**<u>Question #1</u>**

**Reference:** Exhibit 1, Tab 1, Schedule 2
Exhibit 1, Tab 1, Schedule 5
EB-2009-0423, OEB's Letter of April 15, 2010, page 2 and
Appendix B

a) Why does Algoma consider July 1, 2010 to be an appropriate effective date for its proposed 2010 rates?

b) Would it be appropriate, as part of Algoma's proposed Phase 2, to:
   - update the ROE and other cost capital elements for 2011 based on the values that will be established by the Board for 2011, and
   - Update the RTSR rates to reflect HON's 2011 rates?

c) Please indicate where in the Application Algoma has specifically addressed and provided an analysis of the benefits and ratemaking implications of aligning its proposed rate year with January 1st as of 2011.

d) If not done so as part of the Application, please provide the required analysis as per the Board's April 2010 Letter.

---

**RESPONSE:**

a) In Algoma's view, the Board in its Decision and Order in the matter of EB-2007-0744 established certain expectations for the Applicant. The following is a listing of the more salient expectations and is not intended to be an exhaustive listing:

   a. The Tariff of Rates and Charges arising from EB-2007-0744 was, at the time of the Rate Order, made interim as of May 1, 2009. API interprets this as an expectation that a new cost of service would have been anticipated effective as early as May 1, 2009.
   b. With respect to load forecasting, weather normalization and cost allocation, the Board expressed an expectation that the Applicant would address these matters in it next cost of service rate application.
   c. The Board approved the mitigation for Seasonal customers and expressed an expectation that the applicant, in its next application, present a planned approach to ensure balances are cleared.

   API remains cognizant of the Board's expectations arising from EB-2007-0744, however it could not have filed its application any sooner than it did, as described in the response to Board staff Interrogatory No. 2. API was acquired by FortisOntario in October of 2009, at which time API started to diligently prepare its cost of service distribution rate application. Prior to this acquisition, API's predecessor had not commenced preparation of an application or supporting evidence for a 2010 cost of service filing. So, in addition to transitioning to new ownership, a significant amount of effort was required to prepare the rate application.

b) Algoma's preference is expressed in Exhibit 1, Tab 1, Schedule 2. Phase 1 of the proceeding would approve API's 2010 and 2011 revenue requirements; determine the average rate increase for distributors in 2010; design the 2010 rates; implement the 2010 rates effective July 1, 2010; and make API's 2010 rates interim effective January 1, 2011. Phase 2 of the proceeding would determine the average rate increase for distributors in 2011; design the 2011 rates; and implement of the 2011 rates effective January 1, 2011.

c) An analysis of the benefits and ratemaking implications of aligning its proposed rate year with January 1st as of 2011 is not specifically addressed in the Application.

d) Please refer to SEC Interrogatory No. 2 part (c).

**<u>Question #2</u>**

**Reference:** Exhibit 1, Tab 1, Schedule 13, page 1
Exhibit 1, Tab 3, Schedule 3

a) Please explain the relationship between Algoma Power Inc. and 1228158 Ontario Limited. Please confirm that that there are no affiliate transactions anticipated between these two entities in 2010 and 2011.

---

**RESPONSE:**

1228158 Ontario Limited is a wholly owned subsidiary of Algoma Power Inc. There are no affiliate transactions anticipated between the two entities in 2010 and 2011.

## Question #3

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

a) Please confirm what year the 6.3 customers per kilometre of line is based on and provide the associated customer count and line kilometres.

b) Please provide the forecasted customer count and distribution line kilometres for 2010 and 2011.

---

**RESPONSE:**

a) The 6.3 customers per kilometre of line is based on the following formula:

Average customer density per kilometers of distribution line
= Average number of customers / Year end number of distribution circuit kilometers

The basis for 6.3 customers per kilometer is fiscal 2009 in which the average number of customers was 11,720 and the year end number of distribution circuit kilometers was 1,845.

b) API customer forecasts for 2010 and 2011 are provided in Exhibit 3, Tab 2, Schedule 1, Table 1. API expects to add 7 km of line in 2010, for a total of 1,852 distribution line kilometres. API is not currently forecasting any change in total distribution line kilometres in 2011.

**Question #4**

**Reference:** Exhibit 1, Tab 2, Schedule 1, page 10

a) Please provide schedules that set out the calculation (by class) for the 2010 and 2011 Total Operating Revenues. Please show the volumes and rates used for each class.

---

**RESPONSE:**

Exhibit 1, Tab 2, Schedule 1, Table 1E – Operating Revenue Summary found on page 10 is a reproduction of the Distribution Revenue line found in Exhibit 6, Tab 1, Schedule 1, the Revenue Deficiency/Sufficiency. These amounts for 2010 and 2011 are derived from Algoma's monthly revenue forecast. The rates used in the determination are those approved by the Board in EB-2007-0744, Algoma's current Tariff of Rates and Charges. The customers and volumes are the normalized values determined in Exhibit 3, Tab 2, Schedule 1.

The following is a detailed derivation of the forecast amounts. Note that there is a minor discrepancy in the 2010 forecast amount. Exhibit 1, Tab 2, Schedule 1, Table 1E – Operating Revenue Summary and Exhibit 6, Tab 1, Schedule 1, the Revenue Deficiency/Sufficiency state $17,619,307 while the information following calculates $17,619,320, a difference of $13. This has occurred due to rounding.

## Algoma 2010 Revenue Forecast

| Rate Category | Total | Jan | Feb | Mar | Apr | May | June | July | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Residential - R1** | | | | | | | | | | | | | |
| Monthly Service Charge | 1,962,238 | 163,260 | 163,300 | 163,341 | 163,382 | 163,443 | 163,505 | 163,566 | 163,607 | 163,647 | 163,688 | 163,729 | 163,770 |
| Distribution Charge | 3,006,707 | 334,990 | 299,396 | 295,230 | 239,831 | 223,047 | 200,694 | 210,105 | 208,191 | 198,440 | 233,102 | 254,936 | 308,746 |
| Subtotal | 4,968,945 | 498,249 | 462,696 | 458,571 | 403,213 | 386,490 | 364,199 | 373,671 | 371,798 | 362,088 | 396,790 | 418,665 | 472,516 |
| **Residential - R2** | | | | | | | | | | | | | |
| Monthly Service Charge | 343,365 | 28,614 | 28,614 | 28,614 | 28,614 | 28,614 | 28,614 | 28,614 | 28,614 | 28,614 | 28,614 | 28,614 | 28,614 |
| Distribution Charge | 371,029 | 40,623 | 38,797 | 38,258 | 30,994 | 27,240 | 24,774 | 23,820 | 24,261 | 24,729 | 28,035 | 32,298 | 37,200 |
| Transformation Ownership Credit | (51,942) | (5,687) | (5,431) | (5,356) | (4,339) | (3,813) | (3,468) | (3,335) | (3,396) | (3,462) | (3,925) | (4,522) | (5,208) |
| Subtotal | 662,452 | 63,550 | 61,979 | 61,516 | 55,269 | 52,041 | 49,919 | 49,099 | 49,478 | 49,881 | 52,724 | 56,391 | 60,606 |
| **Seasonal** | | | | | | | | | | | | | |
| Monthly Service Charge | 1,050,960 | 87,432 | 87,432 | 87,432 | 87,480 | 87,528 | 87,576 | 87,624 | 87,672 | 87,696 | 87,696 | 87,696 | 87,696 |
| Distribution Charge | 872,258 | 97,176 | 86,829 | 85,600 | 69,558 | 64,701 | 58,227 | 60,968 | 60,431 | 57,602 | 67,646 | 73,964 | 89,554 |
| Subtotal | 1,923,218 | 184,608 | 174,261 | 173,032 | 157,038 | 152,229 | 145,803 | 148,592 | 148,103 | 145,298 | 155,342 | 161,660 | 177,250 |
| **Street Lights** | | | | | | | | | | | | | |
| Monthly Service Charge | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Distribution Charge | 39,283 | 4,383 | 3,917 | 3,861 | 3,136 | 2,915 | 2,622 | 2,744 | 2,718 | 2,590 | 3,042 | 3,326 | 4,027 |
| Subtotal | 39,283 | 4,383 | 3,917 | 3,861 | 3,136 | 2,915 | 2,622 | 2,744 | 2,718 | 2,590 | 3,042 | 3,326 | 4,027 |
| **Total Electricity Distribution Revenue** | | | | | | | | | | | | | |
| Monthly Service Charge | 3,356,563 | 279,305 | 279,346 | 279,387 | 279,476 | 279,585 | 279,694 | 279,804 | 279,892 | 279,957 | 279,998 | 280,039 | 280,080 |
| Distribution Charge | 4,289,277 | 477,172 | 428,938 | 422,950 | 343,518 | 317,904 | 286,317 | 297,638 | 295,601 | 283,362 | 331,825 | 364,525 | 439,527 |
| Transformation Credit | (51,942) | (5,687) | (5,431) | (5,356) | (4,339) | (3,813) | (3,468) | (3,335) | (3,396) | (3,462) | (3,925) | (4,522) | (5,208) |
| **Distribution Revenue from Rates** | **7,593,898** | **750,791** | **702,853** | **696,981** | **618,655** | **593,675** | **562,544** | **574,106** | **572,097** | **559,857** | **607,898** | **640,042** | **714,399** |
| **Rural and Remote Rate Protection** | 8,861,844 | 738,487 | 738,487 | 738,487 | 738,487 | 738,487 | 738,487 | 738,487 | 738,487 | 738,487 | 738,487 | 738,487 | 738,487 |
| **Seasonal Deferral Account** | 820,521 | 68,377 | 68,377 | 68,377 | 68,377 | 68,377 | 68,377 | 68,377 | 68,377 | 68,377 | 68,377 | 68,377 | 68,377 |
| **Total (Including Seasonal Deferral and RRRP)** | **17,276,263** | **1,557,655** | **1,509,717** | **1,503,844** | **1,425,519** | **1,400,539** | **1,369,407** | **1,380,970** | **1,378,961** | **1,366,721** | **1,414,762** | **1,446,906** | **1,521,263** |
| | | | | | | | | | | | | | |
| **Revenue Offset** | **343,057** | | | | | | | | | | | | |
| | | | | | | | | | | | | | |
| **Total Distribution Revenue** | **17,619,320** | | | | | | | | | | | | |

