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

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

Ontario

BY E-MAIL

July 27, 2010

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

Dear Ms. Walli:

Re: Algoma Power Inc.
2010 and 2011 Distribution Rates Application
Board Staff Interrogatories
Board File No. EB-2009-0278

Attached are the Board staff Interrogatories for the above mentioned proceeding.

Please forward the attached to Algoma Power Inc. and to all other registered parties to this proceeding.

Yours truly,

Original Signed By

Richard Battista
Project Advisor – Applications & Regulatory Audit

BOARD STAFF INTERROGATORIES
ALGOMA POWER INC.
2010 AND 2011 RATES
EB-2009-0278

Administration

1. Ref: Exhibit 1/Tab1/Schedule 2
   Algoma Power chose to file an application to set rates for each of 2010 and 2011 using a cost of service based approach.

   a) Please provide the reasons why Algoma Power did not consider using the Board's Incentive Regulation Mechanism to set rates for 2011.
   b) With respect to the setting of rates for 2012, does Algoma intend to file a cost of service application or will it file under the Incentive Regulation Mechanism?

2. Ref: Exhibit 1/Tab1/Schedule 2
   Algoma Power's filed its application on June 1, 2010 which is after the April 30, 2010 closing date for 2010 cost of service rate applications as set out in the Board's April 20, 2010, letter: "Application for Rates for the 2010 Rate Year – Direction Regarding Filing."

   Please provide a comprehensive explanation for the four-week delay in Algoma Power's filing of its 2010 cost of service rate application.

3. Ref: Exhibit 1 /Tab 1/ Schedule 17
   With respect to the Board's decision on GLPL's "rate mitigation plan" and the subsequent appeal to the Divisional Court (which was dismissed), Algoma Power notes that GLPL was granted leave to appeal to the Ontario Court of Appeal, and that appeal was heard on April 29, 2010. Board staff understands that the Ontario Court of Appeal has ruled in the aforementioned matter.

   a) Please file a copy of the court's ruling.
   b) Please indicate what action, if any, Algoma intends to take in light of the court's decision.

4. Ref: Exhibit 1 /Tab 1/ Schedule 2-1
   Please provide a copy of Algoma Power's current Tariff of Rates and Charges.

5. Ref: Exhibit 1 /Tab 2 /Schedule 2
   The budget process Algoma Power used to prepare its budget for the upcoming year is described in Exhibit 1 Tab 2 Schedule 2.

   a) Please describe the method Algoma Power used to calculate the impact on costs of the introduction on July 1, 2010 of the Harmonized Sales Tax ("HST").
   b) Please provide the dollar amount impact of the HST on OM&A and Capital for test years 2010 and 2011.

6. Ref: Exhibit 1 /Tab 2 /Schedule 1
   a) Please confirm that the revenue requirement numbers for 2010 and 2011 are based on CGAAP, and not IFRS, accounting principles.
   b) In which fiscal year will Algoma Power begin reporting its (audited) actual results on an IFRS basis?

7. Ref: Responses to Letter of comment
   a) Subsequent to the publication of the Notice of Application, did Algoma Power receive any letters of comment?
   b) If so, did Algoma Power reply to the customer? If so, please file the letter of response?
   c) If Algoma Power did not reply, please explain why a response was not considered necessary.

8. Ref: Exhibit 1/ Tab 2/ Schedule 3 p1
   Algoma Power indicates that after the finalization of the *Asset Amortization Study* prepared by Kinectrics the amortization rates in the 2011 Test Year would be updated based on the study and that subsequent evidence will be filed.

   a) In light of the Board's letter dated, July 8, 2010, to all Electricity Distributors re: *The depreciation study for use by electricity distributors….*, please confirm whether or not Algoma Power will file updated evidence in this proceeding.
   b) If so please state the date by which this evidence will be filed.

Rate Base and Capital

9. Ref: Exhibit 2 /Tab 4 /Schedule 4 p.1-2
   Algoma Power states that its proposed overhead capitalization methodology is consistent with the methodology used by CNPI and approved by the Board in EB-2008-0222. The amounts capitalized for 2010 and 2011 is $821,000 and $874,000 respectively.

   Please calculate the amounts that would have been proposed for capitalization under the methodology used by GLPL.

10. Ref: Exhibit 2/ Tab 4/ Schedule 4 p.2 n 11-12
    The evidence states: "API is aware of the Board's letter dated February 24, 2010, *Accounting for Overhead Costs Associated with Capital Works,* and therefore is requesting specific approval."

