DECISION

IN THE MATTER OF an application dated May 1, 2008 by the New Brunswick System Operator ("NBSO") for approval of changes to the Open Access Transmission Tariff.

November 26, 2008

NEW BRUNSWICK ENERGY AND UTILITIES BOARD

New Brunswick Energy and Utilities Board

IN THE MATTER OF an Application dated May 1, 2008 by the New Brunswick System Operator for the approval of changes to the Open Access Transmission Tariff.

PARTICIPANTS:

BOARD

Chairman	Raymond Gorman, Q.C.
Vice-Chairman	Cyril Johnston
Member	Donald Barnett
Member	Roger McKenzie
Member	Yvon Normandeau
BOARD STAFF	Ellen Desmond Douglas Goss John Lawton Lorraine Légère

APPLICANT

New Brunswick System Operator	Robert L. Kenny, Q.C. Kevin Roherty George Porter Lynn West Margaret Tracy

FORMAL INTERVENORS

Bayside Power LP	Len Hoyt, Q.C.
Integrys Energy Services, Inc. (“Integrys”)	David MacDougall Edward Howard
New Brunswick Power Distribution And Customer Service Corporation (“Disco”)	Terrence Morrison, Q.C. Blair Kennedy

New Brunswick Power Generation Corporation (“Genco”)	Arden Trenholm Nicole Poirier
Northern Maine Independent System Operator	Kenneth Belcher
Nova Scotia Power System Operator	Eric Ferguson
Oxbow-Sherman	Stacy Dimou
PUBLIC INTERVENOR	Daniel Theriault, Q.C. Robert O’Rourke

The New Brunswick System Operator ("SO") applied to the New Brunswick Energy and Utilities Board ("Board") on May 1, 2008 for approval of changes to the Open Access Transmission Tariff ("OATT"). The application was made pursuant to Section 111 of the *Electricity Act*, as amended ("Act").

The SO also filed a Notice of Motion and an affidavit in support thereof requesting that the Board make an interim order pursuant to Section 40 of the *Energy and Utilities Board Act*, as amended ("EUB ACT") approving changes to the OATT Schedule 1 rates, to be effective from the date of such interim order until further order of the Board.

A pre-hearing conference was held on June 4 at which time a number of preliminary matters were discussed. A public hearing on the Motion for the Interim Order was held on June 11, 2008. The Board granted the Motion and ordered that the Schedule 1 rate changes would take effect, on an interim basis, on July 1, 2008.

The Board's Authority:

Section 111 provides the Board with the authority to approve a tariff application by the SO. The Board will approve the application as applied for if it is determined to be just and reasonable. However, it also has the authority to set a tariff for whatever rates that it finds to be just and reasonable, if it is not satisfied that the applied for rate meets that criteria.

Section 111 of the Act states:

"Application for approval of tariff

111(1) The SO may make application to the Board for approval of a tariff pertaining to the provision of transmission services or ancillary services, or both.

111(2) The Board shall, on receipt of an application from the SO for approval of a tariff pertaining to transmission services or ancillary services, or both, proceed under section 123.

111(3) When an application is made under this section for approval of a tariff pertaining to transmission services, a transmitter shall attend the hearing under section 123 for the purposes of defending its revenue requirements, and is deemed to be a party in the proceedings before the Board.

111(4) The Board shall, when considering an application by the SO in respect of an approval of a tariff pertaining to transmission services, base its order or decision respecting the tariff on all of the projected revenue requirements of the SO and the transmitters for transmission services and the allocation of such revenue requirements between the SO and the transmitters.

111(5) The Board shall, when considering an application by the SO in respect of an approval of a tariff pertaining to ancillary services, allow in its order or decision for mechanisms to recover the reasonable costs incurred by the SO in the acquisition and provision of ancillary services, or base its order or decision respecting the tariff on all of the projected revenues from the sale of ancillary services and all of the projected costs to be incurred by the SO in the acquisition or provision of ancillary services.

111(6) The Board at the conclusion of the hearing shall
(a) approve the tariff, if it is satisfied that the tariff applied for is just and reasonable or, if not so satisfied, fix such other tariff as it finds to be just and reasonable, and
(b) set the time at which any change in the tariff is to take effect.

<u>Proposed Changes to the OATT:</u>

The OATT as first approved by the Board took effect on September 30, 2003 and was later revised on June 15, 2004. The New Brunswick Power Corporation had applied for approval of the original OATT which it administered. Upon proclamation of the Act on October 1, 2004, the SO was given the responsibility for administration of the OATT.

Subsequent changes to the OATT were approved effective on May 1, 2005 and March 1, 2006.

In the current application the SO applied for approval of changes to the rates for the following services:

- Revised rates for mandatory Ancillary Service Schedule 1;
- Revised rates for mandatory Ancillary Service Schedule 2;
- Revised rates for Capacity-Based Ancillary Services ("CBAS") in Schedules 3, 5 and 6
- Rates for a New Regulation and Frequency Response Service to be charged to Wind Generators in Schedule 3(c).

The SO also requested approval of a number of risk mitigation factors that included an automatic escalation for Schedule 1 and 2 rates, an increase in the amount of its retained surplus and a cost of service contingency.

Two sets of interrogatories and responses were exchanged on the evidence filed in support of the proposed OATT changes.

Filing of a Settlement Agreement:

The SO realized large surpluses from the sale of CBAS services for the 2006/2007 and 2007/2008 fiscal years. Parties that contributed to the surpluses contested the SO's proposed distribution of the surpluses. Technical conferences were held at which the parties discussed the contributing factors and the proposed distribution methodologies for the surpluses.

A settlement agreement to distribute the 2006/2007 surplus, which had been negotiated by the parties, was approved by the Board in a decision dated January 29, 2008. That settlement did not provide a methodology to be used in distributing future surpluses.

When the OATT application was filed on May 1, 2008, no agreement for the distribution of the 2007/08 surplus had been achieved. Integrys filed a proposed settlement agreement with the Board on June 19, 2008. The settlement proposed an allocation of the 2007/2008 surplus and a methodology to distribute any surplus for 2008/2009. The agreement also proposed changes to rates for the OATT Schedules 1, 2, 3, 5 and 6. The SO and the NB Power Group of Companies filed letters in support of the proposed settlement agreement.