## Algoma 2011 Revenue Forecast

| Rate Category | Total | Jan | Feb | Mar | Apr | May | June | July | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Residential - R1** | | | | | | | | | | | | | |
| Monthly Service Charge | 1,968,810 | 163,811 | 163,851 | 163,892 | 163,933 | 163,994 | 164,056 | 164,117 | 164,158 | 164,198 | 164,239 | 164,280 | 164,280 |
| Distribution Charge | 3,046,173 | 339,397 | 303,334 | 299,114 | 242,985 | 225,981 | 203,334 | 212,868 | 210,929 | 201,050 | 236,167 | 258,287 | 312,727 |
| Subtotal | 5,014,983 | 503,208 | 467,186 | 463,006 | 406,918 | 389,975 | 367,389 | 376,985 | 375,086 | 365,248 | 400,406 | 422,567 | 477,007 |
| **Residential - R2** | | | | | | | | | | | | | |
| Monthly Service Charge | 343,365 | 28,614 | 28,614 | 28,614 | 28,614 | 28,614 | 28,614 | 28,614 | 28,614 | 28,614 | 28,614 | 28,614 | 28,614 |
| Distribution Charge | 373,027 | 40,842 | 39,006 | 38,465 | 31,161 | 27,387 | 24,907 | 23,948 | 24,391 | 24,862 | 28,186 | 32,472 | 37,400 |
| Transformation Ownership Credit | (51,942) | (5,687) | (5,431) | (5,356) | (4,339) | (3,813) | (3,468) | (3,335) | (3,396) | (3,462) | (3,925) | (4,522) | (5,208) |
| Subtotal | 664,450 | 63,769 | 62,188 | 61,722 | 55,436 | 52,187 | 50,053 | 49,227 | 49,609 | 50,014 | 52,875 | 56,565 | 60,806 |
| **Seasonal** | | | | | | | | | | | | | |
| Monthly Service Charge | 1,054,008 | 87,696 | 87,696 | 87,696 | 87,720 | 87,768 | 87,816 | 87,864 | 87,912 | 87,960 | 87,960 | 87,960 | 87,960 |
| Distribution Charge | 883,533 | 98,443 | 87,961 | 86,715 | 70,445 | 65,526 | 58,970 | 61,746 | 61,201 | 58,352 | 68,527 | 74,927 | 90,720 |
| Subtotal | 1,937,541 | 186,139 | 175,657 | 174,411 | 158,165 | 153,294 | 146,786 | 149,610 | 149,113 | 146,312 | 156,487 | 162,887 | 178,680 |
| **Street Lights** | | | | | | | | | | | | | |
| Monthly Service Charge | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Distribution Charge | 39,283 | 4,383 | 3,917 | 3,861 | 3,136 | 2,915 | 2,622 | 2,744 | 2,718 | 2,590 | 3,042 | 3,326 | 4,027 |
| Subtotal | 39,283 | 4,383 | 3,917 | 3,861 | 3,136 | 2,915 | 2,622 | 2,744 | 2,718 | 2,590 | 3,042 | 3,326 | 4,027 |
| **Total Electricity Distribution Revenue** | | | | | | | | | | | | | |
| Monthly Service Charge | 3,366,183 | 280,120 | 280,161 | 280,202 | 280,267 | 280,376 | 280,485 | 280,595 | 280,683 | 280,772 | 280,813 | 280,854 | 280,854 |
| Distribution Charge | 4,342,016 | 483,065 | 434,218 | 428,155 | 347,727 | 321,809 | 289,833 | 301,306 | 299,240 | 286,854 | 335,922 | 369,013 | 444,875 |
| Transformation Credit | (51,942) | (5,687) | (5,431) | (5,356) | (4,339) | (3,813) | (3,468) | (3,335) | (3,396) | (3,462) | (3,925) | (4,522) | (5,208) |
| **Distribution Revenue from Rates** | **7,656,257** | **757,498** | **708,948** | **703,001** | **623,655** | **598,372** | **566,850** | **578,566** | **576,527** | **564,165** | **612,810** | **645,346** | **720,521** |
| **Rural and Remote Rate Protection** | 8,861,844 | 738,487 | 738,487 | 738,487 | 738,487 | 738,487 | 738,487 | 738,487 | 738,487 | 738,487 | 738,487 | 738,487 | 738,487 |
| **Seasonal Deferral Account** | 820,521 | 68,377 | 68,377 | 68,377 | 68,377 | 68,377 | 68,377 | 68,377 | 68,377 | 68,377 | 68,377 | 68,377 | 68,377 |
| **Total (Including Seasonal Deferral and RRRP)** | **17,338,622** | **1,564,362** | **1,515,811** | **1,509,865** | **1,430,518** | **1,405,236** | **1,373,714** | **1,385,430** | **1,383,391** | **1,371,028** | **1,419,674** | **1,452,209** | **1,527,385** |
| | | | | | | | | | | | | | |
| **Revenue Offset** | **370,082** | | | | | | | | | | | | |
| | | | | | | | | | | | | | |
| **Total Distribution Revenue** | **17,708,704** | | | | | | | | | | | | |

**Algoma Power Inc.**
**Monthly Fixed and Variable Tariff**

| Monthly Rates and Charges | Metric | Current | Forecast |
|---|---|---|---|
| **Residential - R1** | | | |
| Monthly Service Charge | $ | 20.41 | 20.41 |
| Smart Meter Rate Adder | $ | - | - |
| Distribution Volumetric Rate | $/kWh | 0.0287 | 0.0287 |
| | | | |
| **Residential - R2** | | | |
| Monthly Service Charge | $ | 596.12 | 596.12 |
| Distribution Volumetric Rate | $/kW | 2.4549 | 2.4549 |
| | | | |
| **Seasonal** | | | |
| Monthly Service Charge | $ | 24.00 | 24.00 |
| Distribution Volumetric Rate | $/kWh | 0.0700 | 0.0700 |
| | | | |
| **Street Lighting** | | | |
| Monthly Service Charge | $ | - | - |
| Distribution Volumetric Rate | $/kWh | 0.0496 | 0.0496 |
| | | | |
| **Loss Factor** | | | |
| Total Loss Factor | | 1.1025 | 1.1025 |
| | | | |
| Transformer Ownership Credit | | (0.60) | (0.60) |

## Algoma Load and Customer Forecast Information

| | 2007 Forecast | 2007 Actual | 2008 | 2009 Actual | 2010 Test Year | 2011 Test Year |
|---|---|---|---|---|---|---|
| **R1** | | | | | | |
| Number of Customers | 7,740 | 7,815 | 7,923 | 7,997 | 8,024 | 8,049 |
| Change in Customer Count | | | 109 | 74 | 27 | 25 |
| Kilowatt-hours | 104,428,306 | 100,674,579 | 103,691,076 | 103,761,012 | | |
| Weather Normalized Kilowatt-hours | | | | 103,317,932 | 104,754,767 | 106,119,297 |
| Average per Customer - kWh | 13,492 | 12,883 | 13,087 | 12,975 | | |
| Normalized Average per Customer - kWh | | | | 12,920 | 13,055 | 13,184 |
| **Seasonal** | | | | | | |
| Number of Customers | 3,707 | 3,718 | 3,688 | 3,643 | 3,654 | 3,665 |
| Change in Customer Count | | | (30) | (45) | 11 | 11 |
| Kilowatt-hours | 11,746,043 | 11,665,351 | 11,591,418 | 12,341,792 | | |
| Weather Normalized Kilowatt-hours | | | | 12,289,090 | 12,459,994 | 12,622,297 |
| Average per Customer - kWh | 3,169 | 3,138 | 3,143 | 3,388 | | |
| Normalized Average per Customer - kWh | | | | 3,373 | 3,410 | 3,444 |
| **Residential - R2** | | | | | | |
| Number of Customers | 47 | 47 | 48 | 48 | 48 | 48 |
| Kilowatt-hours | 50,139,889 | 75,340,938 | 66,017,652 | 69,931,763 | | |
| Kilowatts | 197,392 | 191,492 | 159,280 | 150,499 | | |
| Weather Normalized Kilowatt-hours | | | | 69,808,980 | 70,228,773 | 70,606,900 |
| Weather Normalized Kilowatts | | | | 150,235 | 151,138 | 151,952 |
| Average per Customer - kWh | 1,066,806 | 1,602,999 | 1,375,368 | 1,456,912 | | |
| Average per Customer - kW | 4,200 | 4,074 | 3,318 | 3,135 | | |
| Normalized Average per Customer - kWh | | | | 1,454,354 | 1,463,099 | 1,470,977 |
| Normalized Average per Customer - kW | | | | 3,130 | 3,149 | 3,166 |
| **Street Light** | | | | | | |
| Number of Customers | 99 | 32 | 32 | 32 | 32 | 32 |
| Kilowatt-hours | 1,010,306 | 816,298 | 791,996 | 791,996 | 791,996 | 791,996 |
| Kilowatts | | | 2,304 | 2,304 | 2,304 | 2,304 |
| **Totals** | | | | | | |
| Number of Customers | 11,593 | 11,611 | 11,691 | 11,720 | 11,758 | 11,794 |
| Kilowatt-hours | 167,324,544 | 188,497,166 | 182,092,142 | 186,826,563 | | |
| Kilowatts | 197,392 | 191,492 | 161,584 | 152,803 | | |
| Weather Normal Kilowatt-hours | | | | 186,207,998 | 188,235,530 | 190,140,490 |
| Weather Normal Kilowatts | | | | 152,539 | 153,442 | 154,256 |