    Please clarify to what exactly in the evidence this requested approval pertains.

11. Ref: Exhibit 2 /Tab 2 /Schedule 1
    The footnote in the Fixed Assets Continuity Statement for 2009 reads " The splitting out of the distribution assets from Great Lakes Power Limited to Great Lakes Power Distribution Inc. on July 1, 2009 did not include the building on Sackville Road in Sault Ste. Marie,

certain fleet vehicles, and the information technology hardware and software. The removal of those assets was based on the net book value."

Please explain the difference in treatment between "splitting out of assets" versus "removing the assets based on the net book value".

12. Ref: Exhibit 2 /Tab 3/ Schedule 3
    Please provide a "source reference" (e.g. 2007 tariff sheet, Nov 2009 RRP) for each of the rates used to calculate the Cost of Power Amount that is included in the proposed Working Capital for 2010 and 2011.

13. Ref: Exhibit 2 /Tab 4/ Schedule 2
    With respect to the High Risk Conductor Replacement Program (50 km) Capital expenditures of $4,107,674 in 2009, Algoma Power notes that the accounting transfer from Work in Progress to Rate Base was completed in early 2009 for many of the projects placed in service late in 2008. As a result, approximately $1.87M of the $4.11M total above relates to 2008 projects.

    Please indicate where this transfer is captured in the Fixed Asset Continuity Statements that are presented in Exhibit 2 Tab 2 Schedule 1.

14. Ref: Exhibit 2/ Tab 4 /Schedule 2
    Algoma Power's capital expenditures for 2007, 2008 and 2009 were approximately $8.2 million, $9.1 million and $9.3 million respectively. This averages to about $8.9 annually. The 2010 and 2011 Test Year Capital Forecasts are about 26% and 23% respectively higher than the last three years of actual experience.

    What alternatives or adjustments to the listed capital projects did Algoma Power consider to keep the 2010 and 2011 Capital Forecast closer to the historical average?

15. Ref: Exhibit 2 /Tab 4 /Schedule 2
    The 2010 forecast Capital Budget includes about $1.9 million for the "Replacement Supply to St. Joseph's Island" project. The evidence also indicates that about $.5 million was spent in 2008 for new submarine cables for St. Joseph's Island.

    When did Algoma Power first become aware that the substation structures and transformers serving St. Joseph's Island had deteriorated to the point where they needed to be replaced due to safety, environmental and reliability risks?

16. Ref: Exhibit 2 /Tab 4/ Schedule 5
    The 2011 Forecast Capital Budget includes $.415 million for IT software and $.625 for IT hardware.

    Please provide a copy of the business case, including a NPV or cost benefit analysis, which justifies this proposed expenditure.

Service Reliability

17. Ref: Exhibit 2 /Tab6 /Schedule 1
Algoma Power provided both service quality and reliability statistics for 2005-2009 as per the table below.

Year	2005	2006	2007	2007*	2008	2009	2009*	5-year Avg	5-year Avg*
SAIDI	6.32	9.34	9.35	9.29	8.04	9.87	8.03	8.58	8.20
SAIFI	2.47	3.64	3.32	2.84	2.49	3.42	2.64	3.07	2.82
CAIDI	2.56	2.57	2.82	3.27	3.23	2.88	3.04	2.81	2.93

* indicates loss of supply (transmission) outages excluded.

Algoma noted that the 2005- 2008 figures reflect revisions to those previously submitted through RRR annual filings. During the upgrades to its outage database in 2009, Algoma Power had performed an audit of previously entered data and had found some anomalies which needed cleansing.

a) Please confirm whether Algoma Power has formally filed with the Board its updated RRR numbers.
b) Please quantify, to the extent possible, the impact that Algoma Power expects its capital investments, maintenance program and operational practices will have on future actual results.

Operating Revenue

Load and Customer Forecasting

18. Ref: Exhibit 3 /Tab 2 /Schedule 2, Report titled "Weather Normalized Distribution System Load Forecast: 2010-2011" – Weather Normalization
On page 5, it states: “Algoma Power has adopted the 10 year average from 2000 to 2009 as the definition of weather normal. Our view is that a ten-year average based on the most recent ten calendar years available is a reasonable compromise that likely reflects the “average” weather experienced in recent years.”