The agreement included three components, as follows:

1. Allocation of the 2007/2008 Surplus;
2. Allocation of the 2008/2009 Surplus or Deficit; and
3. A commitment to support through the OATT revision process and market rule changes, etc., a “Go Forward” Solution that included:
    - Acceptance of the “Straw Man Proposal”(Exhibit A-1, Tab 5-c);
    - A Monthly Settlement of CBAS Methodology; and
    - A Monthly Settlement of Schedules 1 and 2 Methodology

The agreement proposed a distribution of $2,819,362.12 for 2007/2008 that included $100,000.00 of the Board approved retained surplus. The remaining $200,000.00 of the retained surplus was proposed to be distributed with the 2008/2009 surplus or deficit. Not all parties named in the proposed settlement agreement submitted written comments in support of or against the agreement.

The Board wrote the SO on July 18, 2008 stating that it was unclear what OATT changes were contemplated in the agreement and what the relationship was between those changes and the May 1, 2008 application. The Board ordered the SO to file a document that:

- Clearly identified all of the changes to the OATT for which approval was requested; and
- Provided supporting evidence for each specific change.

<u>Clarification of Tariff Changes:</u>

On July 29, 2008 the SO filed a document titled *"Clarification of Tariff Changes"* ("Filing") in response to the Board's order. The Filing proposed a change from fixed rates to a methodology using monthly formulas to recover the SO's costs.

The Filing proposed that the Board would annually approve the SO's revenue requirement for Schedule 1 and 2 services. A formulaic approach that charged, on a monthly basis, one-twelfth of the requirement on a pro rata basis to customers was proposed beginning on April 1, 2009. A surplus that accrued throughout the year would be distributed to the consumers on a pro rata basis at year end but a deficit would be carried forward and included in a subsequent year's revenue requirement. It was stated that the proposal would provide certainty to the SO for the recovery of its budgeted revenue requirement during the year. It was proposed that the existing rates would remain in effect until April 1, 2009.

The proposal for monthly charges for CBAS Schedules 3, 5 and 6 would be based on the actual monthly expenditures for those services and allocated on a pro rata basis. The proposal was expected to recover the SO's actual costs and to eliminate future surpluses or deficits for those services and would begin on December 1, 2008. The proposed rates for the new Regulation and Frequency Response Service for Wind Generators charged under Schedule 3(c) was unchanged in the settlement agreement.

The Filing proposed the elimination of the $300,000 retained surplus. The settlement agreement proposed that the retained surplus should be distributed with the CBAS surplus for 2007/2008 and 2008/2009. The SO requested the Board to approve a change to the fixed cap on CBAS self-supply. Currently, the self-supply limit for all CBAS is 90 percent and it was proposed to change to an allowable range from 85 to 100 percent.

It was also proposed that future revenue requirements include a $300,000 contingency amount to be used for unexpected or unplanned costs. If, at the end of the SO's fiscal year, expenditures were less than the budget amount then the surplus would be rebated to transmission customers based on their pro rata share of transmission usage in that year. If expenditures were greater than budget then the deficit would be included in the revenue requirement for the following year. No explanation of unexpected or unplanned costs was provided nor was a process to review and approve such expenditures suggested.

A Motions Day was held on August 18, 2008. The Public Intervenor requested the Board to allow an additional set of interrogatories on the Filing information. The Board approved the request for an additional set of interrogatories.

The hearing was held on October 27 – 29, 2008.

<u>Issues and Analysis:</u>

<u>Board Authority With Respect to Charges, Rates and Tolls</u>

During final argument, the Public Intervenor submitted that the Act neither contemplates nor permits variable rate tariffs and as such, the new methodology proposed by the SO is illegal. Reference was made to the definition section of the Act and in particular the definition of "*tariff*" which states as follows:

> “tariff” means a schedule of all charges, rates and tolls, terms and conditions, and classifications, including rules for calculation of tolls, established for the provision of either or both of the following:
>
> *(a)* a transmission service;
>
> *(b)* an ancillary service;(*tariff*)

The Public Intervenor stated that while tariff *includes* the rules for calculating tolls, it cannot replace the inclusion of specific charges, rates and tolls. He argued that the *Electricity Act* was drafted with the intent that only the “traditional regulatory model” of setting rates would be followed.

The Board has carefully considered this issue and after the conclusion of the hearing, invited legal briefs on this particular concern. The Board has received and reviewed briefs that were submitted by the Public Intervenor, Genco & Disco, Integrys and the SO.

At the outset, the Board notes that “formula rates” are not uncommon and have been used in the past, both in New Brunswick and in other jurisdictions. In fact, in any utility ratemaking function, flexibility exists in how rates are designed. Clearly, the Board must determine if the rates which are ultimately charged to customers are “just and reasonable”. When a formulaic approach is adopted, the principle of fairness continues to apply, but from a broader perspective.

In this case, the definition of *tariff* does not preclude the use of a variable rate and there is no requirement that the rate be “fixed” in any fashion. Moreover, the definition of *tariff* must be read in conjunction with other sections of the *Act.* For example, section 111(5) of the *Act* permits the Board to use *mechanisms* to recover the reasonable costs incurred by the SO in the acquisition and provision of ancillary services. Similarly, section 108 states that tariffs which are just and reasonable must be charged *on the same basis or at the same rate*, thereby providing the Board with the opportunity to order something other than a fixed rate. Finally, Section 125 of the *Act* provides that the Board may adopt any method it considers appropriate, in approving or fixing just and reasonable rates.

These provisions, read together, clearly demonstrate that the Board has the authority to approve a range of methods or techniques when setting rates and tariffs. The Board does not believe that the new methodology, proposed by the SO, simply allows for a "pass through of costs" in an informal fashion. The SO will ultimately be required to determine its revenue requirement each year and the discretion of future Board panels to either accept or modify this revenue requirement will not be fettered. The ultimate test both now, and in future reviews, is whether the rates which are set are "just and reasonable" to both the consumer and the SO. The Board finds therefore that it has the authority to approve the use of a mechanism for setting rates as proposed by the SO.

Schedule 1 Services

The 2008/2009 Year

The Board approved an increase in the rates for Schedule 1, on an interim basis, effective July 1, 2008. The SO requested that the interim rates be confirmed for 2008/2009. In support of this request, the SO provided details on its revenue requirement.

In addition to the normal items of expense, the SO included an amount of $300,000 as a contingency intended to deal with unforeseen circumstances. **The Board has reviewed the revenue requirement for 2008/2009 and approves the amount as proposed by the SO.**

No party objected to the interim rates being confirmed. **The Board approves the rates for Schedule 1 that became effective on July 1, 2008, on a final basis. The OATT wording for Schedule 1 services, as found in Attachment "A", is approved.**

Future Years

The SO proposed that, beginning on April 1, 2009, the way in which the revenue requirement would be recovered from Transmission Customers should be changed. The change would be to eliminate the use of fixed rates and instead to recover one-twelfth of the approved annual revenue requirement each month. The actual annual revenue requirement would be approved by the Board, each year, after a public review process.