**<u>Question #5</u>**

**Reference:** Exhibit 1, Tab 2, Schedule 3

a) Is it Algoma's expectation that the update to the amortization rates proposed for 2011 will be considered as part of Phase 2 of the current proceeding for incorporation into the approved 2011 rates? If not, what is Algoma's expectation as to when the revised amortization rates will be reviewed and the 2011 rates adjusted accordingly.

b) Please explain why it is not feasible to consider the changes in amortization rates in Phase 1 of the current proceeding.

c) What is Algoma's capitalization rate for 2009 based on current practice? What would the rate be for 2010 and 2011?

d) Does the proposed overhead capitalization policy adhere to the current expectation regarding IFRS requirements? If yes, what is the basis for this conclusion?

e) Please provide the page reference for Board Decision EB-2008-0222 where the methodology is specifically addressed and approved by the Board.

---

**RESPONSE:**

a) See response to OEB #8.

b) See response to OEB #8.

c) API did not capitalize overhead in 2009.

d) The IASB's Rate Regulated Activities project deals indirectly with the capitalization of overhead. No decision was made as to whether regulatory assets and liabilities can be recognized under IFRS. A final standard, if any, is not anticipated until the latter half of 2011.

e) The Board Decision (EB-2008-0222) approved CNPI's rate base, including the calculation thereof, and capital expenditures. The capitalization of overhead policy is included the calculation of rate base. In writing the decisions, the Board did not specifically address all issues and policies.

**Question #6**

**Reference:** Exhibit 2, Tab 1, Schedule 1, Appendix A, page 1

a) Reference is made to a GLPT-owned 44 kV circuit which supplies Algoma.
- Please confirm that, despite the voltage, this line is considered part of GLPL's transmission facilities.
- Please explain why this line was not included in the distribution facilities purchased by CNPI.

---

**RESPONSE:**

The 44kV line referenced is owned and operated by Great Lakes Power Transmission LP. This line was designated a Transmission asset by the Ontario Energy Board in its GLPL transmission rates decision RP-2001-0035/EB-2001-0385 issued in December 2001. Accordingly, as a transmission asset it was not associated with the acquisition by FortisOntario.

**<u>Question #7</u>**

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

a) Why is there no contributed capital recorded?
- Have there been no instances in the past (or projected for 2010 & 2011) where a capital contribution was required for a new customer connection?
- Have there been no Roadway Relocations undertaken at the behest of municipalities or road authorities?

---

**RESPONSE:**

a) API applies the methodology set out in the Distribution System Code for quantifying and recovering capital contributions. For road relocations, API recovers 50% of labour cost from the road authority in accordance with the *Public Service Works on Highways Act.*

**<u>Question #8</u>**

**Reference:** Exhibit 2, Tab 3, Schedule 1

a) Please provide a schedule that sets out Algoma's actual 2009 billing determinants for Hydro One Networks' Transmission Network charges. Using Hydro One Networks' approved 2010 rate for Network charges, please include in the same schedule the charges from Hydro One Networks based on 2009 billings determinants and 2010 rates.

b) Please provide a schedule that sets out Algoma's actual 2009 billing determinants for Hydro One Networks' Connection charges. Using Hydro One Networks' approved 2010 rate for Connection charges, please include in the same schedule the charges from Hydro One Networks based on 2009 billings determinants and 2010 rates.

c) Please provide the source of the 2010 and 2011 cost of power rates (e.g., $0.06697/kWh for 2010).

d) What proportion of Algoma's sales for 2009 were to RPP vs. non-RPP customers?

---

**RESPONSE:**

a) See the table below

| Network Service Charge | | | |
|---|---|---|---|
| **Month** | **Billing Determinant** | **Charges at 2009 UTR** | **Charges at 2010 UTR** |
| **January** | 40,250 | 103,443 | 119,543 |
| **February** | 37,690 | 96,863 | 111,939 |
| **March** | 37,220 | 95,655 | 110,543 |
| **April** | 33,518 | 86,141 | 99,548 |
| **May** | 22,705 | 58,352 | 67,434 |
| **June** | 29,639 | 76,172 | 88,028 |
| **July** | 23,089 | 59,339 | 68,575 |
| **August** | 24,240 | 62,297 | 71,993 |
| **September** | 30,052 | 77,233 | 89,254 |
| **October** | 35,227 | 90,533 | 104,624 |
| **November** | 31,132 | 80,010 | 92,463 |
| **December** | 38,088 | 97,885 | 113,120 |

b) See the tables below

| Line Connection Service Charge | | | |
|---|---|---|---|
| **Month** | **Billing Determinant** | **Charges at 2009 UTR** | **Charges at 2010 UTR** |
| **January** | 18,039 | 12,627 | 13,168 |
| **February** | 17,245 | 12,072 | 12,589 |
| **March** | 17,978 | 12,585 | 13,124 |
| **April** | 23,342 | 16,339 | 17,040 |
| **May** | 13,064 | 9,145 | 9,537 |
| **June** | 20,604 | 14,423 | 15,041 |
| **July** | 11,735 | 8,215 | 8,567 |
| **August** | 12,643 | 8,850 | 9,229 |
| **September** | 20,982 | 14,687 | 15,317 |
| **October** | 24,108 | 16,876 | 17,599 |
| **November** | 15,204 | 10,643 | 11,099 |
| **December** | 18,368 | 12,858 | 13,409 |

| Transformation Connection Service Charge | | | |
|---|---|---|---|
| **Month** | **Billing Determinant** | **Charges at 2009 UTR** | **Charges at 2010 UTR** |
| **January** | 43,058 | 69,754 | 73,629 |
| **February** | 39,936 | 64,696 | 68,291 |
| **March** | 41,205 | 66,752 | 70,461 |
| **April** | 38,600 | 62,532 | 66,006 |
| **May** | 28,050 | 45,441 | 47,966 |
| **June** | 34,633 | 56,105 | 59,222 |
| **July** | 24,397 | 39,523 | 41,719 |
| **August** | 26,556 | 43,021 | 45,411 |
| **September** | 33,283 | 53,919 | 56,914 |
| **October** | 38,291 | 62,031 | 65,477 |
| **November** | 31,531 | 51,080 | 53,918 |
| **December** | 39,098 | 63,339 | 66,857 |

c) Please refer to the response provided in Board Staff Interrogatory No. 12.

d) In 2009, approximately 25% of Algoma's commodity sales were to Non-RPP consumers.

**<u>Question #9</u>**

**Reference:** Exhibit 2, Tab 4, Schedule 2, pages 7, 10, 14 and 17

a) Please provide a schedule that for 2008-2011 shows the number of transformers required annually for new services versus replacement/load growth.

b) Please indicate where in the Application the offsetting reduction in 2011 OM&A expense for reduced Nodwell rental costs is addressed.

---

**RESPONSE:**

a) API tracks its annual transformer purchases in the two categories described in Exhibit 2, Tab 4, Schedule 2. The actual number of transformers purchased in each category is also listed in the project descriptions for transformers for 2008 and 2009. The table below provides the forecasted number of transformers required in these same categories for 2010-2011. API's work management does not provide reporting to the level of granularity required to split the inventory of transformers into new services versus replacement/load growth as requested.

| | 2010 (forecast) | 2011 (forecast) |
|---|---|---|
| Inventory | 45 | 45 |
| Project-Specific Replacement | 215 | 60 |
| **Total** | **260** | **105** |

b) There is no offsetting expense reduction in 2011 OM&A because there are no OM&A expenses in 2010 related to the rental of the Nodwell. All of the rental costs were capitalized as the work activity associated with the rental was to install or replace poles and associated hardware.

**<u>Question #10</u>**

**Reference:** Exhibit 2, Tab 4, Schedule 5
Exhibit 2, Tab 4, Schedule 5, Appendix A

a) Please provide a schedule that sets out all of Algoma's spending on IT (OM&A and Capital) for 2010 and 2011. Please identify in the schedule the cost of the IT Services Agreement (Appendix A, page 1).

b) What is annualized revenue requirement impact of the capital spending required in 2010 and 2011 to migrate from Algoma's legacy system to CNPI's CIS and ERP SAP system?