Using a similar method to develop the weather normalized forecast for 2010 and 2011, please provide the following scenarios.

a) Instead of using the average monthly heating degree days (HDD) and cooling degree days (CDD) from 2000 to 2009, please develop the weather normalized forecast for 2010 and 2011 by using average monthly HDD and CDD from 1990 to 2009. Please calculate the variance and percent variance from the 2010 and 2011 proposed weather normalized forecast.
b) Instead of using the average monthly HDD and CDD from 2000 to 2009, please develop the weather normalized forecast for 2010 and 2011 by using a trend of monthly HDD and CDD from 2000 to 2009. Please calculate the variance and percent variance from the 2010 and 2011 proposed weather normalized forecast.

19. <u>Ref: Exhibit 3/ Tab 2 /Schedule 2, Report titled "Weather Normalized Distribution System Load Forecast: 2010-2011" – Load Forecast</u>
On page 7 it states: "For the larger use customers in the R2 class, consumption for 2010 and 2011 are estimated at an annual throughput of 41.2 GWh, consistent with the volume in 2009."

    a) Please confirm whether the larger use customers mentioned above are the same customers that were removed from the weather sensitive load (WSL) calculations.
    b) Please provide the basis of the above estimate for the larger use customers in R2 class for 2010 and 2011.

20. <u>Ref: Exhibit 3/ Tab 2/ Schedule 2, Report titled "Weather Normalized Distribution System Load Forecast: 2010-2011" – Load Forecast</u>
Referring to page 6, Table 3 titled: "Weather Corrected WSL kWh, Algoma Power", please provide the period of each year the "Weather Normal" was calculated.

21. <u>Ref: Exhibit 3/ Tab 2/ Schedule 2, Report titled "Weather Normalized Distribution System Load Forecast: 2010-2011" – Load Forecast</u>
Referring to page 7, Table 5 titled: 10-yr (2000-2009) Weather Normal kWh Throughput, Algoma Power",

    a) Please confirm whether the load listed under column R2 included non-WSL.
    b) If the answer in (a) is "yes", please provide a breakdown for WSL and non-WSL for R2 class.
    c) Please provide detail calculations of how the total WSL kWh allocated to each individual classes and ensure the allocated WSL kWh is equal to the total WSL kWh.

22. <u>Ref: Exhibit 3/ Tab 2/ Schedule 2, Report titled "Weather Normalized Distribution System Load Forecast: 2010-2011" – Load Forecast Methodology</u>
On page 4, it states: "Using the data discussed, a multiple regression analysis was used to develop an equation describing the relationship between monthly actual WSL kWh and the explanatory variables. The resulting equation, estimated using the 50 observations from 2005:11-2009:12 is displayed in Table 1 …"

    Table 1 includes the following variables: HDD, CDD, PeakDays, time, and const.

    a) Please provide more detail on the purpose and use of the variable "time".
    b) Please explain the rationale for not using "number of customers' as an explanatory variable in the regression equation.
    c) Please prepare a load forecast for 2010 & 2011 using the regression equation, kWh=f(Total customers, HDD, CDD, PeakDays, time) + constant. If monthly customer data is not available, please make a reasonable assumption for the purpose of completing the interrogatory.
    d) Please provide the statistical results of the above equation and update Table 7 (page 8 of the "Weather Normalized Distribution System Load Forecast: 2010-2011" report) based on the results.

e) Please provide the impact on the proposed 2010 and 2011 load and the revenue deficiency, if the load forecast based on the above regression equation is adopted.

23. Ref: Exhibit 3/ Tab 2/ Schedule 2, Report titled "Weather Normalized Distribution System Load Forecast: 2010-2011" – Customer Forecast
On page 8, it states: “Annual average customer counts are developed by averaging year-end customer counts. No new customer attachments (or customer losses) are expected in the R2 and Streelight classes. R1 and Seasonal are expected to continue grow at the long term growth rate of roughly 0.3 per cent per annum.”

Please explain how the 0.3 per cent per annum is determined.

Other Distribution Revenue

24. Ref: Exhibit 3/ Tab 3/ Schedule 1
Please explain why Algoma Power forecasts no revenue in 2010 and 2011 in account 4405 (Interest and Dividend Income).