The monthly amount would be recovered by charges to Transmission Customers based on their pro-rata share of the usage of Schedule 1 services. The actual amount of the monthly charge would not be known in advance and could vary from month to month.

The change would minimize the possibility of a surplus or deficit for Schedule 1 due to changes in actual usage. It would also provide a revenue flow that more closely matches the actual monthly expenses for Schedule 1.

All parties, except the Public Intervenor, supported the change. The Public Intervenor took the position that variable rates are not legal under the Act and therefore could not be approved by the Board.

The Board, as discussed above, finds that it has the authority to approve the recovery of the revenue requirement for Schedule 1 as proposed by the SO. The Board also believes that the proposed change is appropriate in principle. The implementation of such a method does however raise certain issues that are discussed below.

The revenue requirement must be approved by the Board on an annual basis. The Board will do so by way of a full hearing process that is open and transparent. **The SO is**

ordered to file with the Board, as a minimum, in January of each year, the following information:

> **The audited financial results for the last full fiscal year;**
> **The budget for the last full fiscal year;**
> **An explanation of all variances between the budget and the audited results for the last full fiscal year;**
> **The projected results for the current fiscal year;**
> **The budget for the current fiscal year;**
> **An explanation of all variances between the budget and the projected results for the current fiscal year;**
> **The budget for the upcoming fiscal year;**
> **An explanation of all variances between the current year projected results and the audited results for the previous year; and**
> **An explanation of all variances between the current year projected results and the budget for the upcoming year.**

The above information is to be provided in a format similar to that used in Exhibit A-5, Revised Rates and Charges Section, page 8, Table 1 Financial Schedule – Revenue and Expenses. In addition, the SO is to provide separate reports for each of Schedules 3(a), 3(b), 3(c), 5 and 6 that provide a breakdown of the revenue and expense for each of the Capacity Based Ancillary Services.

The Board will establish the actual process that will be used to review this information and that will determine any additional information that the SO will be required to provide. The Board will, as a result of such a review, approve the amount of the revenue requirement for Schedule 1 services for the upcoming year, on an annual basis.

The SO proposed that the OATT contain the following words with respect to any surplus or deficit that might occur for Schedule 1:

> "In the event that in any given fiscal year the actual revenues are anticipated to be less than the actual NBSO operating expenses, net of miscellaneous revenue, such deficit shall be included in the annual revenue requirement submitted to the Board for review with respect to the following fiscal year.
>
> In the event that in any given fiscal year the actual revenues are anticipated to be more than the actual NBSO operating expenses, net of miscellaneous revenue, such surplus shall be rebated to Transmission Customers in proportion to their respective Schedule 1 charges in that fiscal year."

This proposal treats surpluses differently than deficits with respect to the timing of how they would be handled. Further, the above wording does not provide the specific timing nor does it appear to require a determination of the actual amount of surplus or deficit.

The SO, at the hearing, stated that the amount of surplus or deficit would be based on the final audited statements. The SO would rebate any surplus to those Transmission Customers who took service in the previous year but would include any deficit as part of the revenue requirement for the upcoming year.

The Board believes that surpluses and deficits should be treated in a consistent manner. One option would be to include any surplus in the calculation of the revenue requirement for the upcoming year in the same manner as proposed for deficits. The SO and other parties objected to such an approach.

The Board is prepared to allow surpluses to be rebated as proposed so long as deficits are to be billed to the Transmission Customers in a similar manner. **To accomplish this, the**

Board orders the SO to have any audited surplus or deficit reviewed by the Board prior to any action being taken with respect to such surplus or deficit. The SO is ordered to file annually with the Board its audited statements, as soon as they are available, together with an explanation of any surplus or deficit for Schedule 1 services. Once the amount has been reviewed and approved by the Board, it will be rebated or billed to the Transmission Customers from the previous year based on their use of the Schedule 1 services.

The Board therefore orders that the above wording that was proposed by the SO be replaced with the following:

> **"The actual amount of a surplus or deficit for any given fiscal year, as approved by the Board, is to be rebated or billed to Transmission Customers in proportion to their respective Schedule 1 charges for that fiscal year."**

The purpose of the $300,000 contingency and the review of any use of the contingency were the subject of considerable discussion. The position of the SO was that the contingency would be a buffer built into the revenue requirement for Schedule 1 for things that had not been anticipated. The SO stated that it was not intended that use of the contingency would be reviewed except as part of the annual review of the SO's operations. At that time, the Board could decide what adjustments, if any, would be appropriate.

The SO is a not for profit organization and it is appropriate for the SO to have the ability to deal with any significant unanticipated legitimate expenses. The Board will therefore allow a contingency amount to be included as part of the proposed annual revenue requirement for Schedule 1. The contingency amount is only to be used for expenses related to Schedule 1. **The SO is ordered to report each year in January, as part of the annual revenue requirement review process, on any use of the contingency**

amount during the previous year and to justify the amount of the contingency that is being proposed for the upcoming year. The Board may, as a result of the annual review, approve an amount for contingency for the upcoming year.

The Board, subject to the above conditions, approves a change to the method for recovering the costs associated with the provision of Schedule 1 services commencing with the 2009/2010 fiscal year (April 1, 2009). The OATT wording for Schedule 1 services, as found in Attachment "A", is approved.

<u>Schedule 2</u>

The SO proposed that, effective April 1, 2009, the currently approved rates for Schedule 2 services be eliminated and the costs associated with Schedule 2 services be recovered by way of monthly charges to the Transmission Customers that would be based on one-twelfth of the annual revenue requirement as approved by the Board.

The SO stated that the change would match revenues with expenses and that they would know, with certainty, what the annual expenses would be prior to the start of the fiscal year.

The Board agrees with the principle of matching expenses and revenues for Schedule 2 services. The revenue requirement for Schedule 2 services must be approved by the Board. The Board will do so by way of a full hearing process that is open and transparent. The Board believes that both the proposed expenses and the actual charges to the Transmission Customers should be reviewed. **The SO is ordered to file with the Board, in January of each year, information that supports the proposed annual revenue requirement for Schedule 2 and that provides verification that the actual charges to the Transmission Customers, for Schedule 2 services in the previous year, were calculated appropriately.**

The Board will establish the actual process that will be used to review this information and that will determine any additional information that the SO will be required to provide. The Board will, as a result of this review, approve the amount of the revenue requirement for Schedule 2 services for the upcoming year, on an annual basis.