---

**RESPONSE:**

a) The following schedule sets out API's spending on IT (OM&A and Capital) for 2010 and 2011:

| **API IT COSTS** | **2010** | **2011** |
|---|---|---|
| OM&A | 289,000 | 414,000 |
| Capital | 59,043 | 1,486,248 |

The OM&A costs associated with the IT Services Agreement represent approximately $135,000 per year in 2010 and 2011. Increased OM&A in 2011 compared with 2010 is primarily the result of an increase of approximately $118,000 for additional IT expenditures related to licensing and maintenance fees for SAP, infrastructure, communications and other software.

b) The migration from API's legacy system to CNPI's CIS and ERP SAP system is scheduled to take place in 2011, therefore there is no impact on the 2010 revenue requirement. The capital additions for the SAP Migration amounts to $783,469 plus net capital allocation of $601,022.

The impact on the 2011 revenue requirement is an increase of $37,555. The calculation is as follows:

| | |
|---|---|
| Average Rate Base | $653,072 |
| Requested rate of Return | 7.31% |
| | $ 47,740 |
| Depreciation | 78,347 |
| Income Taxes | (88,532) |
| | $ 37,555 |

## Question #11

**Reference:** Exhibit 2, Tab 5, Schedule 1

a) Please extend the table on page 6 to include 2008 and 2009.

b) Please discuss the implications of "stretching out" the right of way expansion project into 2012 so as to levelize capital spending over the 2010-2012 period.

c) What other capital programs could be re-scheduled over the 2010-2012 period so as to levelize annual spending?

d) How has the introduction of HST been factored into the capital spending projections for 2010-2011?

e) What was the amount of PST included in the 2008 and 2009 capital spending?

---

**RESPONSE:**

a) See table below.

<table>
<tr><th>Category</th><th>2008</th><th>2009</th><th>2010</th><th>2011</th><th>2012</th></tr>
<tr><td>Demand Work</td><td>$1,267,232</td><td>$1,660,717</td><td>$2,033,187</td><td>$1,710,372</td><td>$1,733,833</td></tr>
<tr><td>Right of Way Expansion</td><td>$2,897,574</td><td>$1,620,024</td><td>$2,047,857</td><td>$2,191,257</td><td>$220,478</td></tr>
<tr><td>Conductor Replacement</td><td>$2,255,252</td><td>$4,107,674</td><td>$3,867,839</td><td>$4,078,021</td><td>$4,133,958</td></tr>
<tr><td>Sub-Transmission / Substation</td><td>$1,761,575</td><td>$271,475</td><td>$1,752,144</td><td>-</td><td>$2,315,016</td></tr>
<tr><td>Other Replacements and System Improvements</td><td>$460,917</td><td>$716,486</td><td>$971,661</td><td>$620,947</td><td>$479,539</td></tr>
<tr><td>Transportation and Work Equipment</td><td>$112,347</td><td>$570,701</td><td>$323,346</td><td>$625,297</td><td>$468,515</td></tr>
<tr><td>Buildings and Yards, Land Rights</td><td rowspan="4">$333,191*</td><td rowspan="4">$435,613*</td><td>$267,299</td><td>$76,123</td><td>$77,167</td></tr>
<tr><td>IT Hardware and Software</td><td>$53,891</td><td>$1,350,314</td><td>$55,119</td></tr>
<tr><td>Business Systems and SCADA</td><td>-</td><td>$135,934</td><td>$110,239</td></tr>
<tr><td>Small Tools and Office Equipment</td><td>$53,891</td><td>$81,560</td><td>$55,119</td></tr>
<tr><td>Total</td><td>$9,088,088</td><td>$9,382,690</td><td>$11,371,114</td><td>$10,869,825</td><td>$9,648,983</td></tr>
</table>

* From an asset management/project category perspective, prior to 2010 these categories included a large number of small projects that were related to both transmission and distribution divisions. Appropriate accounting entries were made for individual accounts, however API has not updated past spending by asset management category for these categories.

b) If the program were “stretched out” to 2012 the maintenance cycle would be extended and efficiencies created by conducting the expansion program concurrently with the maintenance program as explained in Exhibit 2, Tab 4 Schedule 1, pgs 9 -10, would be reduced. Issues related to extending cycles would be encountered such as vegetation growing into unsafe clearances to electrical equipment, higher volume of vegetation material to be removed; decreases in reliability and accessibility, which are further explained in Exhibit 4 Tab 1 Schedule 1 Appendix B, pg 4. As well, by changing the plan established the program would lose synergies associated with coordination of ROW expansion and conductor replacement.

c) Please refer to API’s response to Board staff interrogatory #14.

d) Please refer to API’s response to Board staff interrogatory #5.

e) API did not track the amount of PST included in the 2008 and 2009 capital spending, so it is unable to determine the amounts.

**Question #12**

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

a) Tables 1 and 2 do not include any actual revenues or throughput values for Seasonal customers for 2007 or 2008. Please provide or fully explain why the information is not available.

---

**RESPONSE:**

The throughput volumes associated with the Seasonal Customer class for 2007 and 2008 are provided in Exhibit 3, Tab 2, Schedule 1, page 1 in Table 1 and are as follows:

- 2007 11,665,351 kWh
- 2008 11,591,418 kWh

As discussed fully in Exhibit 3, Tab 1, Schedule 1, the 2007 Board Approved revenues were established on the premise of the re-classified customer classes while actual billing and record keeping were maintained and recorded using the conventional customer classes until the implementation of EB-2007-0744 in January 2009 with new rates made effective September 2007. As discussed on pages 1 & 2 of Exhibit 3, Tab 2, Schedule 1 there were many contributors that rendered a meaningful year-over-year variance analysis of distribution revenues impractical.

The recorded values for distribution revenue from the Seasonal customers are as follows:

- 2007 $1,832,966
- 2008 $1,592,743

## Question #13

**Reference:** Exhibit 3, Tab 2, Schedule 1

a) Please outline the information a Seasonal customer must provide in order to be re-classified as Residential-R1.

---

**RESPONSE:**

Before re-classifying an existing Seasonal class customer to the Residential – R1 class, API's customer service representative will confirm that customer's eligibility for the Residential – R1 class. Confirmation normally includes the following:

- Confirmation that the billing address is the same as the address appearing on the customer's Driver's Licence or other relevant documentation such as a credit card statement.
- The customer is eligible to vote in Municipal, Provincial or Federal elections and is enumerated for these purposes at the billing address.
- The customer lives at the billing address for at least 4 days of the week, during at least 8 months of the year.

**<u>Question #14</u>**

**Reference:** Exhibit 3, Tab 2, Schedule 2

a) Please provide the current status with respect to the potential new customer discussed on page 3.

b) Please confirm the rates (and resulting revenues) shown in Tables 1 and 2:
   - Do not include a smart meter rate adder
   - Have not been reduced to account for customers owning their own transformers.

c) The discussion regarding Tables 1 and 2 states that the volumetric rates have been uplifted to simulate recovery of the RRRP.
   - Please explain why/how this adjustment was made and why it was applied to the variable rates.
   - Please also explain to which customer classes the adjustment was applied and why.

d) Please reconcile the 2010 and 2011 Distribution Revenues at current rates reported in Tables 1 and 2 with the Distribution Revenues at current rates reported in Exhibit 1, Tab 2, Exhibit 5 (Revenue Requirement Work Form) – pages 4 and 7.

---

**RESPONSE:**

a) On July 20, 2010, API entered into a connection cost agreement with this customer, with a tentative in-service date of January 15, 2011.

b) API confirms that the rates and resulting revenues shown in Tables 1 and 2 do not include a smart meter adder and have not been reduced to account for customers owning their own transformers.

c) The RRRP received by API is essentially a replacement of distribution revenue that would have otherwise been allocated to the Residential – R1 and Residential – R2 customer classes. In the Rate Design Module, submitted as part of the Application, at Tab [2007 GLP DRO], the RRRP has been apportioned to the applicable customer classes in a reconciliation of total distribution revenue recovery. This is shown below.

**Table C10 - Revenue Recovery Summary**
**EB-2007-0744 Draft Rate Order**

| | 2007 Revenue Requirement | Total Revenue from Rates | RRRP | Approved Deferrals | Total Revenue | Annual Revenue Shortfall |
|---|---|---|---|---|---|---|
| **Residential - R1** | 12,420,000 | 4,821,500 | 7,926,800 | | 12,748,300 | |
| **Residential - R2** | 2,098,200 | 834,900 | 935,000 | | 1,769,900 | |
| **Seasonal** | 2,710,100 | 1,880,500 | | 829,600 | 2,710,100 | |
| **Street Lighting** | 53,800 | 44,200 | | | 44,200 | 9,500 |
| **Totals** | 17,282,100 | 7,581,100 | 8,861,800 | 829,600 | 17,272,500 | 9,500 |

This table is a reproduction of Table C-10 from the Draft Rate Order in the matter of EB-2007-0744. In the table the total RRRP of $8,861,800 is apportioned to the Residential – R1 and Residential – R2 customer classes for purposes of determining the total revenue requirement from rates (net of the $9,500 from Street Lights).

