417,237.7
Average Use per Customer	656,599.9	598,372.8	645,381.3
Kilowatts Sold	272,945.3	234,855.0	274,940.4
Average Demand per Customer	2,021.8	1,806.6	2,006.9

INTERROGATORY # 12

Ref: i) Exhibit 4/Tab 2/Schedule 5/Appendix A
ii) Exhibit 4/Tab 2/Schedule 5/Appendix B
iii) Exhibit 4/Tab 2/Schedule 4/Appendix B

a) Please explain why, in 2006, although actual FTEs for CNPI exceeded the Board approved number by 7%, the allocation of FTEs to CNP-FE was less than the Board approved number by 4.6%.
b) Please explain why in 2009, although the total CNPI FTEs are almost the same as the 2006 Board approved number (70 versus 71 or a 1.4% decrease), the allocation to CNP-FE in 2009 is 15.6% lower.

RESPONSE:

a) The increase in total FTE's of 7% in 2006 Actual over 2006 Board Approved was the result of net additional staffing over the 2004 to 2006 period. The decrease in FTEs allocated to CNPI-FE by 4.6% was the result of a decrease in the allocation of staffing to CNPI-FE compared to the allocation used in the 2006 Board Approved figure. This was a result of slightly higher staff allocations to CNPI-PC and CNPI-GAN in the areas of customer service, operations, engineering and property and procurement in order to meet business needs. Because CNPI-FE is dealing with a small number of employees, a change of 1.76 employees has a dramatic affect on the percentage change, which is 4.6%. Since 2006 Board Approved, CNPI has had a net decrease in the total number of employees.

b) As noted above in (a), since 2006 Board Approved, CNPI has had a net decrease in total number of employees as well as a decease in the percentage allocated to CNPI-FE. The 15.6% decrease in FTE allocation to CNPI-FE from 2006 Board Approved to 2009 Test Year is a result of a decrease in the allocation of staffing to CNPI-FE compared to the allocation used in the 2006 Board Approved figure.

INTERROGATORY #13

Ref: Exhibit 4/Tab 2/Schedule 6, page 3

The tables on this page are based on the assumption that 25% of labour being capitalized.

a) Is this assumption consistent with CNP-FE's O&M capitalization policy?
b) Does CNP-FE know what assumptions are made for other utilities in its peer group for the purpose of calculating pension expenses?

RESPONSE:

a) CNPI - Fort Erie does not have a specified percentage allocation with respect to the capitalization of labour. CNPI's policy is to capitalize labour, as required, to complete capital projects. For the period 2006 to 2009 as outlined in the referenced table, CNPI has capitalized approximately 25% of total labour through direct charges to capital projects.

b) CNP – Fort Erie is not aware of what assumptions other utilities in its peers group use for the purpose of calculating pension expense. CNPI-FE relies on the expertise and advice of the company's actuary, Mercer's Human Resource Consulting. The assumptions are reviewed for reasonableness annually by Ernst & Young as part of the external audit process.

INTERROGATORY # 14

Ref: i) Exhibit 4/Tab 2/Schedule 2
ii) Exhibit 4/Tab 1/Schedule 1, page 2

a) Is the $18,967 regulatory expense recovery included in Account No. 5655? If so, why are there no regulatory savings expected in 2009 compared to 2008?
b) If the regulatory expense recovery is not in Account 5655, please indicate where it is.

RESPONSE:

a) The 2009 regulatory expense account (Account No. 5655) includes the rate rebasing expense recovery of $18,967. The increase in the 2009 regulatory expense account over 2008 is a result of the rate rebasing expense recovery.

b) Refer to answer in part a).

INTERROGATORY # 15

Ref: i) Exhibit 4/Tab 2/Schedule 2
ii) Exhibit 4/Tab 2/Schedule 3/Appendix A, page 3

Please explain the variance between 2006 Board Approved costs and 2006 Actual costs for Maintenance of Meters in Account No. 5175.

RESPONSE:

There was a variance of $59,811 between 2006 Board Approved costs and 2006 Actual costs in this account. This occurred because in 2006 CNPI was obligated to address the backlog of meter reverifications for Measurement Canada requirements. This resulted in increased meter changeout activity for meter reverification purposes.

INTERROGATORY # 16

Ref: Exhibit 4/Tab 2/Schedule 4, page 4

a) For each year 2006-2009 inclusive, please provide the total corporate services costs of FortisOntario that were allocated and the percentage allocated to CNP-FE.
b) For each year 2006-2009 inclusive, please provide the total corporate services costs of Fortis Inc. that were allocated and the percentage allocated to CNP-FE.
c) For each year 2006-2009 inclusive, please provide the total interest expense costs from FortisOntario that were allocated and the percentage allocated to CNP-FE.
d) For each year 2006-2009 inclusive, please provide the total interest expense costs from Cornwall Electric that were allocated and the percentage allocated to CNP-FE.

RESPONSE:

($'000)

		2006 Board Approved	2006 Actual	2007 Actual	2008 Bridge Year	2009 Test Year
a)	**Corporate services FortisOntario**					
	Corporate services costs	$ 1,776	$ 1,509	$ 1,509	$ 1,510	$ 1,477
	Percentage allocation to CNP-FE	27.0%	30.0%	18.0%	20.0%	20.0%
	Allocation to CNPI-FE	$ 479	$ 453	$ 272	$ 302	$ 295
b)	**Corporate services Fortis Inc.**					
	Corporate services costs	$ -	$ 159	$ 137	$ 150	$ 170
	Percentage allocation to CNP-FE	0.0%	32.1%	32.1%	30.0%	30.0%
	Allocation to CNPI-FE	$ -	$ 51	$ 44	$ 45	$ 51
c)	**Interest costs from FortisOntario**					
	Total Interest costs to CNPI	69	154	381	650	1,103
	Percentage allocation to CNP-FE	100.0%	100.0%	52.5%	53.1%	52.6%
	Allocation to CNPI-FE	$ 69	$ 154	$ 200	$ 345	$ 581
d)	**Interest costs from Cornwall Electric**					
	Total CE interest costs to CNPI	83	302	413	219	-
	Percentage allocation to CNP-FE	100.0%	100.0%	52.5%	53.4%	0.0%
	Allocation to CNPI-FE	$ 83	$ 302	$ 217	$ 117	$ -

INTERROGATORY # 17

Ref: Exhibit 4/Tab 2/Schedule 5

a) Please provide the total incentive payments for 2006 and 2007 and indicate the amount that was deemed to be "primarily shareholder related."

RESPONSE:

a) The total incentive payment included in CNPI's rate Applications for all three service territories for 2006 is $202,285. The portion allocated to CNPI-FE for 2006 is $107,843. The total incentive payment included in CNPI's rate Applications for all three service territories for 2007 is $209,190. The portion allocated to CNPI-FE for 2007 is $111,466. The incentive payments in the Applications do not include any component that is "primarily shareholder related".

INTERROGATORY # 18

Ref: Exhibit 8/tab 1/Schedule 1

a) With reference to the comment on page 3 that CNP-FE's customer profile has not changed significantly, please complete the following table:
   - kWh by Customer Class (delivered)
   - Customer/Connection Count

b) Based on the results from part (a), please comment on the appropriateness of assuming that the revenue requirement proportions from the Updated 2006 Cost Allocation study can be used for setting 2009 rates.

RESPONSE:

a) The information provided below has been extracted from information filed in the Application. Information related to the Cost Allocation Informational Filing has been extracted from Sheet I6, Customer Data Worksheet – Second Run, of the 2006 Cost Allocation Informational Filing for CNPI – Fort Erie, EB-2005-0344. Information relating to the 2009 Application has been extracted from the Application, Exhibit 3 Tab 2 Schedule I Appendix A, found on page 357 of the Application.

Customer Class (all)	Cost Allocation Filing		2009 Application	
	kWh	% of Total	kWh	% of Total
Residential	112,747,739	37.0%	115,322,011	37.9%
GS < 50	42,674,415	14.0%	37,747,136	12.4%
GS > 50	145,569,210	47.8%	147,729,800	48.6%
Street Light	2,339,029	0.8%	2,210,842	0.7%
Sentinel	863,072	0.3%	797,374	0.3%
USL	318,026	0.1%	349,768	0.1%
Total	304,511,491	100.0%	304,156,931	100.0%

Customer Class (all)	Cost Allocation Filing		2009 Application	
	Number	% of Total	Number	% of Total
Residential	13,717	72.2%	14,315	72.2%
GS < 50	1,150	6.1%	1,184	6.0%
GS > 50	133	0.7%	147	0.7%
Street Light	3,020	15.9%	3,095	15.6%
Sentinel	862	4.5%	961	4.8%
USL	107	0.6%	119	0.6%
Total	18,989	100.0%	19,821	100.0%

In the Cost Allocation Informational Filing, the number of connections for street lights, sentinel lights and unmetered scattered load were modified, using engineering judgment to reflect the number of physical connections to the distribution system. For purposes of this exercise these values have been replaced with the number of connections reported in the Board Approved 2006 EDR, the basis for the Cost Allocation Informational Filing.

b) It is CNPI – Fort Erie's position that the proportions have not change significantly and the 2006 Cost Allocation study can be used for setting 2009 rates.

INTERROGATORY # 19

Ref: Exhibit 8/Tab 1/Schedule 2, pages 1-3

a) Please explain why CNP-FE is proposing to move the Revenue to Cost ratio for USL further away from 100% (i.e. from 56.76% to 56.35%).
b) Please explain why the revenue to cost ratio for Street Lighting is only being increased by 22% when the ratio for Sentinel Light (which is closer to 100% to start) is being increased by 42% (i.e., 53.09/37.35 = 42% increase).

RESPONSE:

a) Notwithstanding the fact that the Revenue to Cost Ratio for USL has moved further away from 100% class recovery, the allocation of Base Revenue Requirement for USL has increased from 0.22% to 0.26% or from $20,355 to $24,334. As a result, CNPI – Fort Erie has increased the dollar value allocated to the USL class by $3,979 or 20%.

   The mitigating factor becomes the total bill impact. In designing rates that limit total impact to 10% for any given class, there is a finite amount of revenue requirement that can be assigned to the class when growth in that class is limited. With the finite growth and the allocation of the increased Base Revenue Requirement it is not practical to maintain the existing Revenue to Cost Ratio and respect the total bill impact.

b) As was discussed in part a), an increase in the Revenue to Cost Ratio has a direct correlation on the overall bill impacts. The amount of additional Base Revenue Requirement allocated to any class has been limited, in the rate design, by the notion of the total bill impact not exceeding 10% for any class.

   CNPI – Fort Erie increased each of these classes' allocation of Base Revenue Requirement as was possible in order to approach the Board's guidelines and yet respect the total class bill impact of 10%.

INTERROGATORY # 20

Ref: i) Exhibit 8/Tab 1/Schedule 2, page 3
ii) Exhibit 9/Tab 1/Schedule 1, page 9, lines 2-6
iii) CNP-FE's Rate Design Model – Cost Allocation Review Tab

a) Please confirm that for purposes of the Cost Allocation Informational Filing:
   - The Revenues are based on distribution rates (excluding the discounts for transformer ownership allowance)
   - The Costs include the cost of the Transformer Ownership Allowance
   - The cost of the Transformer Ownership Allowance is allocated to all customer classes

b) In reference (iii) the transformer allowance is allocated directly to the GS>50 class. If the response to part (a) is yes, please explain why in reference (iii) the Cost Allocation Revenue Requirement (2nd column) used to derive the Revenue Requirement by customer class wasn't adjusted to remove the allocation of the transformer ownership allowance.

c) Please confirm that (per Exhibit 9, Tab 1, Schedule 1, page 9), CNP-FE is proposing to allocate the cost of the Transformer Ownership Allowance to just the GS>50 class.

d) Please provide the results of an alternative cost allocation run (based on the January 2007 informational filing data) which is consistent with CNP-FE's proposed treatment of the Transformer Ownership Allowance where:
   - The Revenues by class are based the rates reduced by the transformer ownership allowance where applicable
   - The Costs allocated exclude the "cost" of the Transformer Ownership Allowance.
     (Note: For purposes of the response please just file the revise Output Sheet O1)

RESPONSE:

a) CNPI confirms that the revenues are based on distribution rates that include the allowance for transformer ownership allowance, the costs include the transformer ownership allowance and that the transformer ownership allowance is allocated to all classes.

b) The revenue requirement by customer class was not modified to remove the allocation of the transformer allowance to the customer classes. CNPI did not, at the time, believe that the allocation across the classes would significantly influence the final outcome of the rate design. CNPI – Fort Erie will, if so directed, adjust the allocation to the classes to remove the allocation of the transformer allowance.

c) CNPI confirms that in its current Applications the cost of the transformer ownership allowance is allocated to just the GS>50 class.

d) To proxy the request in this interrogatory, CNPI has removed the transformer allowance costs from Tab I3 Cell F15 of the CNPI-FE_CostAllocationFiling_20080815.xls. Sheet O1 shown below summarizes the impact of this modification.