Despite the SO's statement that the actual revenue requirement would be known with certainty prior to the start of the fiscal year the proposed wording for the OATT for Schedule 2 contains a reference to a possible surplus or deficit. The Board has modified this wording to be consistent with the approved wording for Schedule 1. **The OATT wording with respect to possible surpluses/deficits for Schedule 2 services, as found in Attachment "A", is approved.** The wording is shown below:

> "The actual amount of a surplus or deficit for any given fiscal year, as approved by the Board, is to be rebated or billed to Transmission Customers in proportion to their respective Schedule 2 charges for that fiscal year."

The SO is ordered to file annually with the Board its audited statements together with an explanation of any surplus or deficit for Schedule 2 services. Once the amount has been reviewed and approved by the Board, it will be rebated or billed to the Transmission Customers from the previous year based on their use of the Schedule 2 services.

The Board, subject to the above conditions, approves a change to the method for recovering the costs associated with the provision of Schedule 2 services commencing with the 2009/2010 fiscal year. With respect to 2008/2009, the SO in its May 1, 2008 application requested changes to the Schedule 2 rates. The SO stated that the changes would allow the rates to match current conditions. The Public Intervenor recommended approval of the changes proposed by the SO and no party objected to the proposed rates.

The Board therefore approves the rates for Schedule 2, as filed on May 1, 2008, effective December 1, 2008. The OATT wording for Schedule 2 services, as found in Attachment "A", is approved.

Schedules 3(a), 3(b), 5 and 6

The SO proposed that, effective December 1, 2008, the currently approved rates for the existing Schedule 3 services, the Schedule 5 services and the Schedule 6 services be eliminated and that the charges to Transmission Customers would be a pass-through of the actual expenses incurred by the SO each month.

This change, together with certain non-OATT changes, is intended to better align the revenues with expenses and to eliminate cross-subsidization between ancillary service rate classes. The Board believes that such objectives should be pursued and, in principle, agrees with the proposed changes.

The Board notes, however, that the current OATT wording for Schedules 3, 5 and 6 references a number of individual services under each schedule but that the proposed wording does not. The proposed wording refers to "obligations" but does not define how the obligation for each customer is to be determined.

The Board finds that a change to the OATT that does not clearly specify how the actual charge for each Transmission Customer would be calculated is not just and reasonable. **The Board therefore denies the change in methodology as requested by the SO.** The SO in its May 1, 2008 application requested changes to the existing Schedule 3(a), 3(b), 5 and 6 rates. The SO stated that the changes would more properly align the rates with costs and also eliminate cross-subsidization between ancillary service rate classes. The Public Intervenor recommended approval of the changes proposed by the SO and no party objected to the proposed rates.

It is possible that the use of specific fixed rates will result in either a surplus or a deficit for one or more of these services. There has been a surplus for the 2007/2008 year and a surplus is anticipated for the 2008/2009 year. The treatment of these surpluses is discussed below in the section on “The Settlement Agreement”. **Beginning with the 2009/2010 year, the SO is ordered to file annually with the Board its audited statements together with an explanation of any surplus or deficit for each of the Schedule 3(a), 3(b), 5 or 6 services.** Once the amounts have been reviewed and approved by the Board, they will be rebated or billed to the Transmission Customers from the previous year based on their respective use of each of the Schedule 3(a), 3(b), 5 or 6 services.

The Board therefore approves the rates for Schedule 3(a), 3(b), 5 and 6, as filed on May 1, 2008, effective December 1, 2008. The OATT wording for Schedules 3(a), 3(b), 5 and 6 services, as found in Attachment “A”, is approved.

Schedule 3(c)

The SO proposed an addition to Schedule 3 referred to as 3(c) that would establish specific rates to be charged to Non-Dispatchable Wind Power Generators for Automatic Generation Control and Load Following services, for each of the fiscal years 2009/2010 to 2012/2013. The rate is proposed to start on April 1, 2009 at $0.25 per MWh of Wind Energy and escalate by $0.25 each year until it reaches $1.00 per MWh on April 1, 2012. The SO stated that the reason for requesting specific rates was to provide greater certainty to wind power project proponents.

The SO stated that it has not produced estimates for either the expenses or revenues that would be associated with this service. The SO agreed that the revenues may not equal the costs for 3(c) and stated that, if a deficit was expected to continue to exist, it would bring the matter before the Board for resolution.

It is the position of the SO that the Transmission Customers of each ancillary service rate class should pay the expenses of providing that service. The SO also stated that all of the expenses for each of the proposed 3(a) and 3(b) services are to be recovered each month by charges to the Transmission Customers using each of the 3(a) and 3(b) services.

The logical conclusion is that the Transmission Customers of 3(c) must pay the actual expenses incurred to provide this service. The Board can appreciate the value of providing greater certainty but is not prepared to establish a rate structure that could require cross-subsidization to 3(c) from other ancillary services.

The Board approves the initial rate of $0.25 per MWh of Wind Energy, effective April 1, 2009. The Board approves, in principle, the escalation of the rate as proposed by the SO. **The SO is ordered to file with the Board, beginning in 2010, as part of the review of the annual revenue requirement, information on the actual revenues, the actual expenses and the expected expenses for the 3(c) service.** The Board will review that information and make any necessary changes to the 3(c) rate. The intent of any such changes would be to ensure that the 3(c) Transmission Customers are paying the costs of that service.

The SO proposed that the following wording be included in the OATT with respect to 3(c):

> "To the extent that expenses are expected to exceed the revenues for these services, new non-dispatchable wind generation in the balancing area shall self-supply this service in accordance with the Transmission Provider's Market Rules."

There was discussion on the impact that such a requirement could have on potential new wind power projects. The phrase “expenses are expected to exceed the revenues” does not provide clarity with respect to how this requirement would be applied. Further, the record is not clear as to how current wind power generation, in the balancing area, is being treated nor as to why potential new projects should be treated differently. For these reasons, the Board will not approve this wording. **The OATT wording for Schedule 3(c) services, as found in Attachment “A”, is approved.**

The SO is ordered to provide information, as part of the review for the 2010/2011 fiscal year, on whether or not there should be a limit on the amount of wind power energy that will be eligible to receive 3(c) service.

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Cap on Self-Supply of Capacity-Based Ancillary Services (“CBAS”)

The SO proposed that the current requirement whereby Transmission Customers are only permitted to self-supply up to 90% of their CBAS be eliminated. The current cap was approved by the Board in a decision dated August 2, 2006. The SO requested that it be granted the authority to set the limit for self-supply of CBAS within a range of 85-100%.