In order to design test year distribution rates that reflect each customer class's contribution to the total revenue requirement from distribution rates, it is necessary to simulate a class distribution rate that recovers the revenue from rates combined with the revenue contribution from the RRRP. The lower table of Tab [2007 GLP DRO], shown below, does this.

**Simulated Distribution Rates to Recover Total Revenue Requirement**
**Data From EB-2007-0744 Draft Rate Order**

| | Metric | Billing Determinant | No. of Customers | Revenue | Monthly Service Charge | Volumetric Distribution Charge | Fixed Revenue Amount | Variable Revenue Amount |
|---|---|---|---|---|---|---|---|---|
| **Residential - R1** | kWh | 101,468,266 | 7,775 | 12,748,300 | 20.41 | 0.1069 | 1,904,253 | 10,844,047 |
| **Residential - R2** | kW | 191,492 | 51 | 1,769,900 | 596.12 | 7.3375 | 364,825 | 1,405,075 |
| **Seasonal** | kWh | 11,657,297 | 3,696 | 2,710,100 | 24.00 | 0.1412 | 1,064,448 | 1,645,652 |
| **Street Lighting** | kWh | 891,877 | 1,052 | 53,700 | - | 0.0602 | - | 53,700 |
| **Totals** | | | 12,574 | 17,282,000 | | | 3,333,526 | 13,948,474 |

Here, using the customer numbers and billing determinants from EB-2007-0744 and the Total Revenue Requirement from Table C-10 shown earlier (including the $9,500 from Street Lights), it is possible to determine base distribution rates for each customer class to recover the full revenue requirement. Essentially these are the Board approved rates of EB-2007-0744 plus the marginal volumetric rate that would have been required to collect the RRRP plus the approved Seasonal Deferral plus the foregone Street Light revenue.

Since this simulation is required only to determine each customer class's contribution to revenue requirement for future rate design and will have to be removed again to establish new rates and RRRP requirement, it is more transparent to apply it only to the volumetric rate.

The adjustment was made only to the Residential – R1 and Residential – R2 customer classes because only the revenue requirement of these customers receives RRRP funding.

d) The derivation of the distribution revenue from rates shown in the Workforms and again in Revenue Deficiency/Sufficiency calculation in Exhibit 6 Tab 1 Schedule 1 was explained in the reply to VECC Interrogatory No. 4. In that explanation it was shown that the revenues are determined on a monthly basis and customers are added monthly and as such the volumetric average use per customer is picked up as the new customers are added to the customer count. The 2010 and 2011 revenues referenced in question (d) above, are calculated on the basis of the average number of customers and volumes for the year. This slight variation combined with the exaggerated volumetric rate (due to the inclusion of the RRRP revenue) results in the minor variations between the two.

## Question #15

**Reference:** Exhibit 3, Tab 2, Schedule 2, Appendix A

a) Please explain why the class shares for 2009 were used to apportion the WSL kWh to customer classes when Table 4 shows a definite trend in the class shares for R-1 (decreasing annually) and R-2 (increasing annually).

b) Does the customer count forecast include any allowance for a continuing migration of Seasonal customers to R1 (as discussed at page 4 of 3/2/1)? If yes, what degree of migration is assumed? If not, why not?

---

**RESPONSE:**

a) Class shares for 2009 were used to apportion the forecast WSL kWh to customer classes as this is the most recent actual year available. API considers that any "forecast" of class shares would likely be viewed as arbitrary. In addition it is API's understanding that the most recent historical year approach for apportioning forecast kWh to classes has been used and approved in the past.

b) No explicit adjustment has been made to account for this migration. However, the customer count forecast for both of these classes is based on the average growth seen over the 2003 – 2009 period, which implicitly takes into account the movement between classes.

## Question #16

**Reference:** Exhibit 3, Tab 3, Schedule 1

a) Why is there no forecast interest income for 2010 and 2011?

b) Why is it appropriate to introduce a specific service charge for pulling post-dated cheques? In the alternative, wouldn't Algoma have to process the receipt of individual payments received by mail or over-the-counter?

---

**RESPONSE:**

a) Please see response to Board staff#24.

b) This charge is to cover the cost of pulling from API files, any post dated cheque that has already been entered, a receipt printed, and given to the customer. The cost covers the administrative costs, and mailing of a post dated cheque(s) back to the customer.

**Question #17**

**Reference:** Exhibit 4, Tab 1, Schedule 1

a) Does the forecast OM&A cost for either 2010 and/or 2011 take into account the impact of the introduction of HST as of July 1, 2010? If yes, where in the Application is this addressed?

b) If no, how does Algoma proposed to address the impact on costs and what was the level of PST included in Algoma's OM&A costs for 2008 and 2009?

---

**RESPONSE:**

a) Please see response to OEB-5.

b) Please see responses to OEB-5 and VECC-11(e).

**Question #18**

**Reference:** Exhibit 4, Tab 1, Schedule 1, Appendix B

a) Please provide the page reference for the Board's EB-2007-0744 Decision where the 6-year cycle was specifically addressed and approved.

b) Is it necessary to continue with the 6-year cycle once the ROW capital program is completed?

c) Page 3 suggests that the current level of spending (e.g. 2010) does not provide for a 6-year cycle. Please explain more fully why this is the case. Please also indicate what level of spending (in 2010 $) would be consistent with a six-year cycle once the ROW expansion program is completed in 2011

---

**RESPONSE:**

a) While there is no direct reference to the 6-year cycle or API's vegetation management program in the decision, there were a number of references made during the EB-2007-0744 preceding. The 6-cycle was presented in prefiled evidence (EB-2007-0744, Exhibit 2, Tab 1, Schedule 1) and explored by Board Staff in their Interrogatory Question 2. In its decision dated October 30, 2008, the board accepted the OM&A expenses submitted in its findings.

*"Based on the evidence provided, the Board considers that the overall level of the proposed increase is reasonable and, accordingly, accepts the Applicant's proposed Controllable OM&A expenses. OEB Decision EB-2007-0744 dated October 30, 2008, page 15"*

b) Yes, this is as detailed in Exhibit 2, Tab 2, Schedule 1.

c) The two main areas for the current level of spending are the maintenance program operating concurrently with expansion program and the brush control retreatment program further explained in Exhibit 4, Tab 1, Schedule 1, Appendix B, pgs 3-4. The brush control program, since 2007 has been retreating areas of our system working to establish a 6 year brush control cycle. As the line clearing portion of our maintenance program returns to previously expanded ROW, the sections will have approximately 9 years of growth, thus having a larger volume of material to be processed. To predict the volume of work and associated spending if we were returning on a 6 year cycle in 2010 is difficult. Each cycle would be assessed prior to budgeting the spending to take into account stem counts of non-compatible species, herbicide application, landowner or municipality concerns. Circumstances will change between different years and cycles which would have an impact on volume of work. However, it is estimated by API that the cost of the 6 year cycle will be in the magnitude forecasted for

2012 and 2013. Please refer to OEB question 27 for projected cost for 2012 and 2013.

**<u>Question #19</u>**

**Reference:** Exhibit 4, Tab 2, Schedule 3

a) Please describe what the increased maintenance activities for 2010 are that contribute to the $174,513 increase in OM&A and why they are considered ongoing activities in subsequent years.

b) What is the basis for the increase in forecasted costs for 2010 and 2011 associated with Outage and System Events (see also Exhibit 4, Tab 3, Schedule 1, page 6)?

---

**RESPONSE:**

a) This cost driver is primarily related to the variance identified in Exhibit 4, Tab 3, Schedule 1, page 6 (lines 1 – 5). The expenditure will remain at that level in subsequent years as API has tried to evenly spread larger maintenance projects. In 2011 API will be conducting arc flash studies throughout its system.

b) The increase in forecasted costs for 2011 in this category is related to wage increase forecast for 2011. A similar level of activity is expected to occur.

## Question #20

**Reference:** Exhibit 4, Tab 3, Schedule 1

a) With respect to page 5, please provide an explanation of the increase in Management Salaries and Expenses from 2009 to 2010.

b) With respect to page 5, please provide an explanation of the increase in General Admin Salaries and Expenses from 2009 to 2010.

c) With respect to page 5, please re-do the table including a separate column for 2011. Please provide an explanation of the 2010 to 2011 changes for any line item where the variance is more than 3%.

---

**RESPONSE:**

a) The exercise of reviewing the individual account activity and isolating the activity in this account is impracticable, as a result of a number of changes in the operations and resulting methodologies during the year 2009. The operations of the distribution business started out the year as a division of a combined entity, and then to a stand-alone entity, and then again changed to an acquired entity with corporate allocations. Based on these changes, a more meaningful review is to examine the aggregate variances, which is approximately $288,000 between 2009 Actual and 2010 Test Year. This aggregate variance analysis is discussed in more detail in Exhibit 4, Tab 3, Schedule 1, page 5 of 7.

b) See answer to part (a) above.

c)

| Expense Description | 2007 Board Approved | 2009 Actual | 2010 Test Year | 2011 Test Year | Variance (2010) from 2007 Board Approved | | Variance (2010) from 2009 Actual | | 2011 Variance from 2010 | |
|---|---|---|---|---|---|---|---|---|---|---|
| Management Salaries and Exp | 218 | 397 | 967 | 980 | | | | | 13 | 1.4% |
| General Adm Salaries and Exp | 749 | 791 | 930 | 955 | | | | | 25 | 2.7% |
| Office Supplies and Exp | 170 | 355 | 256 | 261 | | | | | 5 | 1.9% |
| Outside Services Employed | 856 | 732 | 409 | 539 | | | | | 130 | 31.9% |
| | 1,992 | 2,275 | 2,563 | 2,736 | 571 | 28.6% | 288 | 12.7% | 173 | 6.8% |

The variance in Outside Services Employed between 2010 and 2011 Test Years is primarily the result of an increase of approximately $118,000 for additional IT expenditures related to licensing and maintenance fees for SAP, infrastructure, communications and other software.