Operating and Maintenance Expenses

25. Ref: Exhibit 4/Tab1/Schedule 1 p.1 and Exhibit 6/Tab1/Schedule1 p2
Algoma Power’s OM&A expenses are forecast to total $9,059,236 fro 2010 and $9,840,207 for 2011. The calculation of the revenue requirement for 2010 and 2011 includes OM&A expenses of $8,889,236 and $9,670,207 respectively.

a) For each of 2010 and 2011 please explain what comprises the difference between the amounts presented in Exhibit 4 and Exhibit 6.

26. Ref. Exhibit 4/ tab2/ Scedule2 p. 1
Algoma Power indicates that its OM&A expenses for 2010 and 2011 include $20,000 and $20,000 respectively in Donations.

a) Please describe the nature of these Donations?
b) Does Algoma Power have a Low Income Energy Assistance Program? If so, how much is budgeted for the Program in 2010 and 2011?

27. Exhibit 4/Tab1/ Schedule 1 p. 2-4
Vegetation Management Program expenditures are shown as $1.8, $2.2, and $2.5 million for 2009 actual, 2010 test year and 2011 test year respectively. A goal of the program is to control vegetation utilizing a 6 year cycle. Algoma Power also notes that it is managing its transition from the combined expansion/maintenance program to a fully operational 6-year vegetation maintenance cycle.

a) Please provide the Vegetation Management Program expenditures for 2007 Board-approved, 2007 actual and 2008 actual.

b) What are the Program's projected expenditures for 2012 and 2013?

28. Exhibit 4/Tab1/ Schedule 2 p. 4
Algoma Power states that "…. the business has recently transitioned from an integrated distribution and transmission business to a stand-alone distribution business. On an interim basis, API will continue to utilize the IT system of Great Lakes Power Limited's transmission business and receive support through a services agreement plus limited support from CNPI….. an implementation plan has been developed for the migration to an SAP IT system."

Please explain whether the purchase of the distribution business by FortisOntario from Great Lakes Power is either wholly or partly responsible for the need to migrate to an SAP IT system.

29. Exhibit 4/Tab 3/ Schedule 1
With respect to metering reading expense, the evidence states that the increase of $118,300 between 2007 Board-approved and 2010 Test Year is due to the manual reading that will be required until Smart Meter reading remote capabilities are implemented in 2011.

Assuming that the capabilities are implemented as planned, will this manual reading expense continue to be incurred in 2012?

30. Ref: Exhibit 4/ Tab 1/ Schedule 1 – Regulatory costs
On page 5, it states: "API is requesting a recovery of regulatory expenses in the amount of $75,000 in 2010. This amount is one third of the total forecasted regulatory costs for this Application".

Please provide the rationale for recovering the costs over a three year period.

31. Ref: Exhibit 4/ Tab 1/ Schedule 1/ Page 1 – Inflation rate
What inflation rate was used for the 2010 and 2011 OM&A forecast and what is the source document for the inflation assumptions?

32. Ref: Exhibit 4/ Tab 3/ Schedule 1 – Administration and General Expenses
On page 5, it states: "The increase in costs of $571,000 from 2007 Board Approved to 2010 Test Year is the result of the following: increase in FTE's and corresponding compensation costs associated with the split from the transmission business, an increase in FTE's as a result of bringing contracted work in house, and increased wages and employee benefit costs. Certain allocations from FortisOntario also contributed to the increase. These increases have been partially offset by the reduction in outside services employed, the elimination of cost sharing of general management salaries and expense with transmission, and the removal of Ontario Operations Allocation from Brookfield Renewable Power."

a) Please provide the amount, and explanation, of the increase contributed by allocations from FortisOntario.
b) Please provide the breakdown of the amounts mentioned above that have been reduced in 2010 and 2011 in the areas of i) outside services employed, ii) the

elimination of cost sharing of general management salaries and expense with transmission, and iii) the removal of Ontario Operations Allocation from Brookfield Renewable Power.

33. Ref: Exhibit 4/ Tab 4/ Schedule 1 – Employee Compensation
On page 1, it states: "Salary increases for 2010 and 2011 were based on market information, including adjustments for performance and economic market conditions."

Please file with the Board the market information that Algoma Power used to determine the salary increases and demonstrate how Algoma Power has used that information to determine the salary increases.

34. Ref: Exhibit 4/ Tab 4/ Schedule 3/ Page 1 – FTE
Regarding the increase of 7.86 in the non-union FTEs over the period from 2007 Actual to 2011 Test year, please identify the year that each position was or will be added and indicate whether the position is classified as managerial position or not.