2006 Cost Allocation Information Filing
Canadian Niagara Power Inc - Fort Erie

EB-2005-0344 EB-2007-0001
Thursday, January 18, 2007

Sheet O1 Revenue to Cost Summary Worksheet - Second Run

Rate Base Assets		Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
crev	Distribution Revenue (sale)	**$8,065,671**	$4,043,487	$1,179,542	$2,742,200	$57,530	$25,050	$17,862
mi	Miscellaneous Revenue (mi)	**$427,411**	$306,973	$55,666	$50,723	$3,425	$861	$9,761
	Total Revenue	**$8,493,082**	**$4,350,460**	**$1,235,208**	**$2,792,923**	**$60,955**	**$25,911**	**$27,623**
	Expenses							
di	Distribution Costs (di)	**$1,510,116**	$877,323	$164,767	$372,791	$74,924	$16,289	$4,022
cu	Customer Related Costs (cu)	**$977,491**	$761,962	$121,874	$75,093	$272	$116	$18,175
ad	General and Administration (ad)	**$1,881,869**	$1,230,205	$216,079	$347,708	$59,042	$12,877	$15,958
dep	Depreciation and Amortization (dep)	**$1,446,922**	$828,282	$155,785	$387,597	$59,148	$12,936	$3,174
INPUT	PILs (INPUT)	**$141,939**	$82,764	$15,549	$35,168	$6,652	$1,448	$359
INT	Interest	**$1,053,934**	$614,541	$115,454	$261,129	$49,393	$10,749	$2,668
	Total Expenses	**$7,012,271**	**$4,395,076**	**$789,508**	**$1,479,485**	**$249,431**	**$54,415**	**$44,355**
	Direct Allocation	**$37,179**	**$29,152**	**$4,889**	**$1,978**	**$19**	**$7**	**$1,134**
NI	Allocated Net Income (NI)	**$1,337,480**	$779,874	$146,515	$331,382	$62,682	$13,641	$3,386
	Revenue Requirement (includes NI)	**$8,386,929**	$5,204,102	$940,912	$1,812,845	$312,132	$68,063	$48,875
		Revenue Requirement Input equals Output						
	Rate Base Calculation							
	Net Assets							
dp	Distribution Plant - Gross	**$36,519,553**	$21,144,225	$3,971,471	$9,356,445	$1,609,923	$350,990	$86,499
gp	General Plant - Gross	**$4,915,983**	$2,865,122	$537,028	$1,221,735	$229,708	$49,996	$12,393
accum dep	Accumulated Depreciation	**($14,057,285)**	($8,052,816)	($1,517,665)	($3,774,053)	($560,333)	($122,548)	($29,871)
co	Capital Contribution	**($1,473,997)**	($852,611)	($153,856)	($384,139)	($65,614)	($14,307)	($3,470)
	Total Net Plant	**$25,904,254**	**$15,103,920**	**$2,836,978**	**$6,419,989**	**$1,213,684**	**$264,132**	**$65,551**
	Directly Allocated Net Fixed Assets	**$528,199**	**$414,161**	**$69,458**	**$28,100**	**$264**	**$106**	**$16,110**
COP	Cost of Power (COP)	**$20,467,147**	$7,578,120	$2,868,278	$9,784,151	$157,213	$58,010	$21,375
	OM&A Expenses	**$4,369,476**	$2,869,490	$502,720	$795,592	$134,238	$29,281	$38,154
	Directly Allocated Expenses	**$0**	$0	$0	$0	$0	$0	$0
	Subtotal	***$24,836,623***	***$10,447,610***	***$3,370,997***	***$10,579,743***	***$291,452***	***$87,291***	***$59,530***
	Working Capital	**$3,725,493**	**$1,567,142**	**$505,650**	**$1,586,961**	**$43,718**	**$13,094**	**$8,929**
	Total Rate Base	**$30,157,946**	**$17,085,222**	**$3,412,086**	**$8,035,050**	**$1,257,666**	**$277,331**	**$90,591**
		Rate Base Input equals Output						
	Equity Component of Rate Base	**$15,078,973**	**$8,542,611**	**$1,706,043**	**$4,017,525**	**$628,833**	**$138,666**	**$45,295**
	Net Income on Allocated Assets	**$1,443,632**	**($73,768)**	**$440,812**	**$1,311,460**	**($188,495)**	**($28,511)**	**($17,866)**
	Net Income on Direct Allocation Assets	**$19,628**	**$15,391**	**$2,581**	**$1,044**	**$10**	**$4**	**$599**
	Net Income	**$1,463,261**	**($58,377)**	**$443,393**	**$1,312,504**	**($188,485)**	**($28,507)**	**($17,267)**
	RATIOS ANALYSIS							
	REVENUE TO EXPENSES %	**101.27%**	83.60%	131.28%	154.06%	19.53%	38.07%	56.52%
	EXISTING REVENUE MINUS ALLOCATED COSTS	**$106,153**	($853,642)	$294,296	$980,078	($251,177)	($42,152)	($21,252)
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.70%	-0.68%	25.99%	32.67%	-29.97%	-20.56%	-38.12%

INTERROGATORY # 21

Ref: Exhibit 9/Tab 1/Schedule 1 (including Appendix A)

a) With respect to page 10-11, please provide a schedule that sets out the allocation of revenues by customer class based on:
   i. The 2006 approved EDR (i.e., as discussed in the application)
   ii. The 2009 billing determinants at 2008 rates (Note: The rates used should exclude any smart meter rate adder. However, the rates and revenues should capture the reduction due to the transformer ownership allowance)

b) With respect to page 14, please confirm that the 50.13% represents the residential share of revenue based on 2008 rates/2009 billing determinants. If not, how was it determined?

c) With respect to page 17, please explain why the bill impact (9.3%) for USL is significantly higher under the proposed rates than for the class allocation consistent with the 2006 approved EDR, when the revenue to cost ratio is actually slightly less.

RESPONSE:

a)

Canadian Niagara Power - Fort Erie
Response to VECC - Fort Erie - 21

		2009 Volumes		2006 EDR Based Rates		2009 Revenue		
Customer Class	No. of Customers / Connections	kWh	kW	Monthly Service Charge	Volumetric Charge	Monthly Service Charge	Volumetric Charge	Total Class Distribution Revenue
Residential	14,255	114,834,621		21.67	0.0081	3,706,740	930,160	4,636,901
General Service Less Than 50 kW	1,181	37,635,552		19.18	0.0286	271,704	1,076,377	1,348,081
General Service 50 to 4,999 kW	146	146,222,353	395,124	125.26	7.6134	218,704	3,008,238	3,226,942
Unmetered Scattered Load	118	345,359		8.87	0.0228	12,507	7,874	20,381
Sentinel Lighting	961	797,374	2,423	2.02	2.2370	23,295	5,420	28,715
Street Lighting	3,088	2,205,484	6,702	1.46	1.7566	54,093	11,772	65,865
	19,747	302,040,745	404,249			4,287,042	5,039,841	9,326,883

Smart Meter Adders have been backed out of the Monthly Service Charge.
Difference total class revenue and the revenue requirement with transformer add back is due to rounding.

b) 50.13% is the residential allocation of the Board Approved 2006 EDR. See Exhibit 9 Tab 1 Schedule 1 Appendix A page 758 of the Application. The values are shown in the third column.

c) As footnoted on the table shown on page 17, the Revenue to Cost Ratio that is shown for the “Class Allocation Consistent with 2006 Approved EDR Rates” is the Revenue to Cost Ratio determined in the CNPI – Fort Erie Cost Allocation Informational Filing.

The Revenue to Cost Ratio associated with the rates determined consistent with the Board Approved 2006 EDR is actually 47.45%. The amount allocated was $20,489 as shown Exhibit 9 Tab 1 Schedule 1 Appendix A on page 771.

INTERROGATORY # 22

Ref: Exhibit 9/Tab 1/Schedule 1, Appendix A

a) Based on a recent 12 consecutive months of actual billing data, please indicate the percentage of total residential customers that:
   - Consume less than 100 kWh per month
   - Consume 100 -> 250 kWh per month
   - Consume 250 -> 500 kWh per month
   - Consume 500 -> 750 kWh per month
   - Consume 750 -> 1000 kWh per month

RESPONSE:

Distribution of Residential Customers based on Monthly Consumption	
Consume less than 100 kWh per month	4.48%
Consume 100 -> 250 kWh per month	9.03%
Consume 250 -> 500 kWh per month	24.83%
Consume 500 -> 750 kWh per month	24.3%
Consume 750 -> 1000 kWh per month	17.06%
Consume > 1000 kWh per month	20.3%

INTERROGATORY # 23

Ref: Harmonized Cost Allocation Model Run

a) Please confirm whether for purposes of the Model Run:
- The Revenues are based on distribution rates (excluding the discounts for transformer ownership allowance)
- The Costs include the cost of the Transformer Ownership Allowance
- The cost of the Transformer Ownership Allowance is allocated to all customer classes

b) Please confirm that in the Current Applications the cost of the Transformer Ownership Allowance is allocated to just the GS>50 class.

c) Please provide the results of an alternative Harmonized cost allocation run (based on the informational filing data) which is consistent with CNP's proposed treatment of the Transformer Ownership Allowance where:
- The Revenues by class are based the rates reduced by the transformer ownership allowance where applicable
- The Costs allocated exclude the "cost" of the Transformer Ownership Allowance.

(Note: For purposes of the response please just file the revise Output Sheet O1)

RESPONSE:

a) CNPI confirms that the revenues are based on distribution rates that include the allowance for transformer ownership allowance, the costs include the transformer ownership allowance and that the transformer ownership allowance is allocated to all classes.

b) CNPI confirms that in the Applications the cost of the transformer ownership allowance is allocated to just the GS>50 class.

c) To proxy the request in this interrogatory, CNPI has removed the transformer allowance costs from Tab I3 Cell F15 of the CNPI-FE_HarmonizedCostAllocationFiling_20080815.xls. Sheet O1 showing the impact of this modification is shown below.

2006 Cost Allocation Information Filing
Canadian Niagara Power Inc - Fort Erie & EOP

Monday, July 14, 2008
Sheet O1 Revenue to Cost Summary Worksheet - Second Run

			1	2	3	7	8	9
Rate Base Assets		**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
crev	Distribution Revenue (sale)	**$9,810,770**	$4,795,124	$1,533,243	$3,366,004	$70,045	$26,508	$19,846
mi	Miscellaneous Revenue (mi)	**$517,904**	$381,047	$75,246	$48,355	$785	$314	$12,157
	Total Revenue	**$10,328,674**	**$5,176,171**	**$1,608,488**	**$3,414,359**	**$70,830**	**$26,822**	**$32,003**
	Expenses							
di	Distribution Costs (di)	**$1,813,533**	$1,053,070	$201,553	$450,785	$86,879	$17,056	$4,189
cu	Customer Related Costs (cu)	**$1,401,008**	$1,069,609	$189,261	$117,387	$2,016	$552	$22,182
ad	General and Administration (ad)	**$2,387,875**	$1,563,095	$288,674	$434,904	$68,994	$13,656	$18,553
dep	Depreciation and Amortization (dep)	**$1,684,651**	$972,184	$183,806	$442,898	$68,931	$13,547	$3,285
INPUT	PILs (INPUT)	**$163,414**	$94,885	$18,365	$41,028	$7,335	$1,443	$357
INT	Interest	**$1,177,975**	$683,984	$132,385	$295,753	$52,877	$10,402	$2,575
	Total Expenses	**$8,628,456**	**$5,436,828**	**$1,014,045**	**$1,782,755**	**$287,032**	**$56,655**	**$51,141**
	Direct Allocation	**$51,795**	**$39,948**	**$7,665**	**$2,821**	**$59**	**$24**	**$1,278**
NI	Allocated Net Income (NI)	**$1,494,893**	$868,000	$168,001	$375,322	$67,102	$13,200	$3,268
	Revenue Requirement (includes NI)	**$10,175,144**	$6,344,775	$1,189,712	$2,160,898	$354,194	$69,879	$55,686
		Revenue Requirement Input equals Output						
	Rate Base Calculation							
	Net Assets							
dp	Distribution Plant - Gross	**$41,748,286**	$24,123,751	$4,629,707	$10,794,872	$1,766,983	$347,598	$85,376
gp	General Plant - Gross	**$5,415,496**	$3,144,576	$605,633	$1,362,907	$242,821	$47,758	$11,800
accum dep	Accumulated Depreciation	**($16,720,272)**	($9,590,920)	($1,830,739)	($4,496,120)	($644,772)	($126,882)	($30,839)
co	Capital Contribution	**($2,197,180)**	($1,276,304)	($231,620)	($568,304)	($97,249)	($19,089)	($4,613)
	Total Net Plant	**$28,246,330**	**$16,401,103**	**$3,172,981**	**$7,093,354**	**$1,267,783**	**$249,385**	**$61,724**
	Directly Allocated Net Fixed Assets	**$748,722**	**$577,458**	**$110,806**	**$40,780**	**$860**	**$348**	**$18,470**
COP	Cost of Power (COP)	**$26,499,812**	$9,609,412	$3,866,981	$12,768,776	$167,808	$59,804	$27,032
	OM&A Expenses	**$5,602,416**	$3,685,775	$679,488	$1,003,076	$157,889	$31,264	$44,924
	Directly Allocated Expenses	**$0**	$0	$0	$0	$0	$0	$0
	Subtotal	***$32,102,228***	***$13,295,186***	***$4,546,469***	***$13,771,853***	***$325,697***	***$91,068***	***$71,955***
	Working Capital	**$4,815,334**	**$1,994,278**	**$681,970**	**$2,065,778**	**$48,855**	**$13,660**	**$10,793**
	Total Rate Base	**$33,810,386**	**$18,972,839**	**$3,965,757**	**$9,199,913**	**$1,317,497**	**$263,394**	**$90,987**
		Rate Base Input equals Output						
	Equity Component of Rate Base	**$16,905,193**	**$9,486,419**	**$1,982,879**	**$4,599,956**	**$658,748**	**$131,697**	**$45,493**
	Net Income on Allocated Assets	**$1,648,423**	**($300,604)**	**$586,778**	**$1,628,782**	**($216,261)**	**($29,857)**	**($20,415)**
	Net Income on Direct Allocation Assets	**$27,299**	**$21,055**	**$4,040**	**$1,487**	**$31**	**$13**	**$673**
	Net Income	**$1,675,722**	**($279,549)**	**$590,818**	**$1,630,269**	**($216,230)**	**($29,845)**	**($19,742)**
	RATIOS ANALYSIS							
	REVENUE TO EXPENSES %	**101.51%**	81.58%	135.20%	158.01%	20.00%	38.38%	57.47%
	EXISTING REVENUE MINUS ALLOCATED COSTS	**$153,530**	($1,168,604)	$418,777	$1,253,461	($283,364)	($43,057)	($23,683)
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.91%	-2.95%	29.80%	35.44%	-32.82%	-22.66%	-43.40%

INTERROGATORY # 24

Ref: Harmonized Cost Allocation Model Run
Harmonized Rate Design Model

a) Please provide a schedule that sets out the Revenue to Cost Ratios by customer class (using the Harmonized Cost Allocation results and Rates) based on:
- The Harmonized 2006 EDR Cost Allocation, and
- The proposed 2009 Harmonized Rates.

In the latter case, please show how the ratios were derived.

b) Please discuss the principles and factors considered in establishing the proposed revenue to cost ratios associated with the 2009 harmonized rate proposal.

c) The CNP-EO Application expressed concerns about the allocation of Miscellaneous Revenues as done in the Cost Allocation Informational filing and makes an adjustment before deriving the non-harmonized CNP-EO rates. Was a similar adjustment made to the miscellaneous revenues in the Harmonized Cost Allocation Model run? If not, why not?