The SO stated that such an approach would provide greater flexibility for adapting to changing market conditions while providing a degree of certainty to those that would prefer to self-supply. The Board is not convinced that allowing the SO the flexibility to raise or lower the cap on self-supply is consistent with providing protection to Transmission Customers who may wish to self-supply. The Board further notes that the following statement concerning the Cap on Self-Supply was made on page 8, of the “Straw Man Model on CBAS” that was filed as part of the SO evidence:

> “Given that other components within this straw man model are intended to reduce the margin on the services, it may not be necessary to revise the cap.”

All parties, except the Public Intervenor, supported the proposed change to the cap on self-supply. The Public Intervenor recommended that the cap remain as is. The Board believes that when a change to the OATT is proposed the onus is on the SO to demonstrate that such a change is appropriate. The Board does not believe that the SO has provided any compelling evidence that supports the requested change to the currently approved cap on self-supply of CBAS. **The Board therefore denies the requested change and orders that the currently approved cap of 90% remain in effect.**

The Settlement Agreement

The SO included, as part of its evidence, a document referred to as the Settlement Agreement. That document describes an agreement that was reached by the SO, Integrys and the NB Power group of companies on the allocation of the surplus for 2007/2008, the allocation of any surplus/deficit for 2008/2009 and a commitment to support a "Go-Forward" Solution.

All parties, except the Public Intervenor, requested the Board to approve the Settlement Agreement, in its entirety. The Public Intervenor recommended that the Straw Man Model proposal be accepted instead as it was his opinion that the Board cannot approve the changes as proposed by the SO.

The Board has ruled on the various proposed changes to the OATT in the above sections of this decision. With respect to the disbursement of the surplus for 2007/2008 and the treatment of any surplus or deficit for 2008/2009 the Board approves the method proposed in the Settlement Agreement. The Board also approves the elimination of the retained surplus account as the money currently in that account will be disbursed as part of the Settlement Agreement.

The SO is ordered to disburse the surplus for 2007/2008 and to treat any surplus or deficit for 2008/2009 in accordance with the Settlement Agreement.

Other Matters

The Board appreciates the work that the parties have done in discussing the operational surpluses of the SO and in developing proposals that deal with the actual surpluses and with ways that future surpluses or deficits can be minimized or eliminated. The Board, however, must examine such proposals to ensure that they are appropriate and in the best interests of the electricity customers in New Brunswick. It is not sufficient for the SO to request approval of any such proposals simply on the basis that certain market participants have agreed to the proposal.

The Board, as discussed above, will review the revenues and expenses for each of Schedules 1, 2, 3, 5 and 6 on an annual basis. If, as a result of any such review, the Board determines that it would be in the public interest to do so, it will order changes to the method of recovering the approved revenue requirement for any particular service or schedule.

It will be important for existing and new Transmission Customers to have information available as to the likely charges for ancillary services. **The SO is ordered to develop and place on its website historical price information for ancillary services that will provide an indication to Transmission Customers as to what the monthly charges may be in the future.**

The SO stated that a compensation review will be completed over the next few months. In addition, it said that it would provide the final report of Ea Energy Analyses concerning the integration of wind energy. **The SO is ordered to file both the**

compensation review and the Ea Energy Analyses report with the Board once they have been completed.

The Board recognizes that the SO has only been in existence since October, 2004 and that its creation was a fundamental change to the way that electricity is provided in New Brunswick. Such a significant change requires time to properly adapt to the new way of doing things. The SO continues to adapt, to identify its role and to implement the appropriate processes and procedures. The Board recognizes the SO's development to-date and encourages it to continue its progress towards a fully independent self-supporting organization.

The SO is ordered to update the OATT to reflect all of the changes ordered in this decision and to file with the Board, by December 8, 2008, a copy of all pages in the OATT that have changed as a result of this decision.

Summary of decisions made:

Board Authority

The Board finds that it has the authority to approve the use of a mechanism for setting rates as proposed by the SO.

Schedule 1

The Board has reviewed the revenue requirement for 2008/2009 and approves the amount as proposed by the SO.

The Board approves the rates for Schedule 1 that became effective on July 1, 2008, on a final basis. The OATT wording for Schedule 1 services, as found in Attachment "A", is approved.

The SO is ordered to file with the Board, as a minimum, in January of each year, the following information:

The audited financial results for the last full fiscal year;
The budget for the last full fiscal year;
An explanation of all variances between the budget and the audited results for the last full fiscal year;
The projected results for the current fiscal year;
The budget for the current fiscal year;
An explanation of all variances between the budget and the projected results for the current fiscal year;
The budget for the upcoming fiscal year;

An explanation of all variances between the current year projected results and the audited results for the previous year; and

An explanation of all variances between the current year projected results and the budget for the upcoming year.

The above information is to be provided in a format similar to that used in Exhibit A-5, Revised Rates and Charges Section, page 8, Table 1 Financial Schedule – Revenue and Expenses. In addition, the SO is to provide separate reports for each of Schedules 3(a), 3(b), 3(c), 5 and 6 that provide a breakdown of the revenue and expense for each of the Capacity Based Ancillary Services.

The Board orders the SO to have any audited surplus or deficit reviewed by the Board prior to any action being taken with respect to such surplus or deficit. The SO is ordered to file annually with the Board its audited statements, as soon as they are available, together with an explanation of any surplus or deficit for Schedule 1 services.

The Board orders that the wording that was proposed by the SO be replaced with the following:

> "The actual amount of a surplus or deficit for any given fiscal year, as approved by the Board, is to be rebated or billed to Transmission Customers in proportion to their respective Schedule 1 charges for that fiscal year."

The SO is ordered to report each year in January, as part of the annual revenue requirement review process, on any use of the contingency amount during the previous year and to justify the amount of the contingency that is being proposed for the upcoming year.

The Board, subject to the above conditions, approves a change to the method for recovering the costs associated with the provision of Schedule 1 services commencing with the 2009/2010 fiscal year (April 1, 2009). The OATT wording for Schedule 1 services, as found in Attachment “A”, is approved.

Schedule 2

The SO is ordered to file with the Board, in January of each year, information that supports the proposed annual revenue requirement for Schedule 2 and that provides verification that the actual charges to the Transmission Customers, for Schedule 2 services in the previous year, were calculated appropriately.

The OATT wording with respect to possible surpluses/deficits for Schedule 2 services, as found in Attachment “A”, is approved.

The SO is ordered to file annually with the Board its audited statements together with an explanation of any surplus or deficit for Schedule 2 services.