Corporate Cost Allocation and Shared Services

35. Ref: Exhibit 4 /Tab 5/ Schedule 1 – Services Agreements
On page 1, it states: "Services Agreements between FortisOntario and its Board licensed affiliates have been previously filed and are due to expire in September 2010. Upon expiry, FortisOntario will enter renewed service agreements with all of its business units including API. In the interim, API and its affiliates abide by the terms of the agreements filed with the Board."

a) Please provide a copy of the aforementioned existing service agreements between FortisOntario and its Board licensed affiliates.
b) Please indicate the date by which Algoma Power will file the renewed service agreements.

36. Ref: Exhibit 4 /Tab 5 /Schedule 1 – Shared Services/Corporate Cost Allocation
On page 3, Algoma provides two tables, titled "2010 Shared Services/Corporate Cost Allocation" and "2011 Shared Services/Corporate Cost Allocation".

a) Please confirm the total cost for shared services allocated to Algoma Power is $582,000 for 2010 and $585,000 for 2011.
b) Please provide a full picture of the inter-corporate allocations/charges by completing the following table for each of 2009 actual, 2010 test year and 2011 test year.

Corporate Functions Allocated - Shared Services					
	Name of Company				
Function	From	To	% Allocation	Cost for the Service ($)	Pricing Methodology
Executive Services					
Total			100%		
Finance					
Total			100%		
Information Technology -Expenses					
Total			100%		
Information Technology -Assets					
Total			100%		
Health, Safety and Environment					
Total			100%		
Human Resources					
Total			100%		
Regulatory					
Total			100%		
Engineering Design Management for Capital Projects					
Total			100%		
Service Centre Building costs					
Total			100%		

37. Ref: Exhibit 4/ Tab 5/ Schedule 1/ Appendix A and EB-2005-0001, page 88
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 clarify whether BDR considered these principles when completing its review. If so, please provide a copy of BDR's views on the matter.
   b) If BDR did not report on these principles, please explain whether the costs allocated to Algoma Power are justified by these principles. Please provide an explanation for each of the principles in turn.

Cost of Capital and Capital Structure

38. Ref: Exhibit 5/ Tab 1/ Schedule 1 p.2
    Algoma Power, while indicating that it has used a return on equity (ROE) of 9.85% in the 2010 and 2011 Test Years as established by the Board for cost of service applications with a May 1, 2010 implementation, notes that the ROE will be updated in accordance with Board guidelines.

    Please confirm that the Board mentioned guidelines are to be found in the *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* [EB-2009-0084] dated December 11, 2009.

39. Ref: Exhibit 5 /Tab 1 /Schedule 1 p.2
    Algoma Power indicates that it has engaged CIBC World Markets to assist with the private placement of approximately $45-$50 million in senior unsecured third party debt (to replace the existing affiliated debt) which it expects to be completed by the end of 2010.

    What is Algoma Power's best estimate as to when this arrangement will be completed?

40. Ref: Exhibit 5 Tab 1 Schedule 1 p.2-3
    Algoma Power indicates that management is contemplating a strategy to issue future debt for regulated utilities at the parent company level, i.e., FortisOntario which should result in less costly debt.

    Does Algoma Power expect this arrangement to be completed before the end of 2011?

Deferral and Variance Accounts

41. Ref: Exhibit 9/Tab 1/Schedule 5 – Regulatory Asset Accounts (Pension Expense)
    Algoma Power is requesting a new variance account for Pension expense.

    a) Please provide the justification for this request.
    b) Has Algoma Power received the actuarial assessment of costs from Mercer?
    c) Has Algoma Power filed the actuarial assessment with FSCO?
    d) If the actuarial assessment was received prior to filing this application, why has Algoma Power not used actual pension expense costs in this filing, instead of estimated assessment pension costs?
    e) What is the proposed methodology for recording pension costs into this account (cash or accrual)?
    f) Is Algoma Power aware of any regulatory precedent in support of its proposal?
    g) Please provide an estimate of the variance to be recorded in this account.
    h) What account number does Algoma Power propose to use in the USoA?
    i) What are the journal entries to be recorded?
    j) When does Algoma Power plan to ask for its disposition?
    k) How does Algoma Power plan to allocate this amount by rate class?
    l) What new or additional information is available since the June 7, 2010 filing of this application that would assist the Board in making a decision on this request?