RESPONSE:

a) The following table sets out the revenue-to-cost ratios by customer class:

Revenue to Cost Ratio Summary		
Customer Class	Harmonized 2006 EDR Cost Allocation	Proposed 2009 Harmonized Rates
Residential	80.52%	82.88%
GS < 50 kW	133.51%	120.00%
GS > 50 kW	154.80%	152.66%
USL	57.76%	44.69%
Street Lights	19.51%	23.91%
Sentinel Lights	37.46%	54.61%

The revenue-to-cost ratios were determined in the rate design model, CNPI-Harmonized_DxDesign_20080815.xls, provided with the Application, on Tab [Cost Alloc Revenue Distribution], column K. Where, the proposed revenue-to-cost ratio is equal to the proposed distribution of revenue to a class, column I, divided by the revenue distribution to a class at 100% revenue to cost ratio, column E.

b) There were three main principal factors in establishing the proposed revenue to cost ratios determined in the rate design:

   a. Respecting the Board's guidelines related to the range of revenue to cost ratios for a particular rate class.
   b. Respecting the notion of a total bill impact not exceeding the 10% threshold.
   c. Fairness to customers; this is a balancing act which spreads the overall change in the base revenue requirement to all customer classes respectively.

c) No, a similar adjustment was not done for the Harmonized Cost Allocation Model run. The rationale at the time was not to alter the information used in the original Cost Allocation Informational Filings.

In the case of the CNPI – Eastern Ontario Power rate design, the adjustment to the miscellaneous revenue was made at the rate design phase.

If so directed, CNPI can modify the harmonized cost allocation filing to reflect the adjustment to miscellaneous revenue made in the CNPI – Eastern Ontario Power rate design.

INTERROGATORY # 25

Ref: Harmonized Cost Allocation Model Run
Harmonized Rate Design Model

a) Please confirm that the Harmonized Rate Model uses the revenue requirement distribution from the 2006 EDR based Cost Allocation to establish the 100% revenue to cost ratio allocation (per the Cost Allocation Review and Cost Allocation Revenue Distribution Tabs).
b) Please complete the following table based on the aggregated CNP-FE and CNP-EO customer base:
   - kWh by Customer Class (delivered)
   - Customer/Connection Count
c) Based on the results from part (b), please comment on the appropriateness of assuming that the revenue requirement proportions from the Harmonized 2006 Cost Allocation study can be used for setting 2009 rates.
d) Please provide a schedule that shows the total revenue by customer class, for CNP-FE and CNP-EO, based on 2009 billing determinants and 2008 rates. (Note: The rates used should exclude any smart meter rate adder and any LV charge. The rates and revenues should also capture the reduction due to the transformer ownership allowance.)
e) Please explain why the LV Charges applicable to the CNP-EO service area were not folded into the harmonized rates.
f) Please explain why the Retail Transmission Rates were not harmonized for the two service areas.

RESPONSE:

a) Yes, this statement is correct. The allocations calculated in column C, Revenue Requirement Allocation Percentage, calculates the distribution of revenue, by percentage, using the data from the Harmonized Cost Allocation Informational Filing. This becomes the basis for establishing the 100% Revenue to Cost Ratio allocation in accordance with the Cost Allocation Review and Cost Allocation Revenue Distribution Tabs.

b)

Customer Class (all)	Cost Allocation Filing		2009 Application	
	kWh	% of Total	kWh	% of Total
Residential	141,540,950	36.3%	144,908,265	39.5%
GS < 50	56,958,341	14.6%	51,795,147	14.1%
GS > 50	188,076,527	48.2%	166,344,327	45.3%
Street Light	2,471,714	0.6%	2,766,461	0.8%
Sentinel	880,875	0.2%	877,992	0.2%
USL	398,162	0.1%	444,370	0.1%
Total	390,326,569	100.0%	367,136,562	100.0%

Customer Class (all)	Cost Allocation Filing		2009 Application	
	Number	% of Total	Number	% of Total
Residential	16,789	72.6%	17,434	72.4%
GS < 50	1,539	6.7%	1,601	6.6%
GS > 50	167	0.7%	182	0.8%
Street Light	3,586	15.5%	3,694	15.3%
Sentinel	920	4.0%	1,052	4.4%
USL	116	0.5%	127	0.5%
Total	23,117	100.0%	24,090	100.0%

c) It is CNPI – Fort Erie’s position that the proportions of both throughput and customer counts have not change significantly and the 2006 Cost Allocation study can be used for setting 2009 rates.

The kWh throughput for the General Service 50 to 4,999 kW has decreased, primarily as a result of the loss of load in Gananoque; however, the assumptions are still appropriate in the Application given the Board’s guidance with respect to the allowable ranges of Cost to Revenue Ratios on a per class basis.

d)

Fort Erie

Customer Class	No. of Customers / Connections	kWh	kW	2008 Rates Monthly Service Charge	2008 Rates Volumetric Charge	Monthly Service Charge	Volumetric Charge	Total Class Distribution Revenue
Residential	14,255	115,322,011		19.79	0.0072	3,385,159	830,318	4,215,477
General Service Less Than 50 kW	1,181	37,747,136		17.29	0.0222	244,930	837,986	1,082,917
General Service 50 to 4,999 kW	146	147,729,800	399,198	116.25	7.2398	202,973	2,890,114	3,093,086
Unmetered Scattered Load	20	349,768		8.56	0.0222	2,054	7,765	9,819
Sentinel Lighting	961	797,374	2,423	1.97	1.9700	22,718	4,773	27,491
Street Lighting	3,088	2,210,842	6,718	1.31	1.5823	48,536	10,630	59,165
	19,747	304,156,931	408,339			3,906,369	4,581,586	8,487,956

Gananoque

Customer Class	No. of Customers / Connections	kWh	kW	2008 Rates Monthly Service Charge	2008 Rates Volumetric Charge	Monthly Service Charge	Volumetric Charge	Total Class Distribution Revenue
Residential	3,114	29,586,254		16.06	0.0073	600,130	215,980	816,110
General Service Less Than 50 kW	415	14,048,011		32.61	0.0154	162,398	216,339	378,737
General Service 50 to 4,999 kW	35	18,614,527	58,180	764.70	3.5235	316,586	204,997	521,583
General Service 50 to 4,999 kW TOU				3,292.47	1.1983	-		-
Unmetered Scattered Load	8	94,602		32.87	0.0154	3,156	1,457	4,612
Sentinel Lighting	90	80,618	241	1.78	2.6201	1,922	631	2,554
Street Lighting	597	555,619	1,662	1.77	2.4164	12,670	4,016	16,686
	4,258	62,979,631	60,083			1,096,861	643,421	1,740,282

Note that there are no 2009 volumes associated with GS 50 to 4,999 kW TOU in Gananoque for 2009.

e) The LV charges are unique to the Gananoque services territory. From a cost causality perspective, these charges are more appropriately allocated on a location specific basis.

f) These charges are unique to each operating territory; Fort Erie and Gananoque. The rationale for this decision is that the cost drivers for these charges are unique to the geographic area not the operating and administration regime. In Fort Erie, the distribution system is connected directly to the IESO – controlled grid and attracts the provincial uniform transmission tariffs. In Gananoque, the distribution system is embedded in Hydro One Network Inc.'s distribution system and is not a wholesale market participant and thus attracts costs different than Fort Erie. From a cost causality perspective, these charges are more appropriately allocated on a location specific basis.

INTERROGATORY # 1

Ref: i) Exhibit 1/Tab 1/Schedule 6, page 3, lines 4-9
ii) Exhibit 1/Tab 2/Schedule 1, page 4, lines 25-31
iii) http://www.oeb.gov.on.ca/OEB/_Documents/EB-2006 0268/Comparison_of_Distributors_with_2007_data.xls

a) With respect to the third reference (i.e., the OEB's comparative data for 2005-2007), please provide a schedule that sets out:

- CNP-PC's Total OM&A costs for 2005-2007 per the OEB table
- CNP-PC's annual lease payments to Port Colborne Hydro Inc. for 2005-2007
- CNP-PC's net OM&A costs (i.e., excluding the lease costs) for 2005-2007
- CNP-PC's net OM&A costs per customer for 2005-2007

RESPONSE:

a)

- OM&A Costs Port Colborne	2005	2006	2007
Operations and Maintenance	$ 693,626	$ 800,351	$ 967,698
Administration	3,325,290	3,313,168	3,455,964
Bad Debt Expense	31,898	19,764	66,402
Total OM&A per OEB Tables	$ 4,050,814	$ 4,133,283	$ 4,490,064
Operations and Maintenance	$ 695,618	$ 800,351	$ 967,698
Administration	3,325,291	3,001,116	3,119,564
Bad Debt Expense	31,898	19,764	66,402
Total OM&A per Rate Application(2006 &2007)	$ 4,052,807	$ 3,821,231	$ 4,153,664
Difference	$ (1,993)	$ 312,052	$ 336,400
Reconciling Items			
Other Operating Costs	1,993	-	
Removal of asset charges		(274,520)	(297,756)
Removal of non-recoverable STIs		(18,379)	(17,753)
Reallocation of capital taxes		(19,153)	(20,891)
Difference	$ -	$ -	$ -

The OM&A costs for 2005 were not included in the rate application, therefore there was no need to adjust the numbers.

	2005	2006	2007
- Annual lease payments (includes commodity taxes)	$ 1,533,051	$ 1,533,051	$ 1,533,051
- Total OM&A costs exlcluding lease payments	$ 2,519,756	$ 2,288,180	$ 2,620,613
- Customers per OEB Table	9,135	9,143	9,159
OM&A costs per customer including lease payments	$ 443.66	$ 417.94	$ 453.51
OM&A costs per customer excluding lease payments	$ 275.84	$ 250.27	$ 286.12

INTERROGATORY # 2

Ref: i) Exhibit 1/Tab 1/Scheduele 12
ii) Exhibit 3/Tab 2/Schedule 1, page 15

a) Please re-confirm that CNP-PC is not an embedded distributor and is not billed for "distribution or LV service" by any other distributor? If this is not the case, please clarify.
b) Please describe more fully why Hydro One Networks' deregistration of the IESO delivery point in Port Colborne results in Hydro One Networks' becoming a customer of CNP-PC for distribution service (per the second reference).
c) Has CNP-PC been billing Hydro One Networks as a GS>50 kW customer since December 2006?
d) Are the Hydro One Networks loads included in the Volume and Revenues reported in Exhibit 3/Tab 1/Schedule 2 for 2006-2009? If not, where are these revenues reported in Exhibit 3?
e) Are the Hydro One Networks revenues included in the Distribution Revenue reported in Exhibit 1/Tab 2/Exhibit 4, page 1?

RESPONSE:

a) CNPI – Port Colborne is not an "embedded distributor" as defined in the Distribution System Code. The Distribution System Code defines an "embedded distributor" as a distributor who is not a wholesale market participant and that is provided electricity by a host distributor. CNPI – Port Colborne is a wholesale market participant and all its electricity is provided by the IESO and settled with the IESO.

However, one of CNPI – Port Colborne's wholesale market delivery points, is embedded in a Hydro One Networks' distribution feeder, 41M13, and the demarcation point is known as Dog Junction. At this wholesale market delivery point ownership of the distribution facilities changes from Hydro One Networks to CNPI – Port Colborne. At this wholesale market delivery point, Hydro One settles a Shared Low Voltage Charge, Transmission Connection Charge and Transmission Network Charge with CNPI – Port Colborne. Electricity commodity and commodity associated market charges are settled with the IESO.

In summary, CNPI – Port Colborne is not, by definition, an embedded distributor but does attract shared low voltage line charges from Hydro One Networks for an embedded wholesale market participant delivery point.

b) When the electricity market opened in May 2002, Hydro One Networks had a wholesale market delivery point, Cement Plant Road, embedded in CNPI – Port Colborne's electricity distribution system that provided electricity to Hydro One Networks' distribution customers in the Wainfleet area. Hydro One Networks settled all transmission and commodity related charges directly with the IESO. CNPI – Port Colborne did not have a Board approved shared low voltage line charge.

In November 2006, Hydro One Networks de-registered this wholesale market participant delivery point and the metering point became a retail metering point. This meant that all commodity and transmission charges that were previously assigned by the IESO to Hydro One Networks were now the responsibility of CNPI – Port Colborne and all charges associated with the Cement Plant Road metering point were now added to the CNPI – Port Colborne IESO monthly invoice. CNPI – Port Colborne is now responsible for paying the IESO and billing Hydro One Networks for commodity, delivery and regulatory charges and assumes any risk associated with these charges. Hence, Hydro One Networks became CNPI – Port Colborne's customer, an embedded distributor.

c) Yes, following discussions between Hydro One Networks and CNPI – Port Colborne, CNPI – Port Colborne began billing Hydro One Networks as a General Service 50 to 4,999 kW customer in December 2006.

d) Yes, the Hydro One Network retail metering point is treated as all other retail customer metering points and the loads are included in the Volume and Revenues reported in Exhibit 3/Tab 1/Schedule 2 for 2006-2009.

e) Yes, the Hydro One Network revenues are included in the Distribution Revenue reported in Exhibit 1/Tab 2/Exhibit 4, page 1.

INTERROGATORY # 3

Ref: Exhibit 1/Tab 1/Schedule 14, page 2, line 1

a) Where exactly in the Application is the referenced "reorganization" discussed?

RESPONSE:

The internal reorganization is discussed in the paragraph commencing at line 25 in Exhibit 1, Tab 1, Schedule 14. It involved the transfer of FortisOntario Generation Corporation, previously a wholly-owned subsidiary of FortisOntario and a licensed generator, from FortisOntario to Fortis Properties Corporation, also a wholly-owned subsidiary of Fortis.

INTERROGATORY # 4

Ref: Exhibit 1/Tab 1/Schedule 16, page 1

a) Where in the current Application is the Board's Order regarding updating of depreciation expense and net fixed assets for assets damaged during the 2006 storm specifically addressed?

RESPONSE:

The assets damaged in the Port Colborne service territory from the October 2006 Natural Disaster were owned by Port Colborne Hydro Inc. not by CNPI – Port Colborne. Consequently there is no impact on the rate base with respect to damaged assets that are no longer used and useful.