The Board, subject to the above conditions, approves a change to the method for recovering the costs associated with the provision of Schedule 2 services commencing with the 2009/2010 fiscal year.

The Board approves the rates for Schedule 2, as filed on May 1, 2008, effective December 1, 2008. The OATT wording for Schedule 2 services, as found in Attachment “A”, is approved.

Schedules 3, 5 and 6

The Board finds that a change to the OATT that does not clearly specify how the actual charge for each Transmission Customer would be calculated is not just and reasonable. The Board therefore denies the change in methodology for Schedules 3, 5 and 6 as requested by the SO.

Beginning with the 2009/2010 year, the SO is ordered to file annually with the Board its audited statements together with an explanation of any surplus or deficit for each of the Schedule 3(a), 3(b), 5 or 6 services.

The Board approves the rates for Schedule 3(a), 3(b), 5 and 6, as filed on May 1, 2008, effective December 1, 2008. The OATT wording for Schedules 3(a), 3(b), 5 and 6 services, as found in Attachment “A”, is approved.

The Board approves the initial rate of $0.25 per MWh of Wind Energy, effective April 1, 2009. The Board approves, in principle, the escalation of the rate as proposed by the SO.

The SO is ordered to file with the Board, beginning in 2010, as part of the review of the annual revenue requirement, information on the actual revenues, the actual expenses and the expected expenses for the 3(c) service.

The OATT wording for Schedule 3(c) services, as found in Attachment “A”, is approved.

The SO is ordered to provide information, as part of the review for the 2010/2011 fiscal year, on whether or not there should be a limit on the amount of wind power energy that will be eligible to receive 3(c) service.

Cap on Self-Supply of CBAS

The Board denies the requested change and orders that the currently approved cap of 90% remain in effect.

The Settlement Agreement

The SO is ordered to disburse the surplus for 2007/2008 and to treat any surplus or deficit for 2008/2009 in accordance with the Settlement Agreement.

Other Matters

The SO is ordered to develop and place on its website historical price information for ancillary services that will provide an indication to Transmission Customers as to what the monthly charges may be in the future.

The SO is ordered to file both the compensation review and the Ea Energy Analyses report with the Board once they have been completed.

The SO is ordered to update the OATT to reflect all of the changes ordered in this decision and to file with the Board, by December 8, 2008, a copy of all pages in the OATT that have changed as a result of this decision.

Dated at the City of Saint John, New Brunswick this 26th day of November 2008

Raymond Gorman, Q.C., Chairman

Cyril W. Johnston, Vice-Chairman

Donald Barnett, Member

Roger McKenzie, Member

Yvon Normandeau, Member

ATTACHMENT "A"

Effective July 1, 2008

SCHEDULE 1

Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Control Area operator) or indirectly by the Transmission Provider making arrangements with the Control Area operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Control Area operator. The charges for Scheduling, System Control and Dispatch Service are to be based on use of the rates set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

The charges for this ancillary service, payable monthly, are set forth below:

Point-to-Point

1) Yearly Delivery:	One-twelfth of C$2,399.69/MW of Reserved Capacity per year.
2) Monthly Delivery:	C$199.97/MW of Reserved Capacity per month.
3) Weekly Delivery:	C$46.15/MW of Reserved Capacity per week.

4) On-Peak Daily Delivery: C$9.23/MW of Reserved Capacity per day.

5) Off-Peak Daily Delivery: C$6.59/MW of Reserved Capacity per day.

6) On-Peak Hourly Delivery: C$0.58/MW of Reserved Capacity per hour.

7) Off-Peak Hourly Delivery: C$0.27/MW of Reserved Capacity per hour.

Network Integration	C$0.187/kW of Network Integration Service per month.

On-Peak days for the service are defined as Monday to Friday.

On-Peak hours for this service are defined as time between hour ending 09:00 and hour ending 24:00 Atlantic Time, Monday to Friday.

<u>Effective April 1, 2009</u>

SCHEDULE 1

Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Control Area operator) or indirectly by the Transmission Provider making arrangements with the Control Area operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Control Area operator. The charges for Scheduling, System Control and Dispatch Service are to be based on the use of the mechanism set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

The charges for this ancillary service, payable monthly, are set forth below:

Customer Usage/Total Usage x 1/12 of Annual Revenue Requirement where:

(i) Customer Usage is expressed as an equivalent NCP value,
(ii) Total Usage is the sum of all customer usage expressed as an equivalent NCP value, and
(iii) Annual Revenue Requirement is that dollar value for which the Board has granted, each year, approval to the Transmission Provider for recovery with respect to service provided under this Schedule.

Equivalent NCP values are calculated as follows:

Point-to-Point

1) Yearly Delivery:	1.000 equivalent NCP MW per MW of Reserved Capacity per year.
2) Monthly Delivery:	1.000 equivalent NCP MW per MW of Reserved Capacity per month.
3) Weekly Delivery:	0.231 equivalent NCP MW per MW of Reserved Capacity per week.
4) On-Peak Daily Delivery:	0.046 equivalent NCP MW per MW of Reserved Capacity per day.
5) Off-Peak Daily Delivery:	0.033 equivalent NCP MW per MW of Reserved Capacity per day.
6) On-Peak Hourly Delivery:	0.003 equivalent NCP MW per MW of Reserved Capacity per hour.
7) Off-Peak Hourly Delivery:	0.001 equivalent NCP MW per MW of Reserved Capacity per hour.
Network Integration	1 equivalent NCP MW per 1000 kW of Network Integration Service per month.

On-Peak days for the service are defined as Monday to Friday.

On-Peak hours for this service are defined as time between hour ending 09:00 and hour ending 24:00 Atlantic Time, Monday to Friday.

The actual amount of a surplus or deficit for any given fiscal year, as approved by the Board, is to be rebated or billed to Transmission Customers in proportion to their respective Schedule 1 charges for that fiscal year.

Effective December 1, 2008

SCHEDULE 2

Reactive Supply and Voltage Control from Generation or Other Sources Service

In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, generation facilities and non-generation resources capable of providing this service that are in the Control Area where the Transmission Provider's transmission facilities are located are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation or Other Sources Service must be provided for each transaction on the Transmission Provider's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation or Other Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the Transmission Provider.

Reactive Supply and Voltage Control from Generation or Other Sources Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Control Area operator) or indirectly by the Transmission Provider making arrangements with the Control Area operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Control Area operator. The charges for such service will be based on the rates set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by the Control Area operator.