**Question #21**

**Reference:** Exhibit 4, Tab 4, Schedule 1

a) With respect to page 3, please explain how cost reductions benefit ratepayers through lower rates when rates are already set based on forecast costs. In reality won't cost reductions lead to higher net income for the year concerned as opposed to lower rates?

---

**RESPONSE:**

Cost reductions benefit ratepayers over time since future operating costs have a direct impact on the revenue requirement being requested in subsequent rate applications of API.

## Question #22

**Reference:** Exhibit 4, Tab 4, Schedule 2

a) Please indicate how much of the Compensation Capitalized for 2010 and 2011 is due to the change in overhead capitalization policy.

b) Please confirm that the FTEs and Salary & Wages reported do not include any of the FTE's or allocated costs associated with services provided by affiliates (of either GLPD or Algoma).

c) Does Algoma forecast that it will be employing any apprentices in 2010 or 2011? If yes, how many and for what positions?

---

**RESPONSE:**

a) There has been no change to the direct overhead capitalization practice that impacted the capitalized compensation that is shown on Exhibit 4, Tab 4, Schedule 2.

b) API confirms that this Schedule does not include any FTEs or allocated costs associated with affiliates of API (formerly GLPD).

c) Yes.

Included in the forecast by department are the following positions:

- Lines – 2 third year apprentices (1 currently on staff and a planned new hire)
- Forestry – 2 third year apprentices (1 currently on staff and a planned new hire)

Also, the Line trades are supplemented by temporary staff from the Line's Trades School at Cambrian College in Sudbury.

**Question #23**

**Reference:** Exhibit 4, Tab 5, Schedule 1

a) Please provide copies of the Service Agreements between Algoma and the various affiliates that provide/purchase services.

b) Please provide a schedule that indicates how, prior to the acquisition by CNPI, GLPD obtained each of the "shared services" set out on page 6 of the BDR Study. In particular, were any of the services provided directly by GLPD staff and, if so, which ones?

c) If any of the services were previously provided internally, please indicate where in the Application the reduction in required internal resources is reflected.

d) Please provide a breakdown of the $373 k in allocated costs from FortisOntario as between the various categories set out in the BDR study – page 6.

e) Please confirm that the $56 k in costs from Fortis Inc. for 2010 relates to the various services discussed on pages 2, lines 22-30. Do any of these services relate to the management of Algoma's debt, either that held by Fortis or that to be issued separately by Algoma?

f) What specific services does CNPI provide for the $134 k charge in 2010? Please also describe how the $134 k charge was established.

g) Is the rental allocation of $19 k for the facilities described in section 6.8 of the BDR report? If not, please describe the facilities involved and why Algoma is responsible for (a portion of) the costs.

---

**RESPONSE:**

a) Please refer to Exhibit 4, Tab 5, Schedule 1 ("Services Agreements") and to response OEB IR 35A.

b) Prior to the acquisition by FortisOntario, GLPD obtained the following services from the entity referred to opposite the service:

| | |
|---|---|
| Executive Services | GLPL Allocation |
| Finance | GLPL Allocation |
| Information Technology | GLPT |
| Health, Safety & Environment | GLPT |
| Regulatory | Contracted services |
| Engineering Design | Contracted services |

c) Not Applicable.

d) Please refer to the response to OEB IR #36b.

e) Yes, the $56 k relates to the various services discussed on page 2, lines 22-30. No, these services do not relate to the management of API's debt.

f) Please refer to the response to OEB IR #36b.

g) Yes, it is described in section 6.8 of the BDR report.

**<u>Question #24</u>**

**Reference:** Exhibit 5, Tab 1, Schedule 1, page 2

a) Please provide an update regarding the status of the planned 2010 debt issue. Please include Algoma's current expectation as to the interest rate that will be associated with the new debt.

---

**RESPONSE:**

API does not expect this private placement to be completed until late 2010 or 2011. API expects an interest rate of 5.5% to 6% which depends on a numbers of factors including Bank of Canada rates, credit spreads, and the term of the facility.

## Question #25

**Reference:** Exhibit 6, Tab 1, Schedule 1

a) Please provide a schedule that sets out (by customer class) the derivation of the Distribution Revenues shown for 2010 and 2011 (e.g., $17,619,307 for 2010).

b) Please reconcile the Distribution Revenues reported here for 2010 and 2011 with those reported in Tables 1 and 2 of Exhibit 3, Tab 2, Schedule 2.

---

**RESPONSE:**

a) This information was provided in the response to VECC Interrogatory No. 4a.

b) This information was provided in the response to VECC Interrogatory No. 14 part (d).

**<u>Question #26</u>**

**Reference:** Exhibit 7, Tab 1, Schedule 1

a) Please explain the basis for the "Percentage of Revenue" values set out in Table 1 (page 1).

b) Please provide details as to how the Distribution Revenues by customer class used in the cost allocation model were determined (Table 4 – page 4). The ERA Report – page 10 suggests they are based on the proposed 2010 rates but the ratios do not match the proposed ratios for 2010. Please also explain how the revenue associate with the RRRP was allocated to customer classes for purposes of the cost allocation.

c) What is the basis for the Service Revenue Requirement of $17,689,706 used in the 2010 Cost Allocation?

d) Please explain why the total costs included in the 2010 Cost Allocation model ($17,689,706) do not equal the proposed 2010 Service Revenue Requirement ($18,928,065). This appears to be inconsistent with the ERA Report which states that the 2010 cost data was used.

e) Please provide a 2010 Cost Allocation based on the proposed 2010 Service Revenue Requirement in accordance with the Board's Filing Guidelines.

f) With respect to the second Table on page 6, please provide schedules setting out how the values in each column were determined.

g) With respect to the proposed revenue to cost ratios (page 6 – first Table), please explain why the ratio for Seasonal is reduced to 100% in 2011 while the ratio for R1 is only reduced to 113.9%. What would be the resulting revenue to cost ratio, if the same ratio was adopted for both classes in 2011 with objective of collecting the equivalent overall revenue from the two classes?

---

**RESPONSE:**

a) The percentage values presented in Exhibit 7, Tab 1, Schedule 1, Table 1 page 1 are the percentages of revenue derived from distribution rates and allocated on the basis of the Board Approved 2007 EDR, EB-2007-0744.

b) The Distribution Revenue by customer class used in the allocation model was determined by applying the customer class revenue allocation approved in EB-2007-0744 (described in part (a)) to the 2010 base revenue requirement.

The RRRP was allocated to the Residential – R1 and Residential – R2 customer classes in the manner described in the Board Approved EB-2007-0744 and discussed in the response to VECC Interrogatory No. 14, part (c).

c) There were inadvertent oversights on the part of the Applicant during the production of the Cost Allocation study. The distribution revenues were not updated to reflect proposed 2010 revenue requirement. As well several of the OM&A accounts were revised based on the final Application filed on June 1, 2010. The distribution revenue in that Model was based on current distribution rates, RRRP funding and normalized forecasted volumes; it did not account for the revenue deficiency.

d) As described in part (c), the Cost Allocation Model filed with the Application was not populated with final revenue requirement information and therefore a new model will be filed concurrently with these interrogatories.

e) An updated 2010 Cost Allocation Model is being filed concurrently with the filing of Algoma's responses to these interrogatories. Output Sheets O1 and O2 are provided here.