INTERROGATORY # 5

Ref: Exhibit 1/Tab 2/Schedule 1

a) Are the five 27.6 kV feeders from the Hydro One Networks TS all owned by Port Colborne Hydro and part of the CNP-PC lease (pages 7-8)? If not, please explain.
b) Please clarify the reference to "Low voltage cost to Hydro One" (page 10).
Is the 2009 amount of $20,784 payable to or receivable from Hydro One Networks?
 - If "payable to", please reconcile with Exhibit 1/Tab 1/Schedule 12 where CNP-PC stated that it was not an embedded utility.
 - If "receivable from", does the offset reduce the reported OM&A in the schedule?
 - If the latter, why are the "costs" added in when calculating the Base Revenue Requirement in Exhibit 1/Tab 2/Schedule 4, page 1.

c) With respect to page 10, please provide a schedule that shows the calculation (i.e., volumes and rates) of the "Low Voltage Costs to Hydro One" for 2008 and 2009.
d) What are CNP-PC's current plans regarding obtaining authorization to conduct smart metering activities and subsequently install smart meters on 2009 (page 14 and Exhibit 2/Tab 1/Schedule 1/Appendix A, page 4,lines 7-8)?

RESPONSE:

a) The four 27.6 kV feeders from the Hydro One Networks Port Colborne TS are owned by Port Colborne Hydro and are part of the CNPI – Port Colborne lease. The fifth 27.6 kV feeder emanates from the Hydro One Networks Crowland TS and ownership is demarcated at the Dog Junction wholesale market participant delivery point described in Question #2. The portion of this feeder that is downstream from the demarcation point and within the boundary of Port Colborne is owned by Port Colborne Hydro and is part of the CNPI – Port Colborne lease.

b) The reference to "Low voltage cost to Hydro One" relates to the Hydro One Networks shared low voltage line charges associated with the embedded wholesale market participant delivery point on the 41M13 line and referenced as Dog Junction. These are payable to Hydro One Networks.

As discussed more fully in Question #2, part a, CNPI – Port Colborne is, by definition, not an embedded distributor.

c) The low voltage costs for CNPI – Port Colborne are difficult to forecast with any certainty. Under normal circuit configuration, the 41M13 connection which attracts the shared low voltage line charge of $0.633 per kW normally services a single customer. This customer has approximately 5,000 kW of load displacement generation available.

The load characteristics of this customer will ultimately determine the shared low voltage line charges that will be applied by Hydro One Networks. Should the customer's production levels fall as a result of economic pressures and as a result the embedded generation is sufficient to meet their requirements, there will be little or no shared low voltage line charges. Conversely, if the customer's generators fail to meet the electricity requirements, than the low voltage line charges will likely exceed the forecasted amount.

Further, under emergency conditions, CNPI – Port Colborne may transfer load from adjacent feeders to the 41M13 to restore service. Such an event has the potential to utilize as much as 50% of the forecast in a single month.

CNPI – Port Colborne has based the forecast on historic trends and judgment. For 2008, the estimate was 32,650 kW or $20,665 at $0.633/kW. This amount was slightly inflated to $20,784 in 2009.

d) With its affiliates CNPI-FE and CNPI-EOP, CNPI-PC is part of the Niagara Erie Power Association (NEPA), a consortium comprising nine utilities in the Niagara Region that is pursuing a collective approach to Smart Meter/Automated Meter Infrastructure (AMI) implementation. NEPA engaged the services of Util-Assist, Inc. to facilitate the process, a service that Util-Assist is also providing to other utility consortiums in Ontario working towards Smart Meter/AMI implementation.

NEPA has prepared technical and economic models for evaluating Smart Meter/AMI suppliers and installers and temporary Operational Data Storage (ODS) providers. Pursuant to O. Reg. 427/06, NEPA "piggybacked" on the London Hydro RFP process for selecting a Smart Meter/AMI supplier. The evaluation process was facilitated by London Hydro and overseen by a Fairness Commissioner authorized by the Ministry of Energy. As a result of this process, Sensus Technologies was selected as the Smart Meter/AMI supplier for the NEPA consortium. Progress to date on Smart Meter/AMI implementation can be summarized as follows:

- Sensus selected as Smart Meter/AMI supplier. Contract expected to be signed by December 31, 2008.
- Proposals for Installation services are currently being evaluated and a decision will be made after such evaluation.
- RFP issued for temporary ODS services.

By "piggybacking" on the London Hydro RFP process in accordance with the provisions of O. Reg. 427/06, the NEPA consortium and CNPI-PC is authorized by the Ministry of Energy to deploy Smart Meter/AMI. CNPI-PC expects to commence deployment in July 2009.

INTERROGATORY # 6

Ref: Exhibit 1/Tab 2/Schedule 4

a) Please provide a schedule that sets out the calculation of 2009 distribution revenues (by customer class) based on existing rates. The schedule should show the fixed and variable rates plus the associated billing quantities used for each customer class.
b) With respect to the schedule prepared in response to part (a), please clarify whether the loads used to determine the revenues for GS>50 include Hydro One Networks' loads.
c) Why are there no "Low Voltage Wheeling Costs" reported for 2006 and 2007?

RESPONSE:

a)

Canadian Niagara Power - Port Colborne

		2009 Volumes		2008 Rates		2009 Revenue		
Customer Class	No. of Customers / Connections	kWh	kW	Monthly Service Charge	Volumetric Charge	Monthly Service Charge	Volumetric Charge	Total Class Distribution Revenue
Residential	8,144	64,972,406		15.59	0.0154	1,523,486	1,000,575	2,524,061
General Service Less Than 50 kW	933	25,831,151		31.05	0.0090	347,636	232,480	580,116
General Service 50 to 4,999 kW	81	99,392,250	377,959	620.00	2.3984	598,920	906,496	1,505,416
Unmetered Scattered Load	19	581,173		31.32	0.0093	7,141	5,405	12,546
Sentinel Lighting	37	12,725	38	2.10	6.1316	932	233	1,165
Street Lighting	1,988	1,792,552	5,433	1.39	2.7636	33,160	15,014	48,174
	11,201	192,582,257	383,429			2,511,275	2,160,203	4,671,478

b) Yes, the loads used to determine the revenues for GS>50 include Hydro One Networks' loads.

c) For 2006 and 2007, the "Low Voltage Wheeling Costs" were improperly recorded as distribution revenue. Adjusting entries were made in 2008.

INTERROGATORY # 7

Ref: Exhibit 2/Tab 2/Schedule 1

a) Please explain the "allocations" shown under Gross Fixed Assets and Accumulated Depreciation for each of the years.

- For each account, was the same allocation percentage used across all four years?
- Was the same allocation methodology applied to each account for all four years?
- The BDR report does not set out the allocation by account. Please describe the allocation factor currently used for each account.

b) Please explain the large increase in the allocation for Account #1960 as between 2006 ($2,160) and 2009 ($130,563).

c) Please confirm that the assets set out in this schedule only include the asset additions by CPN-PC since the execution of the lease with Port Colborne Hydro Inc.

d) There is a fairly large increase in the allocation of transport equipment (Account 1930) from 2006 to 2009. Please provide an explanation of the aggregate expenditures made each year by CNPI on Transport Equipment.

RESPONSE:

a) The same allocation percentage was used across all four years.

The same allocation methodology was applied to each account for all four years.

The allocation factor used for computer equipment and software follows the Information Technology department allocations shown in the BDR report Exhibit 4/Tab 2/Schedule 4/Appendix B page 12, i.e., CNPI - Fort Erie 29%, CNPI - Port Colborne 17% and CNPI - Gananoque 8%.

The allocation factor for transportation equipment allocations follows the T&D Operations allocations shown in the BDR report Exhibit 4/Tab 2/Schedule 4/Appendix B page 12, i.e., CNPI - Fort Erie 55%, CNPI - Port Colborne 32% and CNPI – Gananoque 0%.

The above allocation factors are based on FTEs. Please refer to the BDR report Exhibit 4/Tab 2/Schedule 4/Appendix B page 6, for a more detailed explanation of the allocation of FTEs.

Computer software costs were allocated after the land management system was fully allocated to CNPI - Fort Erie.

The allocation factor for the Service Centre Rent and maintenance is CNPI-Fort Erie 46%, CNPI - Port Colborne 20% and CNPI - Gananoque 6%. This allocation is based on the FTEs occupying the Fort Erie Service Centre.

b) The large increase in the allocation for Account #1960 between 2006 and 2009 is the result of forecasted expenditures in CNPI of approximately $109,000 in 2008 and $140,000 in 2009. These expenditures are for the creation of a digital database to support implementation of engineering analysis software tools, outage management and mapping systems as discussed in CNPI - Fort Erie's Exhibit 2, Tab 3, Schedule 1, Appendix A, Page 16.

c) The assets set out in this schedule only include the assets additions by CNPI - Port Colborne since the execution of the lease with Port Colborne Hydro Inc.

d) CNPI - Fort Erie Transportation Equipment Expenditures in table below:

Year	Amount	Units
2006	$316,000.00	- four vans - new braking unit - new wrinching unit
2007	$300,000.00	- van - digger derrick - line truck
2008	$354,000.00	- bucket truck - two cargo vans - pickup truck
2009	$365,000.00	- line digger truck - cargo van - passenger cars for customer service and planning departments

INTERROGATORY # 8

Ref: Exhibit 2/Tab 3/Schedule 1, Appendix A

a) With respect to New Service Lines (page 7), please indicate the number of new customers and number of upgrades to existing services associated with the spending in each year.

RESPONSE:

The requested information is presented in the Table below.

Year	**2006**	**2007**	**2008 YTD**
New services	58	48	43
Upgraded services	94	101	83

INTERROGATORY # 9

Ref: Exhibit 2/Tab 3/Schedule 1, Appendix B, page 1 (lines 11-16)

a) The referenced BDR report does not appear to provide the derivation of the percentage allocations for each service territory. Please provide the supporting calculations.

RESPONSE:

The percentage allocations for information technology are in the BDR report; Exhibit 4/Tab 2/Schedule 4/Appendix B page 12.

The percentage allocation for CNPI – Fort Erie includes an editing error. The percentage allocation for CNPI – Fort Erie should be 29% and not 24%. The correct number was used in the allocation calculation.

INTERROGATORY # 10

Ref: Exhibit 2/Tab 4/Schedule 2, page 1

a) With respect to Power Supply Expenses, please provide a schedule that for each expense sets out (for 2008 and 2009):

- The volumes involved
- The assumed rate
- The total costs.

b) Please update the calculation to reflect:

- The approved wholesale transmission rates as of January 1, 2009.
- The forecast cost of power as presented in the Board's RPP Price Report, released October 15, 2008.

RESPONSE:

CNPI - Port Colborne Original Cost of Power Forecast

	2008			2009		
	Volume		Cost	Volume		Cost
Wholesale Market Service Charge	191,277,011	kWh	1,233,494	192,582,257	kWh	1,193,775
Transmission Connection Service Charge	380,070	kW	873,917	383,429	kW	865,016
Transmission Network Service Charge	380,070	kW	979,178	383,429	kW	924,801
Cost of Power	191,277,011	kWh	10,743,331	192,582,257	kWh	10,493,664
LV Charges			35,723			20,783
			13,865,643			13,498,039

CNPI - Port Colborne Updated Cost of Power

	2009		
	Volume		Cost
Wholesale Market Service Charge	192,582,257	kWh	1,193,775
Transmission Connection Service Charge	383,429	kW	911,547
Transmission Network Service Charge	383,429	kW	991,482
Cost of Power	192,582,257	kWh	11,610,421
LV Charges			20,783
			14,728,008

a) The table shown above highlights the cost of power calculation details for 2008 and 2009 complete with volumes. The assumed cost of energy was $0.0545 per kWh per the Board's RPP Price Report dated April 11, 2008.

The wholesale transmission rates were based on the following Board approved charges:

Network Service Rate $2.31/kW

Line and Transformation Service Rate $2.20/kW

b) The table on the previous page also shows the updated 2009 cost of power calculation details complete with volumes. The assumed cost of energy was $0.0603 per kWh per the Board's RPP Price Report dated October 15, 2008.

The wholesale transmission rates were based on the following Board approved charges effective January 1, 2009:

Network Service Rate $2.57/kW

Line and Transformation Service Rate $2.32/kW

CNPI – Port Colborne has also take into account the adjustment to the anticipated in the OEB Board Staff interrogatory # 70, the ongoing variance adjustment calculation.

INTERROGATORY # 11

Ref: Exhibit 3/Tab 1/Schedule 2, page 1

a) Please confirm whether the rates used to determine the 2009 revenues by customer class:
  - Excluded the smart meter rate adder
  - Were reduced to reflect the transformer ownership allowance, where appropriate.

b) Please reconcile the Distribution revenues reported here for 2009 with the Base Revenue Requirement reported at Exhibit 9/Tab 1/Schedule 1, page 6.

c) Please reconcile the Distribution Revenues reported here for 2009 (by customer class) with those reported in the Rate Design Model (Reconciliation of 2009 Rates tab).

RESPONSE:

a) CNPI – Port Colborne confirms that the rates used to determine the 2009 revenues by customer class excluded the smart meter adder and were reduced by the transformer ownership allowance as appropriate.

b) During an attempt to reconcile the distribution revenues reported here for 2009 with the Base Revenue Requirement reported at Exhibit 9/Tab 1/Schedule 1, page 6 an error was found in the Rate Design Model. The genesis of the error is on Tab "DxRates 2006 EDR Distributions" in cells C10 to D15. The volumes in kWh and kW have been calculated as the average of the 2008 Bridge Year and the 2009 Test Year volumes which was in error.

   These cells should contain the 2009 forecasted volumes. Effectively this error has understated the volumes and subsequently overstated the rates.

   This will be corrected in a subsequent rate design model and will factor any other issues arising in the interrogatory phase of the review, for example the recalculation of retail transmission rates.

c) Same as b) above

INTERROGATORY # 12

Ref: Exhibit 3/Tab 2/Schedule 1, pages 2-5

a) Please provide a schedule that sets out:
- the kWh per customer for the Residential, GS<50 and GS>50 customer classes based on the Hydro One Weather Normalized data (per page 2, lines 29-30).
- The kWh per customer class for the Residential, GS<50 and GS>50 customer classes (for the same year) using CNP-PC's weather normalization methodology.

b) The CNP-CP weather normalization methodology is based on the premise that that the mix of weather sensitive and non-weather sensitive loads for CNP-PC is a reasonable subset of the overall IESO controlled grid. For weather sensitive load, the IESO normalization methodology captures the weather impacts across the entire province and, in doing so, reflects not only the weather across the entire province and reflects the amount of weather sensitive load (e.g., space heating and space cooling) in each customer class.
- Why is it reasonable to assume that, for weather sensitive loads, the weather adjustment for CNP-PC would be the same as for the province as a whole? Are the heating and cooling degree days in CNP-PC similar to those for the province as a whole? Is the saturation of space heating and cooling appliances the same in CNP-PC as it is for the province as whole?

c) The table on page 5 only compares 30 years of weather data for CNP-PC with that for the years 2005, 2006 and 2007. Please explain how this comparison supports applying the weather correction factor derived from the IESO provincial data to the CNP-PC data.

d) With respect to the table of page 5, the impact of a heating degree day on electricity load will be different than the impact of a cooling degree day (i.e., each will depend respectively on the extent of installation of electric space heating and cooling equipment).
- Please explain why it is reasonable to compare the sum of the mean heating and cooling days.
- Please confirm that what the table shows is that for the period 2005-2007, the heating degree days were all lower than the 30 year average while the cooling degree days were all higher.