The charges for this ancillary service, payable monthly, are set forth below:

Point-to-Point:

1) Yearly Delivery:	One-twelfth of C$1,613.00/MW of Reserved Capacity per year.
2) Monthly Delivery:	C$134.42/MW of Reserved Capacity per month.
3) Weekly Delivery:	C$31.02/MW of Reserved Capacity per week.
4) On-Peak Daily Delivery:	C$6.20/MW of Reserved Capacity per day.
5) Off-Peak Daily Delivery:	C$4.43/MW of Reserved Capacity per day.
6) On-Peak Hourly Delivery:	C$0.39/MW of Reserved Capacity per hour.
7) Off-Peak Hourly Delivery:	C$0.18/MW of Reserved Capacity per hour.

Network Integration	C$0.125/kW of Network Integration Service per month.

On-Peak days for this service are defined as Monday to Friday.
On-Peak hours for this service are defined as time between hour ending 09:00 and hour ending 24:00 Atlantic Time, Monday to Friday.

<u>Effective April 1, 2009</u>

SCHEDULE 2

Reactive Supply and Voltage Control from Generation or Other Sources Service

In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, generation facilities and non-generation resources capable of providing this service that are in the Control Area where the Transmission Provider's transmission facilities are located are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation or Other Sources Service must be provided for each transaction on the Transmission Provider's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation or Other Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the Transmission Provider.

Reactive Supply and Voltage Control from Generation or Other Sources Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Control Area operator) or indirectly by the Transmission Provider making arrangements with the Control Area operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Control Area operator. The charges for such service will be based on the use of the mechanism set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by the Control Area operator.

The charges for this ancillary service, payable monthly, are set forth below:

Customer Usage/Total Usage x 1/12 of Annual Revenue Requirement where:

(i) Customer Usage is expressed as an equivalent NCP value,
(ii) Total Usage is the sum of all customer usage expressed as an equivalent NCP value, and
(iii) Annual Revenue Requirement is that dollar value for which the Board has granted, each year, approval to the Transmission Provider for recovery with respect to service provided under this Schedule.

Equivalent NCP values are calculated as follows:

Point-to-Point:

1) Yearly Delivery:	1.000 equivalent NCP MW per MW of Reserved Capacity per year.
2) Monthly Delivery:	1.000 equivalent NCP MW per MW of Reserved Capacity per month.
3) Weekly Delivery:	0.231 equivalent NCP MW per MW of Reserved Capacity per week.
4) On-Peak Daily Delivery:	0.046 equivalent NCP MW per MW of Reserved Capacity per day.
5) Off-Peak Daily Delivery:	0.033 equivalent NCP MW per MW of Reserved Capacity per day.
6) On-Peak Hourly Delivery:	0.003 equivalent NCP MW per MW of Reserved Capacity per hour.
7) Off-Peak Hourly Delivery:	0.001 equivalent NCP MW per MW of Reserved Capacity per hour.

Network Integration 1 equivalent NCP MW per 1000 kW of Network

Integration Service per month.

On-Peak days for this service are defined as Monday to Friday.
On-Peak hours for this service are defined as time between hour ending 09:00 and hour ending 24:00 Atlantic Time, Monday to Friday.

The actual amount of a surplus or deficit for any given fiscal year, as approved by the Board, is to be rebated or billed to Transmission Customers in proportion to their respective Schedule 2 charges for that fiscal year.

SCHEDULE 3

Regulation and Frequency Response Service

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing online generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) and by other non-generation resources capable of providing this service as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the Transmission Provider (or the Control Area operator that performs this function for the Transmission Provider). The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation subject to maximum limits established by the Transmission Provider on alternative comparable arrangements. The Transmission Provider shall implement any such limits in compliance with Board policy. The amount of and charges for Regulation and Frequency Response Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass through of the costs charged to the Transmission Provider by that Control Area operator.

The Regulation and Frequency Response Service is comprised of two components. These components are called Automatic Generation Control (AGC) and Load Following and are priced separately below.

Intra-hour performance will be monitored for specific market participant behaviour that introduces a disproportionate burden on the Transmission Provider with respect to AGC and load following. Sanctions may be invoked. The determination of whether or not such activity is disproportionate will take into account the extent to which the offending party is already paying the Transmission Provider for, or self-supplying to the Transmission Provider, the AGC and/or load following services. This determination will give consideration to the net effect of aggregated intra-hour behaviours of Non Dispatchable Generators before any such sanction is invoked.

3(a) AGC: This ancillary service is the provision of generation and load response capability, including capacity, energy and maneuverability, that responds often and rapidly to automatic control signals issued by the Control Area operator.

Effective December 1, 2008, the charges for this ancillary service, payable monthly, are set forth below:

Point-to-Point

1) Yearly Delivery: One twelfth of C$623.04/MW of Monthly Demand per year.
2) Monthly Delivery: C$51.92/MW of Monthly Demand per month.
3) Weekly Delivery: C$11.98/MW of Monthly Demand per week
4) Daily Delivery: C$2.40/MW of Monthly Demand per day

Network Integration C$0.052/kW of Monthly Demand per month

There will be an adder applied to these prices when the Transmission Provider incurs extra costs. These extra costs will be limited to out-of-order dispatch costs associated with revised generation or load dispatch for the purpose of providing this ancillary service.

3(b) Load Following (LF): This ancillary service is the provision of generation and load response capability, including capacity, energy and maneuverability, that is dispatched within the scheduling period by the Control Area operator at frequencies and rates that are lower and slower than AGC.

Effective December 1, 2008, the charges for this ancillary service, payable monthly, are set forth below:

Point-to-Point

1) Yearly Delivery: One twelfth of C$1,440.72/MW of Monthly Demand per year
2) Monthly Delivery: C$120.06/MW of Monthly Demand per month
3) Weekly Delivery: C$27.71/MW of Monthly Demand per week
4) Daily Delivery: C$5.54/MW of Monthly Demand per day

Network Integration C$0.120/kW of Monthly Demand per month.

There will be an adder applied to these prices when the Transmission Provider incurs extra costs. These extra costs will be limited to out-of-order dispatch costs associated with revised generation or load dispatch for the purpose of providing this ancillary service.

3(c) AGC and Load Following for Non-dispatchable Wind Power Generators

This ancillary service is the combination of AGC and Load Following Service required to address the aggregate impact of non-dispatchable wind generation in the balancing area. The rate is inclusive of capacity and out-of-order dispatch costs. The Transmission Provider shall seek to minimize these costs. The Transmission Provider shall discount the rates to the extent that revenues from this service are expected to exceed expenses for the purchase of these services.

Effective April 1, 2009, the rate for this service is: C$0.25/MWh of Wind Energy

This service does not apply to generators that are exporting from the balancing area and for which dynamic scheduling occurs whereby the delivery to an adjacent balancing area is equivalent to the generator's production.