42. Ref: Exhibit 9/Tab 1/Schedule 5 – Regulatory Asset Accounts (IFRS)
Algoma Power is seeking approval for IFRS deferral account to capture the aggregate impact on the 2011 revenue requirement resulting from any changes to the existing IFRS standards and changes in the interpretation and implementation of such standards.

The Board report EB-2008-0408 dated July 28, 2009 "*Transition to International Financial Reporting Standards*" (Appendix 2, article 8.2) states :"The Board will establish a deferral account for distributors for incremental one-time administrative costs related to the transition to IFRS. This account………is not to include…….. impacts on revenue requirements arising from changes in the timing of the recognition of expenses." In its October 2009 FAQ's, the Board established account 1508, Other Regulatory Assets, "sub-account Deferred IFRS Transition Costs" for those distributors that do not have a Board-approved amount designated for one-time administrative incremental IFRS transitions costs already included for recovery in its distribution rates. For distributors that do have a Board-approved amount designated for one-time administrative incremental IFRS transition costs already included for recovery in distribution rates, the Board established, account 1508, Other Regulatory Assets, "Sub-account IFRS Transition Costs Variance".

a) Does the Revenue Requirement for each of 2010 and 2011 include one-time or ongoing costs related to the implementation of IFRS? If so, please identify the amount, its purpose and whether it is ongoing or one-time.
b) Are Algoma Power's current rates recovering any IFRS related costs? If so, please describe the amount and their purpose.
c) Is the proposed account expected to record any costs specifically excluded in the Board report EB-2008-0408 (i.e. ongoing compliance costs or impacts on revenue requirement arising from changes in timing of the recognition of expenses)?
d) Does Algoma Power anticipate the net balance in this account to be a debit or credit and what would the net balance total?
e) When does Algoma Power plan to ask for its disposition?
f) Has Algoma Power considered the determinants that would be used to allocate the balance to rate classes?

43. Ref: Exhibit 9 /Tab 2 /Schedules 1&2
The amount requested for disposition includes Account 1525 (Miscl. Deferred Debits). The balance in this account is $.412 million plus interest and the costs recorded are those incurred by Great Lakes Power Distribution when it acquired the distribution assets from Great Lakes Power Limited. The acquisition was required under Section 71 of the OEB Act.

a) To what extent was this regulatory asset a consideration in the valuation underpinning the purchase price paid by FortisOntario when it acquired Algoma Power?
b) Does Algoma Power expect any additional section 71 related costs to be recorded in this account?
c) Please provide a breakdown for each type of cost in account 1525 requested for disposition (e.g. transfers and land registration costs $x; statutory filing costs $y etc.).
d) Please explain why Algoma Power choose "number of customers" rather than kWh as the allocator re: account 1525 (section 71 re-organization)

44. Ref: Exhibit 9/Tab 1/Schedule 1
Algoma Power is seeking the disposition and recovery in rates of the amount of $2,478,950 as set out in Exhibit 9 Tab 2 Schedule 1 p.1. The included accounts are 1580, 1584, 1586, 1588, 1508, 1525.

a) Please confirm that Algoma Power has complied with and correctly applied the Board's accounting policy and procedures for the calculation of the final disposition balance.
b) If Algoma Power used other practices in the calculation, please describe them, including an explanation of why they were used.
c) Has Algoma Power reviewed the Regulatory Audit & Accounting Bulletin 200901 dated October 15, 2009, and ensured that it has accounted for its account 1588 and sub-account Global Adjustment in accordance with this Bulletin?
d) Has Algoma Power considered recovering account 1588 sub account global adjustment only from non Regulated Price Plan customers? If not, please explain why it hasn't.

Cost Allocation and Rate Design

45. Ref: Exhibit 7/ Tab 1/ Schedule 1/ Page 4 – Cost Allocation Model
Algoma provided Sheet O1 of the cost allocation model.

a) Please confirm whether the results of Sheet O1 reflect the revenue to cost ratio for the 2010 Test year.
b) Please explain how the Distribution Revenue is calculated.
c) In Sheet O1 the Total Revenue Requirement is $17,689,706; however the total 2010 Service Revenue Requirement listed on Exhibit 6 Tab 1 Schedule 2 Page 1 is $18,928,065. Please explain the difference.