RESPONSE:

a) The table shown below shows the 2004 data from the Cost Allocation Informational Filing, the Hydro One Weather Normalized data from the same filing and the 2004 data normalized using CNPI methodology used in this Application.

Comparison of Weather Normalization Data			
Class	Actual Data (kWh)	Hydro One Normalized Data (kWh)	CNPI Methodology (kWh)
Residential	62,256,160	71,226,561	62,432,550
GS < 50 kW	26,781,130	31,474,224	28,857,009
GS > 50 kW	104,648,698	86,324,987	104,751,318

The IESO correction factor as calculated consistent with the methodology used by CNPI was a 0.28% adjustment upward.

The Hydro One normalized data shows a great deal of volatility between actual sale data and the normalized data. CNPI has not seen this level of volatility in its sales year over year other than events associated with discrete activities such as customer closures.

b) Notwithstanding the discussion of the points raised in the question, CNPI suggests that the IESO weather correction formulation is a reasonable proxy to use in the Application.

For all electricity distribution companies' throughput and demand will be changing constantly in response to a number of external factors including customer additions and deletions, weather conditions, customer behaviour and industrial commercial activity. In smaller utilities, like CNPI, where there is limited diversity in its customer base and response to these factors maybe often skewed in response to singular events. For example the behavior of the embedded generators in CNPI – Port Colborne to gas price signals, industrial closures in Port Colborne and Gananoque and residential customer behavior in response to these externalities. Weather normalization is only one of many variables that have to be considered.

CNPI suggests that the IESO 18 Month Outlook: Ontario Demand Forecast is a reasonable proxy of the electrical system response to a wide range of variables in the economy and is the better choice for normalizing the throughput data of a smaller LDC like CNPI.

c) CNPI – Port Colborne has included this information only to illustrate the correlation between the total mean degree days and the normalizing adjustment factors used to develop the normalized throughput. Comparing the values for 2005 and 2006 shows a reduction in the number of mean degree days likewise the adjustment factor developed in this Application has reduced the throughput.

d) As discussed in part c), this was developed to show that a correlation existed in the trend of total mean degree days and the adjustments being made to throughput. As well, this information supports the notion that none of these years were extreme weather years.

CNPI confirms that the data presented in this table shows that for the period 2005-2007, the heating degree days were all lower than the 30 year average while the cooling degree days were all higher.

INTERROGATORY # 13

Ref: Exhibit 3/Tab 2/Schedule 1, pages 8-9

a) Please describe the nature of the supply arrangements for the 21 residential customers that will be transferred to Hydro One Networks at the end of 2008. Prior to the transfer, please explain:
   - The arrangements between CNP-PC and Hydro One Networks regarding the treatment of revenues from these customers (i.e., what rates were applied to these customers, who billed them, who retained the revenues) and
   - Whether there were any specific cost transfers between CNP-PC and Hydro One associated with these customers. If so, what were the 2007 and 2009 amounts and what were they for?

b) The elimination of the load transfer arrangements leads to a loss of customers (and revenue) for CNP-PC. Does it also result in a reduction in costs incurred (apart from cost of power related charges)? If so, where are these factored into the 2009 rate application?

c) The discussion on page 9 makes reference to "normalized values" for Residential usage. Please describe how the weather normalized values for Residential; GS<50; and GS>50 usage were derived.

RESPONSE:

a) Exhibit 3/Tab 2/Schedule 1, pages 8-9 actually refer to transfer customers with Welland Hydro Electric System Corporation ("Welland Hydro") not Hydro One Networks.

   The 21 residential customers are connected to Welland Hydro's physical distribution assets, therefore Welland Hydro is the physical distributor and the customers are located in CNPI – Port Colborne's geographic territory, therefore CNPI – Port Colborne is the geographic distributor.

   Welland Hydro settles all commodity and commodity related charges for these customers with the IESO. Therefore, Welland Hydro receives from CNPI – Port Colborne the commodity and commodity related revenue. CNPI – Port Colborne services the customers and therefore retains the distribution revenue.

Other than regular billing of delivery and commodity charges there are no other arrangements associated with these customers.

b) The cost reduction caused by the transfer of 21 residential customers would be insignificant and therefore was not factored into forecasted 2009 costs.

c) The matter of “normalized values” has been discussed in the VECC interrogatory # 12.

INTERROGATORY #14

Ref: Exhibit 3/Tab 2/Schedule 1, pages 13-15

a) Please provide a schedule that for each of the years 2005-2007 sets out the number of months that each of the two customers experienced a “billing demand”. (Note: The maximum value for any one year would be 24)

RESPONSE:

a) The two standby customers normally establish a billing demand every month. This is normally established on an off peak period to allow regular maintenance. Therefore the answer is 24 for each year.

INTERROGATORY # 15

Ref: Exhibit 3/Tab 2/Schedule 1, page 21

a) Please confirm that the 2 Standby customers were treated as a separate customer class for purposes of the Cost Allocation Informational filing.

RESPONSE:

CNPI – Port Colborne confirms that the two standby customers were treated as a separate customer class for purposes of the Cost Allocation Informational filing. However, the revenue from distribution rates, both the monthly service charge and the volumetric charge are included with the General Service 50 to 4,999 kW class.

Output sheet O1 from Run #2 is shown on the following page.

2006 Cost Allocation Information Filing
Canadian Niagara Power Inc. - Port Colborne

EB-2005-0345 EB-2007-0001
Thursday, January 18, 2007
Sheet O1 Revenue to Cost Summary Worksheet - Second Run

			1	2	3	7	8	9	11
Rate Base Assets		**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Back-up/Standby Power**
crev	Distribution Revenue (sale)	**$4,455,806**	$2,429,942	$587,789	$1,384,594	$38,548	$1,228	$13,705	$0
mi	Miscellaneous Revenue (mi)	**$452,227**	$292,622	$71,649	$63,771	$6,571	$159	$6,350	$11,105
	Total Revenue	**$4,908,033**	**$2,722,564**	**$659,437**	**$1,448,365**	**$45,119**	**$1,387**	**$20,055**	**$11,105**
	Expenses								
di	Distribution Costs (di)	**$729,989**	$374,618	$100,130	$163,472	$42,016	$716	$1,974	$47,063
cu	Customer Related Costs (cu)	**$714,862**	$526,854	$121,029	$56,336	$1,573	$92	$8,977	$0
ad	General and Administration (ad)	**$2,473,699**	$1,531,553	$377,600	$385,911	$75,113	$1,388	$18,349	$83,784
dep	Depreciation and Amortization (dep)	**$349,221**	$166,520	$48,167	$95,113	$13,407	$228	$746	$25,038
INPUT	PILs (INPUT)	**$33,236**	$15,378	$4,617	$9,394	$1,221	$21	$71	$2,535
INT	Interest	**$239,518**	$110,820	$33,273	$67,702	$8,797	$150	$510	$18,265
	Total Expenses	**$4,540,524**	**$2,725,744**	**$684,816**	**$777,929**	**$142,127**	**$2,595**	**$30,627**	**$176,686**
	Direct Allocation	**$63,466**	**$47,967**	**$10,897**	**$2,996**	**$222**	**$13**	**$1,371**	**$0**
NI	Allocated Net Income (NI)	**$304,043**	$140,675	$42,237	$85,941	$11,166	$190	$647	$23,186
	Revenue Requirement (includes NI)	**$4,908,033**	$2,914,387	$737,951	$866,865	$153,516	$2,798	$32,645	$199,872
		Revenue Requirement Input equals Output							
	Rate Base Calculation								
	Net Assets								
dp	Distribution Plant - Gross	**$3,850,167**	$1,784,948	$534,158	$1,084,428	$142,855	$2,434	$8,240	$293,103
gp	General Plant - Gross	**$1,504,062**	$696,354	$208,809	$424,609	$55,462	$945	$3,208	$114,676
accum dep	Accumulated Depreciation	**($798,524)**	($372,092)	($110,499)	($222,926)	($30,326)	($517)	($1,731)	($60,433)
co	Capital Contribution	**($37,624)**	($18,539)	($4,892)	($9,311)	($1,941)	($33)	($96)	($2,812)
	Total Net Plant	**$4,518,081**	**$2,090,671**	**$627,576**	**$1,276,801**	**$166,050**	**$2,829**	**$9,622**	**$344,533**
	Directly Allocated Net Fixed Assets	**$381,646**	**$288,448**	**$65,529**	**$18,014**	**$1,336**	**$76**	**$8,244**	**$0**
COP	Cost of Power (COP)	**$13,535,922**	$4,325,290	$1,860,638	$7,270,541	$35,725	$343	$43,385	$0
	OM&A Expenses	**$3,918,550**	$2,433,026	$598,759	$605,719	$118,703	$2,196	$29,300	$130,847
	Directly Allocated Expenses	**$0**	$0	$0	$0	$0	$0	$0	$0
	Subtotal	***$17,454,472***	***$6,758,316***	***$2,459,396***	***$7,876,261***	***$154,428***	***$2,539***	***$72,685***	***$130,847***
	Working Capital	**$2,618,171**	**$1,013,747**	**$368,909**	**$1,181,439**	**$23,164**	**$381**	**$10,903**	**$19,627**
	Total Rate Base	**$7,517,897**	**$3,392,866**	**$1,062,014**	**$2,476,253**	**$190,550**	**$3,286**	**$28,768**	**$364,160**
		Rate Base Input equals Output							
	Equity Component of Rate Base	**$3,758,949**	**$1,696,433**	**$531,007**	**$1,238,127**	**$95,275**	**$1,643**	**$14,384**	**$182,080**
	Net Income on Allocated Assets	**$304,043**	**($51,147)**	**($36,276)**	**$667,441**	**($97,230)**	**($1,220)**	**($11,943)**	**($165,581)**
	Net Income on Direct Allocation Assets	**$33,454**	**$25,285**	**$5,744**	**$1,579**	**$117**	**$7**	**$723**	**$0**
	Net Income	**$337,497**	**($25,862)**	**($30,532)**	**$669,020**	**($97,113)**	**($1,214)**	**($11,220)**	**($165,581)**
	RATIOS ANALYSIS								
	REVENUE TO EXPENSES %	**100.00%**	93.42%	89.36%	167.08%	29.39%	49.58%	61.43%	5.56%
	EXISTING REVENUE MINUS ALLOCATED COSTS	**($0)**	($191,822)	($78,513)	$581,500	($108,397)	($1,411)	($12,590)	($188,767)
	RETURN ON EQUITY COMPONENT OF RATE BASE	8.98%	-1.52%	-5.75%	54.03%	-101.93%	-73.87%	-78.00%	-90.94%

INTERROGATORY # 16

Ref: i) Exhibit 3/Tab 3/Schedule 1, page 1
ii) Exhibit 3/Tab 1/Schedule 2
iii) Exhibit 3/Tab 2/Schedule 1, page 13 and Appendix A

a) Please confirm where the following are included in the revenues reported in references (i) and (ii):

- Revenue from the application of standby rates to the two embedded generator customers
- Revenue from the energy and capacity withdrawn (per reference (iii), page 13) to allow for routine maintenance and/or forced outages.

b) What was the total standby revenue in each of 2005, 2006, 2007 and 2008?

RESPONSE:

a) Revenue from the application of standby rates to the two embedded generator customers has been recorded as Miscellaneous Service Revenue, account 4235.

Revenue from the energy and capacity withdrawn (per reference (iii), page 13) to allow for routine maintenance and/or forced outages is recorded as distribution income.

b) Total standby revenue in each of 2005, 2006, 2007 and 2008 is a contracted amount at $122,400 per year.

INTERROGATORY # 17

Ref: i) Exhibit 4/Tab 1/Schedule 1, page 2
ii) Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, July 2008

a) Given that the term of the 3rd Generation IRM is four years (rebasing year plus 3 years (reference (ii), page 7), why is CNP-PC proposing to recover 1/3 of the regulatory costs in the test year?

b) Are each of the following regulatory costs for the 2009 EDR third party (as opposed to internal or shared) costs:
• Legal Review and Regulatory
• External Consultation

c) Where and how is the $19,800 reflect in the 2009 OM&A forecast shown in Reference Exhibit 4/Tab 2/Schedule 2, page 1

RESPONSE:

a) It is CNPI-PC's expectation that it will be required to rebase in three years, i.e., in 2012, when the operating lease expires in April 2012.

b) Legal review and regulatory and external consultation are third party costs.

c) The $19,800 is in account 5655 – Regulatory Expense as an expense.

INTERROGATORY # 18

Ref: i) Exhibit 4/Tab 1/Schedule 1, pages 2-7
ii) Exhibit 4/Tab 2/Schedule 2
iii) Exhibit 4/Tab 2/Schedule 4, page 4

a) With respect to the 2006 (actual) through 2009 forecast OM&A costs shown in reference (ii), please provide a schedule that for each major category of expenses (e.g., Distribution Expense – Operation Total) shows the amount associated with purchased services from affiliates.

RESPONSE:

a) **Purchased Services from Affiliates**

Category	2006 Actual	2007 Actual	2008 Bridge Year	2009 Test Year
Distribution expense-Operations [1]	$ 259,890	$ 314,627	$ 264,731	$ 266,773
Distribution expense-Maintenance [1]	202,204	308,933	326,146	335,897
Billing and Collection [1]	308,326	371,150	364,971	361,330
Total purchased services	$ 770,421	$ 994,710	$ 955,848	$ 964,000
Administrative and General Expenses (Affiliated shared services) [2]	$ 771,996	$ 812,886	$ 898,897	$ 944,123

[1] direct charges through timesheet entry
[2] as per Exhibit 4/Tab2/Schedule 4, page 4, Affiliated Expenses

INTERROGATORY # 19

Ref: i) Exhibit 4/Tab 2/Schedule 1, Appendix B, page 4
ii) Exhibit 4/Tab 2/Schedule 1, Appendix C
iii) Exhibit 4/Tab 2/Schedule 3, Appendix A, page 3

a) What analysis or assessments has CNP-PC carried out to support the need for a three-year vegetation management cycle?
b) Please provide CNP-PC spending on vegetation management for 2006, 2007, and 2008. Is all spending reported in sub-account #5135?
c) Do each of the three geographical zones lead to roughly the same vegetation management expense?
d) Please explain why there is a need to intensify the vegetation management program in 2009 (per reference (iii)) and what this intensification entails.