<u>Effective December 1, 2008</u>

SCHEDULE 5

Operating Reserve - Spinning Reserve Service

Spinning Reserve Service (also referred to as Contingency Reserve – Spinning) is needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are online and loaded at less than maximum output and by non-generation resources capable of providing this service. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation subject to maximum limits established by the Transmission Provider on alternative comparable arrangements. Spinning Reserve Service requirements arising from contingencies in excess of an incremental reserve threshold will be the responsibility of parties causing such large contingencies. The incremental reserve threshold shall be established and published by the Transmission Provider. The Transmission Provider shall implement any such limits in compliance with Board policy. The amount of and charges for Spinning Reserve Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass through of the costs charged to the Transmission Provider by that Control Area operator.

The charges for this ancillary service, payable monthly, are set forth below:

Point-to-Point

1) Yearly Delivery: One twelfth of C$1,523.28/MW of Monthly Demand per year
2) Monthly Delivery: C$126.94/MW of Monthly Demand per month

3) Weekly Delivery: C$29.29/MW of Monthly Demand per week
4) Daily Delivery: C$5.86/MW of Monthly Demand per day

Network Integration C$0.127/kW of Monthly Demand per month.

There will be an adder applied to these prices when the Transmission Provider incurs extra costs. These extra costs will be limited to out-of-order dispatch costs associated with revised generation or load dispatch for the purpose of providing this ancillary service. Out-of-order dispatch costs will be calculated as the difference between the cost of serving load and the cost of serving load plus ancillaries. These costs will be charged to Transmission Customers that take this service on a pro rata share basis as a function of the quantity of the service purchased from the Transmission Provider at the time that the out-of-order dispatch occurs.

Supplier Obligations

Transmission Customers that self-supply this service, and third-party suppliers, shall provide between 100 and 110% of the stated MW amount within ten minutes of notification by the Transmission Provider to activate these reserves. The reserves shall be sustainable for sixty minutes from activation.

Activation of Reserves

When a contingency occurs, the Transmission Provider will activate, at its sole discretion, sufficient reserves from (1) those under contract with the Transmission Provider, (2) those provided by Transmission Customers, (3) those contracted from third parties by Transmission Customers. Typically the activation will be done to minimize the overall cost of supplying reserves and to return the system to pre-contingency conditions within the time required by NPCC and NERC.

Effective December 1, 2008

SCHEDULE 6

Operating Reserve - Supplemental Reserve Service

Supplemental Reserve Service (also referred to as Contingency Reserve-Supplemental) is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are online but unloaded, by quick-start generation or by interruptible load or other non-generation resources capable of providing this service. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Supplemental Reserve Service obligation subject to maximum limits established by the Transmission Provider on alternative comparable arrangements. Supplemental Reserve Service requirements arising from contingencies in excess of an incremental reserve threshold will be the responsibility of parties causing such large contingencies. The incremental reserve threshold shall be established and published by the Transmission Provider. The Transmission Provider shall implement any such limits in compliance with Board policy. The amount of and charges for Supplemental Reserve Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

6(a) **Operating Reserve – Supplemental (10 minute)**

This ancillary service is the portion of Operating Reserve – Supplemental that is available within 10 minutes.

The charges for this ancillary service, payable monthly, are set forth below:

Point-to-Point

1)	Yearly Delivery:	One twelfth of C$3,272.64/MW of Monthly Demand per year
2)	Monthly Delivery:	C$272.72/MW of Monthly Demand per month
3)	Weekly Delivery:	C$62.94/MW of Monthly Demand per week
4)	Daily Delivery:	C$12.59/MW of Monthly Demand per day

Network Integration C$0.273/kW of Monthly Demand per month

There will be an adder applied to these prices when the Transmission Provider incurs extra costs. These extra costs will be limited to out-of-order dispatch costs associated with revised generation or load dispatch for the purpose of providing this ancillary service. Out-of-order dispatch costs will be calculated as the difference between the cost of serving load and the cost of serving load plus ancillaries. These costs will be charged to Transmission Customers that take this service on a pro rata share basis as a function of the quantity of the service purchased from the Transmission Provider at the time that the out-of-order dispatch occurs.

Supplier Obligations

Transmission Customers that self-supply this service, and third-party suppliers, shall provide between 100 and 110% of the stated MW amount within ten minutes of notification by the Transmission Provider to activate these reserves. The reserves shall be sustainable for sixty minutes from activation.

Activation of Reserves

When a contingency occurs, the Transmission Provider will activate, at its sole discretion, sufficient reserves from (1) those under contract with the Transmission

Provider, (2) those provided by Transmission Customers, (3) those contracted from third parties by Transmission Customers. Typically the activation will be done to minimize the overall cost of supplying reserves and to return the system to precontingency conditions within the time required by NPCC and NERC.

6(b) **Operating Reserve – Supplemental (30 minute)**

This ancillary service is the portion of the Operating Reserve – Supplemental that is available within 30 minutes.

The charges for this Ancillary Service, payable monthly, are set forth below:

Point-to-Point

1) Yearly Delivery: One twelfth of C$4,054.56/MW of Monthly Demand per year
2) Monthly Delivery: C$337.88/MW of Monthly Demand per month
3) Weekly Delivery: C$77.97/MW of Monthly Demand per week
4) Daily Delivery: C$15.59/MW of Monthly Demand per day

Network Integration C$0.338/kW of Monthly Demand per month

There will be an adder applied to these prices when the Transmission Provider incurs extra costs. These extra costs will be limited to out-of-order dispatch costs associated with revised generation or load dispatch for the purpose of providing this ancillary service.

Out-of-order dispatch costs will be calculated as the difference between the cost of serving load and the cost of serving load plus ancillaries. These costs will be charged to Transmission Customers that take this service on a pro rata share basis as a function of the quantity of the service purchased from the Transmission Provider at the time that the out-of-order dispatch occurs.

Supplier Obligations

Suppliers who offer 30Minute Reserve services shall provide between 100 and 110% of the stated MW amount within thirty minutes of being notified by the Transmission Provider to activate these reserves. These reserves shall be sustainable for sixty minutes from activation.

Activation of Reserves

When a contingency occurs, the Transmission Provider will activate, at its sole discretion, sufficient reserves from (1) those under contract with the Transmission Provider, (2) those provided by Transmission Customers, (3) those contracted from third parties by Transmission Customers. Typically the activation will be done to minimize the overall cost of supplying reserves and to return the system to pre-contingency conditions within the time required by NPCC and NERC.