2006 Cost Allocation Information Filing
Algoma Power Inc.
EB-2010-0278
Tuesday, June 01, 2010

Ontario

## Sheet O1 Revenue to Cost Summary Worksheet - First Run

**Class Revenue, Cost Analysis, and Return on Rate Base**

| | | | 1 | 2 | 7 | 12 |
|---|---|---|---|---|---|---|
| **Rate Base Assets** | | **Total** | **R1** | **R2** | **Street Light** | **Seasonal** |
| **crev** | Distribution Revenue (sale) | **$18,585,008** | $13,709,481 | $1,903,345 | $57,749 | $2,914,433 |
| **mi** | Miscellaneous Revenue (mi) | **$343,057** | $217,490 | $88,133 | $5,003 | $32,431 |
| | **Total Revenue** | **$18,928,065** | **$13,926,971** | **$1,991,478** | **$62,752** | **$2,946,864** |
| | **Expenses** | | | | | |
| **di** | Distribution Costs (di) | **$4,712,464** | $2,835,059 | $1,290,517 | $87,388 | $499,501 |
| **cu** | Customer Related Costs (cu) | **$1,693,808** | $1,394,715 | $91,659 | $11,235 | $196,199 |
| **ad** | General and Administration (ad) | **$2,632,964** | $1,725,449 | $583,912 | $40,420 | $283,183 |
| **dep** | Depreciation and Amortization (dep) | **$4,056,672** | $2,563,128 | $975,345 | $70,644 | $447,555 |
| **INPUT** | PILs (INPUT) | **$751,038** | $456,888 | $209,628 | $11,219 | $73,304 |
| **INT** | Interest | **$2,342,458** | $1,425,014 | $653,821 | $34,991 | $228,631 |
| | **Total Expenses** | **$16,189,405** | **$10,400,253** | **$3,804,882** | **$255,898** | **$1,728,372** |
| | **Direct Allocation** | **$0** | **$0** | **$0** | **$0** | **$0** |
| **NI** | Allocated Net Income (NI) | **$2,738,660** | $1,666,040 | $764,408 | $40,910 | $267,302 |
| | **Revenue Requirement (includes NI)** | **$18,928,065** | $12,066,293 | $4,569,290 | $296,807 | $1,995,675 |
| | | **Revenue Requirement Input Does Not Equal Output** | | | | |
| | **Rate Base Calculation** | | | | | |
| | **Net Assets** | | | | | |
| **dp** | Distribution Plant - Gross | **$101,557,858** | $61,697,989 | $27,444,170 | $1,706,422 | $10,709,276 |
| **gp** | General Plant - Gross | **$10,530,382** | $6,406,067 | $2,939,214 | $157,302 | $1,027,799 |
| **accum dep** | Accumulated Depreciation | **($46,509,937)** | ($28,210,059) | ($12,079,334) | ($884,122) | ($5,336,422) |
| **co** | Capital Contribution | **$0** | $0 | $0 | $0 | $0 |
| | **Total Net Plant** | **$65,578,302** | **$39,893,997** | **$18,304,050** | **$979,602** | **$6,400,653** |
| | **Directly Allocated Net Fixed Assets** | **$0** | **$0** | **$0** | **$0** | **$0** |
| **COP** | Cost of Power (COP) | **$17,166,389** | $9,553,250 | $6,404,606 | $72,227 | $1,136,306 |
| | OM&A Expenses | **$9,039,237** | $5,955,223 | $1,966,088 | $139,043 | $978,883 |
| | Directly Allocated Expenses | **$0** | $0 | $0 | $0 | $0 |
| | ***Subtotal*** | ***$26,205,626*** | ***$15,508,473*** | ***$8,370,694*** | ***$211,270*** | ***$2,115,188*** |
| | **Working Capital** | **$3,930,844** | **$2,326,271** | **$1,255,604** | **$31,691** | **$317,278** |
| | **Total Rate Base** | **$69,509,146** | **$42,220,268** | **$19,559,654** | **$1,011,293** | **$6,717,932** |
| | | **Rate Base Input equals Output** | | | | |
| | **Equity Component of Rate Base** | **$0** | **$0** | **$0** | **$0** | **$0** |
| | **Net Income on Allocated Assets** | **$2,738,660** | **$3,526,718** | **($1,813,404)** | **($193,145)** | **$1,218,492** |
| | **Net Income on Direct Allocation Assets** | **$0** | **$0** | **$0** | **$0** | **$0** |
| | **Net Income** | **$2,738,660** | **$3,526,718** | **($1,813,404)** | **($193,145)** | **$1,218,492** |
| | **RATIOS ANALYSIS** | | | | | |
| | REVENUE TO EXPENSES % | **100.00%** | 115.42% | 43.58% | 21.14% | 147.66% |
| | EXISTING REVENUE MINUS ALLOCATED COSTS | **$0** | $1,860,678 | ($2,577,812) | ($234,055) | $951,190 |
| | RETURN ON EQUITY COMPONENT OF RATE BASE | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |

2006 Cost Allocation Information Filing
Algoma Power Inc.
EB-2010-0278
Tuesday, June 01, 2010
**Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - First Run**

**Output sheet showing minimum and maximum level for Monthly Fixed Charge**

| | 1 | 2 | 7 | 12 |
|---|---|---|---|---|
| **Summary** | R1 | R2 | Street Light | Seasonal |
| Customer Unit Cost per month - Avoided Cost | $13.09 | $149.43 | $0.96 | $5.09 |
| Customer Unit Cost per month - Directly Related | $18.31 | $210.53 | $1.38 | $6.90 |
| Customer Unit Cost per month - Minimum System with PLCC Adjustment | $39.98 | $248.68 | $28.52 | $22.54 |
| Fixed Charge per approved 2007 EDR | $20.41 | $596.12 | $0.00 | $24.00 |

f) An updated version of second Table on page 6 of Exhibit 7, Tab 1, Schedule 1, produced on the basis of the Cost Allocation Model, API 2010 CA Model_20100816, is provided here together with an explanation of the columns.

## 2010 Test Year Revenue Impacts

| Customer Class | Current Revenue | Test Year Revenue Assuming Current Revenue to Cost Ratios | Test Year Revenue Assuming Proposed Revenue to Cost Ratios |
|---|---|---|---|
| Residential – R1 | 13,375,007 | 13,926,971 | 14,138,880 |
| Residential – R2 | 1,540,475 | 1,991,478 | 2,349,027 |
| Seasonal | 2,842,359 | 2,946,864 | 2,293,032 |
| Street Lights | 52,689 | 62,752 | 147,126 |
| | 17,810,530 | 18,928,065 | 18,928,065 |

The Current Revenue column is the sum of revenue from current distribution rates times the weather normal forecast volumes plus the miscellaneous revenues.

The Test Year Revenue Assuming Current Revenue to Cost Ratios is those revenues determined by the Cost Allocation Model, API 2010 CA Model_20100816.

The Test Year Revenue Assuming Proposed Revenue to Cost Ratios is those revenues determined by the Rate Design Model, API_RateDesignModule_20100607Ad1.

g) In the Board's Decision and Order, EB-2007-0744, related to mitigation for Seasonal Customers, the Board wrote;

> *In its next rate application the Applicant is required to present a planned approach for the management of the mitigation plan so as to ensure that balances are cleared with regularity, at levels and in a manner that does not result in undue hardship for these customers or any other class of customers.*

In this rate design, Algoma is proposing that the revenue to cost ratios for the Seasonal Class customers be allowed to approach 100% over the two years, more rapidly than the Residential – R1 Class. This allows clearance of the deferral account and establishes a distribution rate that does not result in undue hardship for the Seasonal Customers or any other class of customers.

If API were to reduce the revenue to cost ratio for both classes in 2011 with objective of collecting the equivalent overall revenue from the two classes the resulting revenue to cost ratio would be 111.9%. The detail calculation, based on the API's rate design, is shown below. It s a reproduction of Tab [2011 Cost Allocation Design] from the Rate Design Module.

**2011 Cost Allcoaction Results**

| | Cost Allocation Revenue Requirement | Revenue Requirement Allocation Percentage | Cost Allocation Misc. | Cost Allocation Misc. Percentage | 2011 Service Revenue Requirement | 2011 Misc. Revenue | 2011 Base Revenue Requirement | | |
|---|---|---|---|---|---|---|---|---|---|
| Residential - R1 | 11,313,812 | 64.0% | 217,490 | 63.4% | 13,080,580 | 234,623 | 12,845,958 | | |
| Residential - R2 | 4,225,828 | 23.9% | 88,133 | 25.7% | 4,885,734 | 95,075 | 4,790,659 | | |
| Seasonal | 1,872,334 | 10.6% | 32,431 | 9.5% | 2,164,718 | 34,986 | 2,129,732 | | |
| Street Lighting | 277,732 | 1.6% | 5,003 | 1.5% | 321,103 | 5,397 | 315,706 | | |
| | 17,689,706 | 100.0% | 343,057 | 100.0% | 20,452,136 | 370,082 | 20,082,054 | | |

**2011 Base Distribution Rate Cost Allcation Design**

| | 2011 Forecasted Revenue @ 100% R\|C | Revenue Proportions @ 100% R\|C | Proposed Proportion of Revenue | Base Revenue @ Proposed Proportion | Over/(Under) Contributing | Proposed Revenue to Cost Ratio | 2010 Cost Allocation R\|C | Board's Guideline | Two Third Increment |
|---|---|---|---|---|---|---|---|---|---|
| Residential - R1 | 12,845,958 | 64.0% | 71.6% | 14,373,093 | 1,527,136 | 111.9% | 118.22% | 85-115% | Beneficary |
| Residential - R2 | 4,790,659 | 23.9% | 15.6% | 3,137,280 | (1,653,379) | 65.5% | 36.45% | 80-180% | 65.5% |
| Seasonal | 2,129,732 | 10.6% | 11.9% | 2,383,170 | 253,438 | 111.9% | 151.81% | 85-115% | 100.0% |
| Street Lighting | 315,706 | 1.6% | 0.9% | 188,510 | (127,195) | 59.7% | 18.97% | 70-120% | 59.7% |
| | 20,082,054 | 100.0% | 100.0% | 20,082,054 | | | | | |

**<u>Question #27</u>**

**Reference:** Exhibit 8, Tab 1, Schedule 2

a) Please file any working papers/analysis provided by Board Staff to support the 5.5% increase for 2010.

b) With respect to page 3, why is the RRRP assumed to only impact the volumetric rates?

c) With respect to the RateDesignModdule – 2010 Cost Allocation Design Sheet, please confirm that the proposed revenue to cost ratios are calculated using the Base Distribution Revenue Requirement and not the overall Service Revenue Requirement as is done in the OEB's Cost Allocation Model.

d) What are the 2010 revenue to cost ratios for each customer class based on the Total Revenue and Allocated Service Revenue Requirement for each class?