RESPONSE:

a) CNPI – Port Colborne has determined with experience that a three-year cycle is a reasonable and appropriate period for vegetation management. Port Colborne is a heavily treed area with rapid vegetation growth. The vegetation management program aims to maintain adequate clearance between trees and lines while respecting as much as possible the natural environment. A cycle longer than three years would not provide as effective vegetation control, because trees would encroach on lines before scheduled trimming. A cycle of less than three years would be inefficient.

b) Spending by year is as follows:

2006 Actual	2007 Actual	2008 Forecast
$166,568	$85,062	$85,276

Spending in 2006 was abnormally high because the 2005 vegetation management contract was not completed in 2005, and therefore had to be completed in 2006 along with the scheduled 2006 work.

All vegetation management spending is reported in account #5135.

c) Yes, each zone entails approximately the same vegetation management expense.

d) In 2009, CNPI – Port Colborne has determined that there are particular areas outside the three-year cycle to be optimal, there is a need to address problems that arise in areas outside of the scheduled zone. They include heavily wooded areas that require proactive attention, such as, for example, the fire lanes.

As the program is executed at the proposed level of expenditure, it is believed that the result of the intensification in the 2009 Test Year will address the rate of tree growth and also minimize the problem areas outside the scheduled zone.

INTERROGATORY # 20

Ref: i) Exhibit 4/Tab 2/Schedule 3, Appendix A
ii) Exhibit 4/Tab 2/Schedule 2

a) With respect to Account #5005:
• Please reconcile the $112,735 decrease in Account #5005 discussed in reference (i) – page 2 – with the reported changes in reference (ii).
• Please reconcile the comment that expenditures in 2009 are constant per reference (i) with the 17% increase reported in reference (ii).

b) With respect to Accounts #5125 and 5130:
• Capital spending in 2008 (per Exhibit 2/Tab 1/Schedule 1, page 2) was less in 2008 than in 2007 and 2006. Please reconcile this with the statement in reference (i) – page 3 – that there was a need to reallocate labour to capital projects in 2008.
• In what areas was maintenance decreased in 2008 as a result of labour reallocations to capital projects (per reference (i) – page 3)?
• What are the maintenance activities that are receiving increased focus for 2009 (versus 2008)?
• The increase in 2009 over 2008 is much larger than the decrease in 2008 versus 2007 (per reference (ii)). This suggests that the increase in 2009 is more than just a "correction" of the 2008 re-allocation to capital projects. Please explain what accounts for the 12% increase in spending on these two accounts between 2007 and 2009.

RESPONSE:

(a) With respect to Account #5005:

- The $112,735 discussed in reference (i) pertains to the overall decrease in costs for Distribution Expenses-Operation Total from 2007 Actual to 2008 Bridge Year. It does not refer to Account # 5005. Reference (ii) shows the decrease of $112,735 for Distribution Expenses-Operation Total from 2007 Actual to 2008 Bridge Year, and is consistent with the statement in reference (i).
- The statement that expenditures remain constant for 2009 Test Year refers to overall Distribution Expenses-Operation Total costs. Reference (ii) shows an increase of $9,267 for 2009 Test Year over 2008 Bridge Year for Distribution Expenses-Operation Total. This is a negligible increase of 2.3% and not 17%.

(b) With respect to Accounts #5125 and 5130:

- Costs to these accounts are primarily incurred by work carried out by CNPI Line crews. CNPI Line crews perform maintenance and capital work in both Port Colborne and Fort Erie, and CNPI applies flexibility in allocating resources to address operational needs in the two territories. In 2008, there were two major projects in Fort Erie that required increased capital spending over 2007 – the Voltage Conversion program and the Major Undergrounding Projects. These projects required the allocation of additional labour resources. In addition, capital expenditures are the total cost of internal labour, contractors, and material. As a result of these variable factors, a decrease in expenditures in specific maintenance accounts in Port Colborne would not necessarily translate into an equivalent increase in Port Colborne capital expenditures.
- In 2008, the primary decrease was in switch maintenance activity.
- Switch maintenance will receive increased focus for 2009. CNPI-PC also plans to perform insulator washing, thermographic scanning, and pole testing in 2009.
- Insulator washing, thermographic scanning, and pole testing were not carried out in 2007, hence the anticipated 12% increase in costs from 2007 Actual to 2009 Test Year.

INTERROGATORY # 21

Ref: i) Exhibit 4/Tab 2/Schedule 3, Appendix B
ii) Exhibit 4/Tab 2/Schedule 2

a) Please explain the 22% increase in meter reading expense from 2008 to 2009.

b) Please explain the basis for the $40,000 bad debt expense forecast for 2008 and why the 2009 value increases by more than 50%.

c) Where were the labour costs that are now budgeted to Community Relations previously accounted for (reference (i) – page 2)? Have the forecast costs in this account been decreased accordingly?

RESPONSE:

a) A customer service employee who performed miscellaneous customer meter reads resigned in 2007 and was not replaced. This work was redistributed amongst other customer service employees. Time and costs for meter reading work was not appropriately allocated to the meter reading account in 2008 but was primarily charged to the collecting account. For 2009, the expenses for meter reading have been appropriately allocated to the meter reading account which resulted in a corresponding decrease in the collecting account.

b) The 2008 Bridge Year forecast was based on 2006 actuals as well as the economic climate in the area. The 2009 Test Year forecast for bad debt expense was based on 2007 actuals which were $66,000. In addition, to date 2008 write-offs in Port Colborne are approximately $48,000. In late 2008 and 2009, there are a number of manufacturing plants closing or downsizing in the Niagara Region which will affect household incomes in the area. Furthermore, the number of retailer enrolled accounts has increased significantly over the past few years. A sampling of the largest balances per account written off in the second half of 2008 indicated that 40% of those dollars are associated with accounts enrolled with an electricity retailer. This is a much greater percentage than the total customers enrolled with electricity retailers in Port Colborne, which is currently 17%. Compared to the current RPP pricing, the monthly billing for customers enrolled with an electricity retailer is typically higher that those without and could therefore further affect bad debts. For these reasons CNPI has budgeted $66,000 in bad debts for the 2009 test year.

c) CNPI has a renewed focused on Community Involvement and is therefore allocating more labour related time to this order. Current initiatives include school safety/conservation programs as well as an annual customer satisfaction survey. The labour costs budgeted to Community Relations were previously budgeted elsewhere in CNPI.

INTERROGATORY # 22

Ref: Exhibit 4/Tab 2/Schedule 4, page 4

a) For the years 2006, 2007, 2008 and 2009 please provide:
• The total Corporate services costs of Fortis Ontario that were allocated and the % allocated to CNP-PC
• The total Corporate services costs of Fortis Inc. that were allocated and the % allocated to CNP-PC
• The total Administrative services costs of CNPI-Fort Erie that were allocated and the % allocated to CNP-PC

b) Please indicate which Service Agreements (per Appendix A) address each of the expenses items set out in the Table on page 4.

c) The first Service Agreement in Appendix A suggests that CNPI purchases a range of services from Cornwall Street Railway, Light and Power Company. However, page 4 does not include any services from Cornwall. Please reconcile.

d) The third Service Agreement in Appendix A suggests that CNPI purchases a range of services from FortisOntario Generation. However, page 4 does not include any services from FOGEN. Please reconcile.

RESPONSE:

($'000)

		2006 Board Approved	2006 Actual	2007 Actual	2008 Bridge Year	2009 Test Year
a)	**Corporate services FortisOntario**					
	Corporate services costs	$ 1,776	$ 1,509	$ 1,509	$ 1,510	$ 1,477
	Percentage allocation to CNP-PC	18.0%	12.0%	12.0%	12.0%	12.0%
	Allocation to CNPI-PC	$ 320	$ 181	$ 181	$ 181	$ 177
	Corporate services Fortis Inc.					
	Corporate services costs	$ -	$ 159	$ 137	$ 150	$ 170
	Percentage allocation to CNP-PC	0.0%	20.8%	21.2%	12.7%	12.9%
	Allocation to CNPI-PC	$ -	$ 33	$ 29	$ 19	$ 22
	Administrative Costs CNPI-FE					
	Total CNPI-FE admin. Costs allocated	$ 1,953	$ 2,617	$ 2,540	$ 2,405	$ 2,558
	Percentage allocation to CNP-PC	23.1%	17.3%	19.8%	25.2%	25.4%
	Allocation to CNPI-PC	$ 451	$ 453	$ 503	$ 606	$ 650

b) The following Services Agreements address the expense items set out in the Table on page 4:

Corporate Services provided by FortisOntario	The fourth agreement in Appendix A.
Corporate Services provided by Fortis Inc.	There is no written agreement between Fortis Inc. and CNPI. FortisOntario allocates corporate services charged to it pursuant to the fourth agreement in Appendix A.
Admin Services provided by CNPI-Fort Erie	These are internally allocated costs. There is no agreement as it is the same legal entity.
Rent charge from CNPI-Fort Erie	These are internally allocated costs, based upon the Net Lease in Appendix D.

c) The first Services Agreement in Appendix A provides for these services; however, no shared services are currently being provided by Cornwall Electric to CNPI – Port Colborne.

d) The third Services Agreement in Appendix A provides for these services; however, no services are currently being provided by FortisOntario Generation to CNPI – Port Colborne.

INTERROGATORY # 23

Ref: Exhibit 4/Tab 2/Schedule 4, Appendix A

a) With respect to the first Service Agreement in Appendix A (where Cornwall is the service provider):
• Please explain the reference to "approved rate of return" in paragraph 2.01.
• Who approves Cornwall's rate of return?
• What is the "rate of return" used to for purpose of costing services to CNP-PC in 2007, 2008, 2008 and 2009.

b) With respect to the third Service Agreement in Appendix A (where FortisOntario Generation is the service provider):
• Please explain the reference to "approved rate of return" in paragraph 2.01.
• Who approves FOGEN's rate of return?
• What is the "rate of return" used to for purpose of costing services to CNP-PC in 2007, 2008, 2008 and 2009.

c) With respect to the fourth Service Agreement in Appendix A (where FortisOntario Inc. is the service provider):
• Please explain the reference to "approved rate of return" in paragraph 2.01.
• Who approves FortisOntario Inc's rate of return?
• What is the "rate of return" used to for purpose of costing services to CNP-PC in 2007, 2008, 2008 and 2009.

d) Please provide a copy of the Service Agreement for the services provided by Fortis Inc. to CNPI (and CNP-PC).

RESPONSE:

a) There have been no services provided by Cornwall Electric to CNPI – Port Colborne in 2007, 2008, and 2009. Accordingly, a fee for services is not applicable. Further, there is no reference in Section 1.01 to an "approved" rate of return.

b) There have been no services provided by FOGEN to CNPI – Port Colborne in 2007, 2008, and 2009. Accordingly, a fee for services is not applicable. Further, there is no reference in Section 1.01 to an "approved" rate of return.

c) For the purpose of costing services to CNPI – Port Colborne in 2007, 2008, and 2009, the fully loaded cost of the service/cost based pricing has been used for services provided by FortisOntario to CNPI – Port Colborne. Accordingly, the "reasonable rate of return" has not been calculated or applied. Please note that there is no reference in Section 1.01 to an "approved" rate of return. In respect of the allocation of costs for the Fort Erie Service Centre, a market-based pricing has been used for the determination of rent.

d) There is no written agreement between Fortis Inc. and CNPI for services. FortisOntario allocates these costs to CNPI pursuant to the fourth services agreement in Appendix A.

INTERROGATORY # 24

Ref: Exhibit 4/Tab 2/Schedule 4, Appendix B

a) With respect to page 2, please confirm that equipment time is also logged by CNPI's transmission business and a portion of the costs of Transportation and Work Equipment is allocated to the transmission business.

b) The Appendix only contains the allocation factors for expense items. Please provide a schedule that sets out the allocation factors for 2006, 2007, 2008 and 2009 for all business centres allocated the following costs:
• Information Technology Hardware and Software (broken down between costs driven by number of workstations and major systems),
• Transport and Work Equipment,
• The warehouse and garage components of the Service Centre Rent and Maintenance

RESPONSE:

a) CNPI's Transmission business is a fully allocated segment of CNPI and thus receives the relevant portion of the costs of Transportation and Work Equipment. Capital costs are allocated as discussed in the BDR Report. Operating costs for vehicles are charged through the labour rates as discussed in the response to SEC Interrogatory # 6.

b) Please see response to Question VECC-PC-07-a.

INTERROGATORY # 25

Ref: Exhibit 4/Tab 2/Schedule 5, page 4: Appendix A and Appendix B

a) Please indicate the total incentive payments for 2006 and 2007 including those deemed to be "primarily shareholder related".

b) Please clarify whether the employee numbers and costs in Appendix A include:
• Only those employees directly employed at CNP-PC or, also,
• Employees of affiliates where costs can be directly allocated to CNPPC or, also,
• Employees of affiliates where costs are allocated (using an allocation factor).
If the first, please explain why there are a fractional number of employees in each category.

RESPONSE:

a) The total incentive payment included in CNPI's rate applications for all three service territories for 2006 is $202,285. The portion allocated to CNPI-PC for 2006 is $63,528. The total incentive payment included in CNPI's rate applications for all three service territories for 2007 is $209,190. The portion allocated to CNPI-PC for 2007 is $65,711. These incentive payments do not include any component that is "primary shareholder related".

b) The employee numbers in Appendix A are based on the total number of full-time employees in CNPI (i.e. 70 in 2009 Test Year). These have been allocated to CNPI-PC based on the cost allocation methodology as set out in the BDR Report. As well, the executives, who are employees of an affiliate, FortisOntario, have been allocated to CNPI-PC based on the allocation method as set out in the BDR Report. The application of the cost allocation methodology results in a fractional number of employees in each category.