46. Ref: Exhibit 7/ Tab 1/ Schedule 2 – Cost Allocation Study
On page 11 of the study, it states: "The API-2010 ratios reflect the 2010 forecast throughput by class, allocated costs and revenues at proposed rates. Table 8 represents the revenue responsibility (i.e. allocation of the total revenue requirement to the rate classes). This revenue responsibility is presented in both dollar and percentage terms." ITable 8 shows a total revenue of $17,810,531; however the total 2010 Service Revenue Requirement listed on Exhibit 6/ Tab 1/ Schedule 2/ Page 1 is $18,928,065.

Please explain the reason(s) for the difference.

47. Ref: Exhibit 7/ Tab 1/ Schedule 1/ Page 4 – Cost Allocation Model
Please provide an alternative calculation which uses the most recent approved distribution rates and the forecast of billing quantities in the test year, prorated upwards or downwards (as applicable) to match the 2010 proposed revenue requirement and file the model in excel format.

48. Ref: Exhibit 8/ Tab 2/ Schedule 1/ Page 1 – Fixed and Variable Proportion
Please compare the proposed Monthly Fixed Charge for all the classes to the Cost Allocation Model, API 2010 CA Model_20100601, and identify the class that exceeds the maximum level of the Monthly Fixed charge as stated in Sheet O2 of the model.

49. Ref: Exhibit 8/Tab 3/ Schedule 1 p. 4-5
With respect to Retail Transmission Service Rates, Algoma Power provided an analysis in the evidence and on this basis proposes "…to leave its existing Retail Transmission – Network Service Rate unchanged and proposes to reduce its Retail Transmission – Connection Service Rate by 6.98% uniformly across all classes to compensate for the accrual of over-collection." The rates presented in Table 3 (Exhibit 8 Tab 3 Schedule 1 p.5) show the Network Service Rate decreasing and the Connection Service Rate unchanged for 2010.

Please explain this discrepancy.

Loss Factors

50. Ref: Exhibit 8 /Tab 5 /Schedule 1 p.2-3
The evidence at Exhibit 8 Tab 5 Schedule 1 p.2 provides a calculation of historic Distribution Loss Factors (DLF) and Total Loss Factors (TLF). The historic values for the Supply Facility Loss Factor (SFLF) are obtained by dividing the kWh values provided in Lines A_1 and A_2 (i.e. calculation A_1/A_2), compute to 1.0045, 1.0099, 1.0095, 1.0059 and 1.0097 respectively for the years 2005 to 2009.
Algoma Power explains the reason its factors are greater than the Board's 5% threshold is because it serves a very large geographic area of approximately 14,200 square kilometers with 1845 kilometers of line servicing 11,720 customers. Algoma Power concludes that, as such with its very low customer density, its loss factor will exceed 5%.

a) Does Algoma Power know of any other material reasons in addition to the aforementioned?
b) Does Algoma Power have a plan to reduce its losses? If so, please provide the plan. If not, please explain why not.

51. Ref: Exhibit 8 /Tab 5/ Schedule 1 p.2-3
The evidence at Exhibit 8 Tab 5 Schedule 1 p.3 provides a calculation of the proposed TLF and underlying DLF.

Given the enduring line losses and the lowering impact of both the ongoing conductor replacement program and the voltage conversions, please explain the reason for proposing the average of 2007 to 2009 actual values for DLF and TLF rather than the lower actual value for 2009.

Smart Meters

52. Ref: Exhibit 10/ Tab 1/ Schedule 1
Algoma Power is seeking approval for a Smart Meter funding adder of $1.00 per metered customer, effective July 1, 2010. There is no funding adder currently in place. Per the *Smart Meter Funding and Cost Recovery G-2008-0002* (dated October 22, 2008) guideline pages 9-10, utilities seeking a funding adder are to provide certain information in their application. Particulars include:
    - Evidence that distributor is authorized to conduct smart meter activities in accordance with applicable law
    - the estimated number of meters to be installed in the rate test year
    - the actual or estimated costs per installed meter and in total
    - statement as to whether the distributor has purchased, or expects to purchase, smart meters or advanced metering infrastructure (AMI) whose functionality exceeds the minimum functionality adopted in O. Reg. 425/06, and an estimate of those costs
    - a statement as to whether the distributor has incurred, or expects to incur, costs associated with functions for which the SME has the exclusive authority to carry out pursuant to O. Reg. 393/07, and an estimate of those costs

    Please confirm that Algoma Power’s evidence includes the aforementioned information.