---

**RESPONSE:**

a) Algoma was directed by email from Board Staff to amend its original Application and use an increase of 5.5% in 2010 and 2.0% in 2011. Algoma does not have any supporting documentation or analysis to support these values.

   A copy of the email message follows part (d) of this Interrogatory. Please note that the 5.5% and 2.0% simply serve as placeholders until the averages for the rate adjustments are determined by the Board.

b) There is no assumption that RRRP impacts only the volumetric rates. In the rate design it is necessary to assign the RRRP revenue funding to the specific classes to which it is attributable. As described in API's response to VECC IR 14 c, the assignment of the RRRP is consistent with the Board approved rate design in EB-2007-0744. For simplicity and transparency the entire allocation of RRRP funding was layered onto the volumetric rate. This methodology allowed consistency throughout the rate design and for a transparent removal of the RRRP funding from core rates and application of the base rate increases described in part (a) above.

c) API confirms that the proposed revenue to cost ratios are calculated using the Base Distribution Revenue Requirement and not the overall Service Revenue Requirement. However, the allocation methodology accounts for the cost allocation of the revenue offsets to allow allocation of the distribution revenue from rates.

d) Please refer to the updated Cost Allocation Model, API 2010 CA Model_20100816, discussed in the response to VECC IR 26.

## Bradbury, Doug

**From:** Richard Battista [Richard.Battista@oeb.gov.on.ca]
**Sent:** Thursday, June 03, 2010 3:57 PM
**To:** Bradbury, Doug
**Subject:** EB-2009-0278 Algoma Power Inc.

Hello Doug:

Pursuant to our earlier conversation regarding the Rural Rate Protection calculation factor, the average increase in 2010 for other distributors' delivery rates is now about 5.5%. I believe the filed evidence uses .7% and was based on the data available when the factor was prepared.

With respect to the adjustment for 2011, there haven't been any decisions/rate orders to date for 2011. The filed evidence uses .7%. You might want to consider using something for the time being in the 2% range. Of course this is only a suggestion since as of yet there is nothing factual to reference.

And finally, I believe that you are ok with updating the bill impact calculations also using 800 kWhs.

If you have any questions please let me know.

PS: In due course, I'd appreciate it if you could let me know by approximately when the updates would be filed.

Thanks,
Richard Battista
Project Advisor
Ontario Energy Board

Tel:416.544.5174
E-mail: richard.battista@oeb.gov.on.ca

## Question #28

**Reference:** Exhibit 8, Tab 2, Schedule 1
OEB #48

a) Do the proposed monthly service charges for any of the four customer classes exceed the upper bound identified in response to part (a)? Apart from the Seasonal class, if the response is yes please explain why Algoma is proposing to increase the value of the monthly service charge in 2010.

b) In Algoma's view does the Regulation require <u>each</u> "Residential" customer's bill to increase by the "average" or is it sufficient that the total bills for all customers in the class increase by the average?

---

**RESPONSE:**

a) As discussed in the response to SEC IR 29, the 2010 proposed fixed monthly charge for the Residential – R2 class is $628.91 and it exceeds the Cost Allocation customer unit cost per month for Minimum System with PLCC of $303.50.

The proposed fixed monthly charge of $628.91 equates to a 5.5% increase to the EB-2007-0744 approved rate of $596.12 in accordance with the methodology prescribed in the Board's Decision and Order, EB-2007-0744, dated October 30, 2008.

In addition and as described in SEC IR 29, API is cognizant of the pressures facing industry in Northern Ontario. As with any change in the fixed monthly charge for a customer class there will be certain customers that are impacted more than others within the class. Reducing the fixed monthly charge to $303.50 will benefit the small volume users and the corresponding increase in the volumetric rate will impact the larger volume users within the class. Given the stresses already facing industry in Northern Ontario, an increase in volumetric rate may not be advantageous.

In this Application, API has elected to maintain the current rate structure and limit the change in the fixed monthly charge to the simple average increase in Delivery Charge per Ontario Regulation 442/01. This strategy is to maintain rate stability within the Residential R2 Class.

b) There is a discussion of the calculation of *RRRP – Average Rate Adjustments for Other Distributors* on pages 29 and 30 of the Board's Decision and Order, EB-2007-0744, dated October 30, 2008. Beginning on page 29, it states;

> *Section 4 (3.2) of that regulation requires forecasted customer revenues to be based on currently approved rates "adjusted in line with the average, as calculated by the Board, of any adjustment to rates approved by the Board for other distributors for the same year."*

API's position is consistent with the rate design approved in EB-2007-0744 in which the fixed and volumetric distribution rates required to recover the revenue requirement from distribution rates are adjusted by the average of rates approved for other distributors. In fairness to all customers within that customer class, each customer's rate should reflect the same increase.

## Question #29

**Reference:** Exhibit 9, Exhibit 1, Schedule 1

a) What is the basis for the 2009 additions to Account #1508?

---

**RESPONSE:**

The additions in account 1508 represent one-time administrative incremental IFRS transition costs.

**<u>Question #30</u>**

**Reference:** Exhibit 9, Tab 2, Schedule 2

a) Please provide greater details on exactly what the $410,695 was incurred for (e.g. external services purchased and why they were required) and the time period over which they were incurred.

b) For how long has GLPL (GLPD) been aware that it would need to comply with Section 71?

c) Please provide a timeline showing the activities undertaken by GLPL (GLPD) in order to comply with Section 71.

---

**RESPONSE:**

a) Costs for this claim were incurred between November 2008 and December 2009, and breakdown as follows:

Legal ($284,200)
- Representation in connection with discussions/applications made with the Ministry of Energy, Ontario Energy Board, IESO

Consultants ($66,390)
- Outside consultants used primarily in the separation of engineering records

Internal Costs ($56,440)
- Internal staff used primarily to assist in the separation of engineering records

Administrative ($3,665)
- Registration fees with Ministry of Finance, IESO

b) GLPL began operating with 3 distinct licenses as of May 1, 2002, which was possible only through the Section 71 exemption. API does not know when GLPL became aware of the expiration of its Section 71 exemption.

c) Timelines for compliance.

**<u>Background</u>**

Section 71(1) of the OEB Act states that:

> "Subject to subsection 70(9) and subsection (2) of this section, a transmitter or distributor shall not, except through one or more affiliates, carry on any business activity other than transmitting or distributing electricity."

Subsections 5(4) and 5(5) of the Regulation provides as follows:

> "(4) Section 71 of the OEB Act does not apply to Cornwall Street Railway Light and Power Company Limited or to Great Lakes Power Limited.
>
> (5) Subsection (4) does not apply after December 31, 2008."

At the time Subsections 5(4) and 5(5) of the Regulation were made, GLPL, as a single corporation, carried on the businesses of generation, transmission and distribution. As such, an exemption to Section 71 was required.

In anticipation of the expiry of the exemption and subsequent to market opening in May 2002, the company began taking steps to separate these businesses. Between 2002 and 2007, GLPL financially and operationally separated its generation, transmission and distribution businesses within the same legal entity. A corporate financing established in 2003 excluded the distribution assets and provided supportive covenants to allow transmission assets to be transferred out of the company.

From 2003 to 2007, GLPL worked with the Ministry of Energy and the Ontario Energy Board to implement solutions to significant rate impacts associated with its exclusively rural distribution business. Recognizing this issue, regulations were passed by the government during the summer of 2007. Immediately following the making of these regulations, GLPL filed with the Ontario Energy Board on August 31, 2007 its distribution rate case incorporating the new regulations. The Board rendered its decision in that matter on October 30, 2008. In order to fully comprehend the financial circumstances of GLPL's distribution business and the resulting rate structure, the reorganization of GLPL's distribution business had been delayed until the outcome of that rate proceeding.

In November 2008, GLPL determined it would pursue separating its distribution business into a separate legal entity. To accomplish this end together with regulatory approvals needed to permit those transactions, the following steps were completed in 2009.

(a) GLPL filed applications on March 9, 2009 seeking the following relief:

   (1) Pursuant to Section 86(1) of the OEB Act, leave to transfer all of its distribution assets (the "Distribution System") to a new legal entity ("NewCo");

   (2) Pursuant to Section 81, a Notice of Proposal;

   (3) Pursuant to Section 60 of the OEB Act, a distribution license for NewCo to own and operate the Distribution System;

(4) Pursuant to Section 18 of the OEB Act, the transfer of GLPL's distribution rate order arising from the Board's Decision and Order in EB-2007-0744, dated October 30, 2007; and

(5) Pursuant to Section 77(5) of the OEB Act, the cancellation of GLPL's distribution and transmission licenses upon the completion of the applicable transaction.

(b) GLPL received the above approvals on May 5, 2009

(c) GLPL completed a series of corporate, financial and real property transactions to enable the sale of its distribution assets to Great Lakes Power Distribution Inc. effective on July 1, 2009.