INTERROGATORY # 26

Ref: i) Exhibit 4/Tab 3/Schedule 2, page 1
ii) Exhibit 4/Tab 3/Schedule 1, page 1

a) Why are the tax calculations segregated for transmission versus distribution but not for the 3 distribution business units?

b) Please provide a schedule that sets out the 2009 rate base for each of the four regulated units of CNPI.

RESPONSE:

a) CNPI's income taxes and capital structure are managed on a combined basis for the three regulated distribution business units and the one regulated transmission business unit. It is management's objective to eventually harmonize the electricity rates for the three distribution business units beginning in 2009 with Fort Erie and Eastern Ontario Power. By Order of the Board (see Board Decision and Order RP-2001-4001 in Exhibit 1 Tab 1 Schedule 14 Appendix A), Port Colborne electricity rates cannot be harmonized until the lease expires in 2012. Assuming the purchase option is exercised pursuant to the lease, management will seek to harmonize Port Colborne electricity rates in 2012. Since the three distribution operations are rebasing in 2009 and income taxes are managed on a combined basis, tax calculations were not segregated for the three regulated distribution business units.

Equity return on rate base was used to calculate the distribution taxable income and thus, the respective rate base of each business unit was use to allocate Income tax amongst the three regulated business units.

The transmission business unit will not be harmonized with the distribution business units and will file a separate rate application. Therefore, tax calculations for transmission have been segregated.

b) The 2009 rate base for CNPI's distribution business units are as follows:

CNPI - Fort Erie	$37,463,907
CNPI - Port Colborne	$13,295,018
CNPI - Eastern Ontario Power	$ 7,756,830
	$58,516,355

CNPI's transmission business is not rebasing in this cost of service Application and therefore its rate base is not relevant.

INTERROGATORY # 27

Ref: Exhibit 4/Tab 3/Schedule 5, page 1

a) Please explain the significance of the last paragraph, i.e., how does it impact the calculation of the 2009 revenue requirement.

RESPONSE:

The combined management of income taxes and capital structure by CNPI does not impact the revenue requirement. CNPI has not incorporated interest expense additions and deductions in the calculation of income taxes. Management intends to generally set CNPI's capital structure in line with the OEB's deemed capital structure.

INTERROGATORY # 28

Ref: i) Exhibit 5/Tab 1/Schedule 4, page 1
ii) Exhibit 3/Tab 1/Schedule 2, page 1

a) What is the source (e.g., year) for the distribution revenue values used to allocate Account #1508 to customer classes? It does not appear to match any of the values reported in Exhibit 3.

RESPONSE:

a) The distribution revenue values used to allocate Account #1508 to customer classes was calculated using existing rates and non-weather normalized 2009 forecast values.

INTERROGATORY # 29

Ref: Exhibit 8/tab 1/Schedule 1

a) Please clarify the allocation process described at page 1 (lines 15-18). The first sentence suggests the $9,960 was allocated to all customer classes using CWNB; while the next sentence suggests that the $9,960 is attributable solely to customers with distributed generation.

b) The Board's Direction on Cost Allocation (EB-2005-0317, page 32) defines "direct allocation" as the allocation of identifiable OM&A activities to one customer classification. Please confirm that for Accounts #1920 and #1925 where CNP-PC states that it is using "direct allocation", the costs identified are allocated to more than one customer class.

c) Please confirm that, by virtue of the formula used in the OEB's cost allocation model, OM&A costs that are deemed to be directly allocated are excluded from the allocation base for A&G costs.

d) With reference to the comment on page 3 that CNP-PC's customer profile has not changed significantly, please complete the following table:
• kWh by Customer Class (delivered)
Customer Cost Allocation Filing 2009 Application
Class (all) kWh % of Total kWh % of Total
• Customer/Connection Count
Customer Cost Allocation Filing 2009 Application Class (where applicable)
Number % of Total Number % of Total

e) Based on the results from part (d), please comment on the appropriateness of assuming that the revenue requirement proportions from the Updated 2006 Cost Allocation study can be used for setting 2009 rates.

RESPONSE:

a) In the first run of the Cost Allocation Informational Filing, $9,960 was directly allocated to the GS 50 to 4,999 kW class. This allocation was specified on Tab I9 Direct Allocation. Up until 2006, CNPI incurred additional costs for billing the two GS 50 to 4,999 kW customers with embedded generation. This cost was estimated at $9,960 in account 5315; Customer Billing. This was a direct allocation.

In the second run, there was no direct allocation of the $9,960 and the entirety of account 5315, was allocated on CWNB. This was done because on a go forward basis, CNPI had accommodated the embedded generation customers in its billing functionality and no additional specific costs were incurred.

b) Accounts 1920; Computer Equipment and Hardware, and 1925; Computer Software, are accounts that reside, for accounting purposes in CNPI – Fort Erie. The accounts are allocated to CNPI's business units on the basis of its shared services methodology. In order to allocate the CNPI – Port Colborne allocation of these accounts to the customer classes, the amounts were entered in the 1920 and 1925 account rows on Tab I9 Direct allocation and then allocated to all customer classes.

c) CNPI can confirm that, by virtue of the formula used in the OEB's cost allocation model, OM&A costs that are deemed to be directly allocated are excluded from the allocation base for A&G costs. However, in CNPI's case, direct allocation model functionality was used to allocate costs to all customer classes as discussed above.

d) kWh by Customer Class

Customer Class (all)	Cost Allocation Filing		2009 Application	
	kWh	% of Total	kWh	% of Total
Residential	62,256,160	32.0%	64,972,406	33.7%
GS < 50	26,781,130	13.7%	25,831,151	13.4%
GS > 50	104,648,698	53.7%	99,392,250	51.6%
Street Light	514,213	0.3%	1,792,552	0.9%
Sentinel	4,941	0.0%	12,725	0.0%
USL	624,456	0.3%	581,173	0.3%
Total	194,829,598	100.0%	192,582,257	100.0%

Customer Connection Count

Customer Class (all)	Cost Allocation Filing		2009 Application	
	Number	% of Total	Number	% of Total
Residential	8,064	72.4%	8,155	72.7%
GS < 50	916	8.2%	934	8.3%
GS > 50	72	0.6%	81	0.7%
Street Light	2,015	18.1%	1,985	17.7%
Sentinel	46	0.4%	36	0.3%
USL	19	0.2%	19	0.2%
Total	11,132	100.0%	11,210	100.0%

e) It is CNPI – Port Colborne’s position that the proportions have not changed significantly and that the 2006 Cost Allocation Informational Filing can be used for setting 2009 electricity distribution rates.

INTERROGATORY # 30

Reference: Exhibit 8/Tab 1/Schedule 2, pages 1 & 3
Preamble: For 2009 CNP=PC is proposing to drop the Backup/Standby class and include the existing two customers in with the GS>50 class.

a) Based on the Cost Allocation Informational filing what would be the overall revenue to cost ratio if the revenues and costs associated with both the GS>50 and the Standby/Backup rate classes were combined from RUN #2 and an aggregated revenue to cost ratio determined?

b) Please explain why it would not be appropriate to use the results of part (a) for purposes of the 2009 rates.

c) Please clarify whether the table on page 3 is for CNP-Port Colborne or CNP-Fort Erie. If the later, please correct.

RESPONSE:

For 2009 CNP – Port Colborne is not proposing to drop the Backup/Standby class and include the existing two customers in with the GS>50 class. Distribution revenues for these two customers are already included with the General Service 50 to 4,999 kW class. The Standby/Backup class is distinguished by the presence of the standby charge and based on CNPI – Port Colborne's forecast, which was prepared after meeting with the customers; their electricity usage is anticipated such that no standby revenue will be realized in 2009. CNPI – Port Colborne has asked the Board for approval of its current standby charge.

a) In the Cost Allocation Informational Filing the Standby/Backup class was maintained separately. However all distribution volumes and distribution revenues had been assigned to the General Service 50 to 4,999 kW class.

   CNPI – Port Colborne has removed the Standby/Backup class from a trial run of the cost allocation model and sheet O1, an excerpt from the Model is shown below. There is no material change to the class ratios.

2006 Cost Allocation Information Filing
Canadian Niagara Power Inc. - Port Colborne

EB-2005-0345 EB-2007-0001
Thursday, January 18, 2007
Sheet O1 Revenue to Cost Summary Worksheet - Second Run

Rate Base Assets			1	2	3	7	8	9
		Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
crev	Distribution Revenue (sale)	**$4,455,806**	$2,429,942	$587,789	$1,384,594	$38,548	$1,228	$13,705
mi	Miscellaneous Revenue (mi)	**$452,227**	$292,622	$71,649	$63,771	$6,571	$159	$6,350
	Total Revenue	**$4,908,033**	**$2,722,564**	**$659,437**	**$1,448,365**	**$45,119**	**$1,387**	**$20,055**
	Expenses							
di	Distribution Costs (di)	**$729,989**	$374,618	$100,130	$163,472	$42,016	$716	$1,974
cu	Customer Related Costs (cu)	**$714,862**	$526,854	$121,029	$56,336	$1,573	$92	$8,977
ad	General and Administration (ad)	**$2,473,699**	$1,531,553	$377,600	$385,911	$75,113	$1,388	$18,349
dep	Depreciation and Amortization (dep)	**$349,221**	$166,520	$48,167	$95,113	$13,407	$228	$746
INPUT	PILs (INPUT)	**$33,236**	$15,378	$4,617	$9,394	$1,221	$21	$71
INT	Interest	**$239,518**	$110,820	$33,273	$67,702	$8,797	$150	$510
	Total Expenses	**$4,540,524**	**$2,725,744**	**$684,816**	**$777,929**	**$142,127**	**$2,595**	**$30,627**
	Direct Allocation	**$63,466**	**$47,967**	**$10,897**	**$2,996**	**$222**	**$13**	**$1,371**
NI	Allocated Net Income (NI)	**$304,043**	$140,675	$42,237	$85,941	$11,166	$190	$647
	Revenue Requirement (includes NI)	**$4,908,033**	$2,914,387	$737,951	$866,865	$153,516	$2,798	$32,645
		Revenue Requirement Input equals Output						
	Rate Base Calculation							
	Net Assets							
dp	Distribution Plant - Gross	**$3,850,167**	$1,784,948	$534,158	$1,084,428	$142,855	$2,434	$8,240
gp	General Plant - Gross	**$1,504,062**	$696,354	$208,809	$424,609	$55,462	$945	$3,208
accum dep	Accumulated Depreciation	**($798,524)**	($372,092)	($110,499)	($222,926)	($30,326)	($517)	($1,731)
co	Capital Contribution	**($37,624)**	($18,539)	($4,892)	($9,311)	($1,941)	($33)	($96)
	Total Net Plant	**$4,518,081**	**$2,090,671**	**$627,576**	**$1,276,801**	**$166,050**	**$2,829**	**$9,622**
	Directly Allocated Net Fixed Assets	**$381,646**	**$288,448**	**$65,529**	**$18,014**	**$1,336**	**$76**	**$8,244**
COP	Cost of Power (COP)	**$13,535,922**	$4,325,290	$1,860,638	$7,270,541	$35,725	$343	$43,385
	OM&A Expenses	**$3,918,550**	$2,433,026	$598,759	$605,719	$118,703	$2,196	$29,300
	Directly Allocated Expenses	**$0**	$0	$0	$0	$0	$0	$0
	Subtotal	***$17,454,472***	***$6,758,316***	***$2,459,396***	***$7,876,261***	***$154,428***	***$2,539***	***$72,685***
	Working Capital	**$2,618,171**	**$1,013,747**	**$368,909**	**$1,181,439**	**$23,164**	**$381**	**$10,903**
	Total Rate Base	**$7,517,897**	**$3,392,866**	**$1,062,014**	**$2,476,253**	**$190,550**	**$3,286**	**$28,768**
		Rate Base Input equals Output						
	Equity Component of Rate Base	**$3,758,949**	**$1,696,433**	**$531,007**	**$1,238,127**	**$95,275**	**$1,643**	**$14,384**
	Net Income on Allocated Assets	**$304,043**	**($51,147)**	**($36,276)**	**$667,441**	**($97,230)**	**($1,220)**	**($11,943)**
	Net Income on Direct Allocation Assets	**$33,454**	**$25,285**	**$5,744**	**$1,579**	**$117**	**$7**	**$723**
	Net Income	**$337,497**	**($25,862)**	**($30,532)**	**$669,020**	**($97,113)**	**($1,214)**	**($11,220)**
	RATIOS ANALYSIS							
	REVENUE TO EXPENSES %	**100.00%**	93.42%	89.36%	167.08%	29.39%	49.58%	61.43%
	EXISTING REVENUE MINUS ALLOCATED COSTS	**($0)**	($191,822)	($78,513)	$581,500	($108,397)	($1,411)	($12,590)
	RETURN ON EQUITY COMPONENT OF RATE BASE	8.98%	-1.52%	-5.75%	54.03%	-101.93%	-73.87%	-78.00%

b) It would not be appropriate to use the result of Part (a) for purposes of the 2009 rates since no distribution revenue or capacity was assigned to the Standby/Backup class and it did not materially affect the RUN as indicated above.

c) The table on page 3 should read CNPI – Port Colborne.

INTERROGATORY # 31

Ref: i) Exhibit 8/Tab 1/Schedule 2, page 3
ii) Exhibit 9/Tab 1/Schedule 1, page 9, lines 21-26
iii) Exhibit 9/Tab 1/Schedule 1, Appendix A – Cost Allocation Review Tab

a) Please confirm that for purposes of the Cost Allocation Informational Filing:
• The Revenues are based on distribution rates (excluding the discounts for transformer ownership allowance)
• The Costs include the cost of the Transformer Ownership Allowance
• The cost of the Transformer Ownership Allowance is allocated to all customer classes

b) In reference (iii) the transformer allowance is allocated directly to the GS>50 class. If the response to part (a) is yes, please explain why in reference (iii) the Cost Allocation Revenue Requirement used to derive the Revenue Requirement wasn't adjusted to remove the allocation of the transformer ownership allowance.

c) Please confirm that (per Exhibit 9, Tab 1, Schedule 1, page 9), CNP-PC is proposing to allocate the cost of the Transformer Ownership Allowance to just the GS>50 class.

d) Please provide the results of an alternative cost allocation run which is consistent with CNP-PC's proposed treatment of the Transformer Ownership Allowance where:
• The Revenues by class are based the rates reduced by the transformer ownership allowance where applicable
• The Costs allocated exclude the "cost" of the Transformer Ownership Allowance.
(Note: For purposes of the response please just file the revise Output Sheet O1)

RESPONSE:

a) CNPI confirms that the revenues are bases on distribution rates that include the allowance for transformer ownership allowance. The costs include the transformer ownership allowance and that the transformer ownership allowance is allocated to all classes.

b) The revenue requirement by customer class was not modified to remove the allocation of the transformer allowance to the customer classes. CNPI did not, at the time, believe that the allocation across the classes would significantly influence the final outcome of the rate design. CNPI – Port Colborne will, if so directed, adjust the allocation to the classes to remove the allocation of the transformer allowance.

c) CNPI confirms that in its current Applications the cost of the transformer ownership allowance is allocated to just the GS>50 class.

d) To proxy the request in this interrogatory, CNPI has removed the transformer allowance costs from Tab I3 Cell F15 of the CNPI-PC_CostAllocationFiling_20080815.xls. Sheet O1 showing the impact of this modification is shown below.

2006 Cost Allocation Information Filing
Canadian Niagara Power Inc. - Port Colborne

EB-2005-0345 EB-2007-0001
Thursday, January 18, 2007

Sheet O1 Revenue to Cost Summary Worksheet - Second Run

			1	2	3	7	8	9	11
Rate Base Assets		**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Back-up/Standby Power**
crev	Distribution Revenue (sale)	**$4,455,806**	$2,429,942	$587,789	$1,384,594	$38,548	$1,228	$13,705	$0
mi	Miscellaneous Revenue (mi)	**$452,227**	$292,622	$71,649	$63,771	$6,571	$159	$6,350	$11,105
	Total Revenue	**$4,908,033**	**$2,722,564**	**$659,437**	**$1,448,365**	**$45,119**	**$1,387**	**$20,055**	**$11,105**
	Expenses								
di	Distribution Costs (di)	**$593,260**	$305,434	$81,432	$133,105	$34,954	$596	$1,618	$36,122
cu	Customer Related Costs (cu)	**$714,862**	$526,854	$121,029	$56,336	$1,573	$92	$8,977	$0
ad	General and Administration (ad)	**$2,473,699**	$1,561,138	$381,694	$368,357	$69,723	$1,307	$19,598	$71,881
dep	Depreciation and Amortization (dep)	**$349,221**	$166,520	$48,167	$95,113	$13,407	$228	$746	$25,038
INPUT	PILs (INPUT)	**$33,236**	$15,378	$4,617	$9,394	$1,221	$21	$71	$2,535
INT	Interest	**$239,518**	$110,820	$33,273	$67,702	$8,797	$150	$510	$18,265
	Total Expenses	**$4,403,795**	**$2,686,144**	**$670,213**	**$730,008**	**$129,674**	**$2,394**	**$31,520**	**$153,841**
	Direct Allocation	**$63,466**	**$47,967**	**$10,897**	**$2,996**	**$222**	**$13**	**$1,371**	**$0**
NI	Allocated Net Income (NI)	**$304,043**	$140,675	$42,237	$85,941	$11,166	$190	$647	$23,186
	Revenue Requirement (includes NI)	**$4,771,304**	$2,874,787	$723,348	$818,944	$141,062	$2,597	$33,538	$177,027
		Revenue Requirement Input equals Output							
	Rate Base Calculation								
	Net Assets								
dp	Distribution Plant - Gross	**$3,850,167**	$1,784,948	$534,158	$1,084,428	$142,855	$2,434	$8,240	$293,103
gp	General Plant - Gross	**$1,504,062**	$696,354	$208,809	$424,609	$55,462	$945	$3,208	$114,676
accum dep	Accumulated Depreciation	**($798,524)**	($372,092)	($110,499)	($222,926)	($30,326)	($517)	($1,731)	($60,433)
co	Capital Contribution	**($37,624)**	($18,539)	($4,892)	($9,311)	($1,941)	($33)	($96)	($2,812)
	Total Net Plant	**$4,518,081**	**$2,090,671**	**$627,576**	**$1,276,801**	**$166,050**	**$2,829**	**$9,622**	**$344,533**
	Directly Allocated Net Fixed Assets	**$381,646**	**$288,448**	**$65,529**	**$18,014**	**$1,336**	**$76**	**$8,244**	**$0**
COP	Cost of Power (COP)	**$13,535,922**	$4,325,290	$1,860,638	$7,270,541	$35,725	$343	$43,385	$0
	OM&A Expenses	**$3,781,821**	$2,393,426	$584,156	$557,798	$106,249	$1,995	$30,194	$108,003
	Directly Allocated Expenses	**$0**	$0	$0	$0	$0	$0	$0	$0
	Subtotal	***$17,317,743***	***$6,718,716***	***$2,444,793***	***$7,828,340***	***$141,975***	***$2,338***	***$73,578***	***$108,003***
	Working Capital	**$2,597,661**	**$1,007,807**	**$366,719**	**$1,174,251**	**$21,296**	**$351**	**$11,037**	**$16,200**
	Total Rate Base	**$7,497,388**	**$3,386,926**	**$1,059,823**	**$2,469,065**	**$188,682**	**$3,256**	**$28,902**	**$360,734**
		Rate Base Input equals Output							
	Equity Component of Rate Base	**$3,748,694**	**$1,693,463**	**$529,912**	**$1,234,533**	**$94,341**	**$1,628**	**$14,451**	**$180,367**
	Net Income on Allocated Assets	**$440,772**	**($11,547)**	**($21,673)**	**$715,362**	**($84,777)**	**($1,020)**	**($12,836)**	**($142,737)**
	Net Income on Direct Allocation Assets	**$33,454**	**$25,285**	**$5,744**	**$1,579**	**$117**	**$7**	**$723**	**$0**
	Net Income	**$474,226**	**$13,737**	**($15,929)**	**$716,941**	**($84,660)**	**($1,013)**	**($12,114)**	**($142,737)**
	RATIOS ANALYSIS								
	REVENUE TO EXPENSES %	**102.87%**	94.70%	91.16%	176.86%	31.99%	53.41%	59.80%	6.27%
	EXISTING REVENUE MINUS ALLOCATED COSTS	**$136,729**	($152,222)	($63,910)	$629,421	($95,943)	($1,210)	($13,483)	($165,923)
	RETURN ON EQUITY COMPONENT OF RATE BASE	12.65%	0.81%	-3.01%	58.07%	-89.74%	-62.22%	-83.82%	-79.14%

INTERROGATORY # 32

Ref: i) Exhibit 8/Tab 1/Schedule 2, pages 1-3
ii) Exhibit 9/Tab 1/Schedule 1, Appendix A-Cost Allocation Review Tab

a) Please confirm whether or not CNP-PC's Cost Allocation Informational filing included LV Costs as part of the revenue requirement. If yes, please indicate where in the Cost Allocation Informational filing this cost is accounted for.
b) If the response to part (a) is no, why – in Appendix A - are LV costs included in the revenue requirement (I.e., $5,990,730) that is being allocated using the percentages derived from the Cost Allocation Revenue Requirement?

RESPONSE:

a) No, the LV Costs were not included as part of the revenue requirement in CNPI – Port Colborne's Cost Allocation Informational filing. As shown on Tab I3 TB Data, the revenue requirement used in the Cost Allocation Informational Filing equaled the approved revenue requirement plus the approved transformer ownership allowance minus the approved low voltage wheeling adjustment.

b) Low voltage wheeling costs were included in the revenue requirement of $5,990,730, which is allocated on TAB [Cost Allocation Review] in column F. The low voltage wheeling allocations to the classes in column I is subtracted from column F to yield the 2009 Base Revenue Requirement less Low Voltage in column J.

In essence, the rate design model does remove the low voltage wheeling costs, but in this case, after the determination of the Service Revenue Requirement. The intent was to remove the low voltage wheeling cost, however mathematically the allocations are slightly different than they would have otherwise been. The table below illustrates the difference had the low voltage not been included as part of the allocated revenue requirement.

Comparison of Proposed Allocations to Allocations with Low Voltage Wheeling Costs Removed				
Customer Class	Allocation of 2009 Base Revenue with Transformer Allowance			
	CNPI – PC Proposed		As Per this IR	
Residential	3,366,124	57.78%	3,359,889	57.67%
GS < 50 kW	852,981	14.64%	852,303	14.63%
GS > 50 kW	1,384,636	23.77%	1,392,304	23.90%
Street Lights	183,180	3.14%	182,575	3.13%
Sentinel Lights	3,314	0.06%	3,303	0.06%
USL	35,831	0.62%	35,693	0.61%
Total	$5,826,066	100%	$5,826,066	100%

Note that there may be slight deviations in the totals shown here due to rounding.

The result is a slightly different allocation to the classes and this methodology can be incorporated in a subsequent rate design.

INTERROGATORY # 33

Ref: Exhibit 9/Tab 1/Schedule 1 (including Appendix A)

a) With respect to page 6, please explain why the 2009 amount included for the transformer ownership allowance is $141,484 when the 2009 amount in Appendix A (Transformer Allowance Tab) is $142,119.

b) With respect to page 10 and Appendix A (Low Voltage Allocation Tab), please provide a schedule setting out the derivation of the allocation percentages used in Appendix A.

c) With respect to page 12 (lines 9-16), please provide a schedule that sets out the allocation of revenues by customer class based on:
   • The 2006 approved EDR (i.e., as discussed in the application)
   • The 2009 billing determinants at 2008 rates (Note: The rates used should exclude any LV cost recovery as well as the smart meter rate adder. However, the rates and revenues should capture the reduction due to the transformer ownership allowance)

d) With respect to page 15, please explain why under the proposal the Residential revenue to cost ratio is virtually the same as in the Cost Allocation Informational filing (i.e., 93.42% vs. 93.43%) but the bill impact is much higher (i.e., 7.1% vs. 4.6%).

e) With respect to pages 15-16, given that the proportion of revenue requirement being allocated to the Residential class is only increasing from 54.53% to 55.33%, why is it necessary to have virtually a 10 percentage point increase in the proportion of revenue allocated to the fixed service charge in order to maintain a charge that is "consistent with recent increases allowed in the 2nd Generation IRM"?

f) With respect to page 19, please explain why the bill impact (7.9%) for USL is less using the 61.43% R/C ratio from the 2006 Cost Allocation than it is under the 2009 proposal where the bill impact is 9.9% but the R/C ratio is lower (52.51%). One would have expected a higher bill impact if a higher R/C ratio is used.

RESPONSE:

a) As explained in other interrogatories, CNPI – Port Colborne, during the course of these interrogatories, discovered an error in its rate design model. The kW and kWh volumes, including the transformer ownership allowance, used as rate determinants were inadvertently averaged over 2008 and 2009. This error has been corrected in a new revision of the rate design models.

These revised models will be submitted to the Board, correcting this error and accounting for other matters arising from these interrogatories. The correct rate determinant for the transformer ownership allowance is 236,865 kW and $142,119.

b) The allocation percentages are those derived in the Board Approved 2006 EDR Tab 7-2 Allocation - LV – Wheeling.

The following data has bee extracted from the Board Approved 2006 EDR Model.

Amount allocated on this sheet:-- Low Voltage Wheeling Costs B.R.R. #2 **$19,027**	Allocation Percentages	Allocated $
RESIDENTIAL		
Regular	29.38%	5,589
GENERAL SERVICE		
Less than 50 kW	11.77%	2,240
Greater than 50 kW (to 3000 kW)	58.63%	11,156
Greater than 50 kW Time of Use	0.00%	0
Unmetered Scattered Load	0.00%	0
Sentinel Lighting	0.00%	0
Street Lighting	0.22%	41
Back-up/Standby Power	0.00%	0
TOTALS	100.00%	19,027

c)

Canadian Niagara Power - Port Colborne
Response to VECC - Port Colborne - 33c

		2009 Volumes		2006 EDR Based Rates		2009 Revenue		
Customer Class	No. of Customers / Connections	kWh	kW	Monthly Service Charge	Volumetric Charge	Monthly Service Charge	Volumetric Charge	Total Class Distribution Revenue
Residential	8,144	64,972,406		19.07	0.0182	1,863,559	1,182,498	3,046,056
General Service Less Than 50 kW	933	25,831,151		38.77	0.0118	434,069	304,808	738,876
General Service 50 to 4,999 kW	81	99,392,250	377,959	741.33	3.0743	716,125	1,161,958	1,878,083
Unmetered Scattered Load	19	581,173		38.77	0.0118	8,840	6,858	15,697
Sentinel Lighting	37	12,725	38	3.23	2.7811	1,434	106	1,540
Street Lighting	1,988	1,792,552	5,433	1.74	1.2716	41,509	6,908	48,418
	11,201	192,582,257	383,429			3,065,535	2,663,136	5,728,671

d) As footnoted on the table shown on page 15, the Revenue to Cost Ratio that is shown for the “Class Allocation Consistent with 2006 Approved EDR Rates” is the Revenue to Cost Ratio determined in the CNPI – Port Colborne Cost Allocation Informational Filing.

e) The residential class was allocated 54.53% of the 2006 EDR Base Revenue Requirement which was $2,429,956. The proposed allocation is 55.33% of the 2009 proposed Base Revenue Requirement which is $3,145,042; an increase of $715,086.

Under the 2006 Board Approved EDR, 61.8% of this increase would be allocated to the fixed service charge. To compensate for this increase in the monthly service charge component of the distribution rates it was necessary to change the allocation to fixed component to 51.5%.

f) As footnoted on the table shown on page 19, the Revenue to Cost Ratio that is shown for the “Class Allocation Consistent with 2006 Approved EDR Rates” is the Revenue to Cost Ratio determined in the CNPI – Port Colborne Cost Allocation Informational Filing.

INTERROGATORY # 34

Ref: i) Exhibit 9/Tab 1/Schedule 1, Appendix A

a) Based on a recent 12 consecutive months of actual billing data, please indicate the percentage of total residential customers that:
- Consume less than 100 kWh per month
- Consume 100 -> 250 kWh per month
- Consume 250 -> 500 kWh per month
- Consume 500 -> 750 kWh per month
- Consume 750 -> 1000 kWh per month

RESPONSE:

Distribution of Residential Customers based on Monthly Consumption	
Consume less than 100 kWh per month	2.85%
Consume 100 -> 250 kWh per month	7.53%
Consume 250 -> 500 kWh per month	26.59%
Consume 500 -> 750 kWh per month	27.19%
Consume 750 -> 1000 kWh per month	17.58%
Consume > 1000 kWh per month	18.26%