DECISION

IN THE MATTER OF an Application by Enbridge Gas New Brunswick to change its Small General Service, Mid-General Service, Large General Service, Contract General Service, Industrial Contract General Service and Off-Peak Service Distribution Rates and for approval of its 2012 regulatory financial statements. (Matter No. 225)

April 17, 2014

NEW BRUNSWICK ENERGY AND UTILITIES BOARD

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NEW BRUNSWICK ENERGY AND UTILITIES BOARD:

Chairman:	Raymond Gorman, Q.C.
Vice-Chairman:	Cyril Johnston
Member:	Michael Costello
Counsel:	Ellen Desmond
Chief Clerk:	Kathleen Mitchell

APPLICANT:

Enbridge Gas New Brunswick .L.P.:	Len Hoyt, Q.C. David MacDougall

INTERVENORS:

Atlantic Wallboard L.P.:	Christopher Stewart
Flakeboard Company Limited:	Christopher Stewart
Department of Energy and Mines:	Sacha Patino
Public Intervenor::	René Basque, Q.C. Monica Barley

Introduction

Enbridge Gas New Brunswick Limited Partnership (EGNB) is a public utility, regulated by the New Brunswick Energy and Utilities Board (Board). EGNB is a distributor of natural gas and the general franchisee under a franchise agreement dated August 31, 1999, with the Province of New Brunswick. The distribution of natural gas in New Brunswick is governed by the *Gas Distribution Act, 1999* (GDA).

On October 1, 2013, EGNB applied to the Board to change its distribution rates for the following customer classes: Small General Services (SGS), Mid-General Service (MGS), Large General Service (LGS), Contract General Service (CGS), Industrial Contract General Service (ICGS) and Off-Peak Service (OPS).

EGNB brings this application following a decision of the Board dated July 26, 2013, wherein EGNB was directed to apply for new rates on or before October 1, 2013. The application is made pursuant to section 52 and 56 of the GDA, which was recently amended and which creates a new regulatory context in New Brunswick. This legislation, together with the *Rates and Tariffs Regulation* (Regulation) provide direction on the setting of rates.

Section 52 of the GDA provides, in part, as follows:

> 52(3) The Board may make an order approving or fixing just and reasonable rates and tariffs that a gas distributor shall charge to the classes of customers prescribed by regulation for the distribution of gas or for supplier of last resort services.
>
> 52(5) In approving or fixing just and reasonable rates and tariffs, the Board
>
> (a) shall adopt the methods or techniques prescribed by regulation,
>
> (b) shall not recognize or consider the regulatory deferral account as part of the regulated assets of the gas distributor who was granted a general franchise, except in the circumstances and in the manner prescribed by regulation,
>
> (c) shall not permit the gas distributor who was granted a general franchise to depreciate, amortize, earn a return on or otherwise consider the regulatory deferral account, except in the circumstances and in the manner prescribed by regulation, and
>
> (d) shall not permit the gas distributor who was granted a general franchise to create or establish any additional similar revenue shortfall deferral accounts, except in the circumstances and in the manner prescribed by regulation.

Section 4 of the Regulation currently reads as follows:

> **Rates and tariffs**
>
> 4(1) The Board shall, when approving or fixing just and reasonable rates and tariffs under section 52 of the Act for each class of customers, adopt the cost of service method or technique, with a revenue to cost ratio not exceeding 1.2:1 for any class of customers, provided that the rates and tariffs for any class of customers shall not exceed the rates and tariffs that would apply to that class of customers if determined through the application of the market based method or technique.

It should be noted that this provision of the Regulation has been the subject of litigation. In a decision of the New Brunswick Court of Appeal, dated May 3, 2013, it was determined that the prescribed ratio of 1.2:1 was *ultra vires* the regulation-making authority of the Lieutenant Governor in Council.

The Court of Appeal states as follows at paragraph 11:

> If one looks to the *Act* and the *Regulation*, it is clear the Legislature was addressing itself to two known “methods or techniques” for fixing rates: (1) cost of service; and (2) market based. There may be others. But regardless, the phrase “methods or techniques” cannot be reasonably interpreted to include the right of the LGC to direct the Board to apply, for example, a designated “cost to service ratio”. It may well be true, as suggested by counsel for the Province, that the Board has never exceeded the prescribed ratio of 1.2:1. But that is not a matter relevant to the task of statutory interpretation. The point is simply this. As the *Act* presently reads, it is for the Board to determine what the ratio should be and that is why the directive is *ultra vires* the regulation-making authority of the LGC.

As a result, and as directed by the New Brunswick Court of Appeal, the Board is not bound by the 1.2:1 revenue to cost ratio identified in section 4(1).

Following a decision of the Board dated September 20, 2012, a decision addendum dated September 26, 2012 and a variance to that decision dated July 26, 2013, all rate classes (with the exception of the SGS class) had their distribution rates set using a cost of service method. The SGS class continued to have its rates set using the market based approach.

Following receipt of this application, the Board held a Pre-Hearing Conference on October 28 at which time a hearing process was established. This process allowed for the filing of evidence, interrogatories and responses, motions days and the hearing itself. Three parties registered as intervenors, namely:

- Atlantic Wallboard Inc./Flakeboard Inc. (AWL/FCL);
- The Department of Energy (as observers); and
- The Public Intervenor.

The following witnesses testified at the hearing:

- On behalf of EGNB, Mr. Gilles Volpé, Ms. Lori Stickles, Ms. Susan Toms, Dr. H. Edwin Overcast and Mr. Manuel Monteiro;
- On behalf of AWL/FCL, Mr. John Reed; and
- On behalf of the Public Intervenor, Mr. Robert D. Knecht.

Issues

In this decision the Board will consider the following issues:

- EGNB's 2012 Regulatory Financial Statements, including:
  - Spending
    - Operation and Maintenance (O&M) spending and whether EGNB met the current per GJ target
    - Legal Fees
  - The prudency of system expansion during the year and
  - Whether the Development Period is over

- Approval of Just and Reasonable Rates for each rate class including:
  - EGNB's 2014 Revenue Requirement
  - Cost of Service and Rate Design
  - Market Based Rates including the market based methodology for the SGS class and whether it should be revised
  - Comparison of market based rates and cost of service rates and a determination as to the methodology to be applied in each rate class
  - A determination as to whether all costs are to be recovered from customer classes
  - Rate Riders
  - Minimum Filing Requirements

2012 Financial Statements

EGNB has requested approval of their Regulatory Financial Statements for 2012.

The Board has reviewed EGNB's Regulatory Financial Statements each year since the beginning of the franchise. In the past, the purpose of the annual review was to examine EGNB's spending to ensure such spending was prudent and to determine what, if any amounts, should be added to the deferral account. With the recent legislative changes, the Board is directed not to consider the deferral account as a regulated asset. Nonetheless, the Board considers this financial review to be an important process to determine a number of issues, including whether costs were properly capitalized and whether investments were prudent, as these items affect the 2014 rate base.

O&M spending - per GJ target

One of the largest cost items for EGNB is O&M spending. To measure the effectiveness of this spending, the Board established a "per GJ" or "spending per throughput" target. In 2012, this target was set at $2.55 per gigajoule of delivered natural gas. This target was not revised in 2013 and currently remains the same.

For 2012, total O&M expenses were at approximately the same level as the prior two years. However, it should be noted that the net O&M expenses are substantially higher than in past years, given EGNB's decision to stop capitalizing costs to the development O&M account and to expense all non-incentive sales and marketing expenses each year.

EGNB, in exhibit EGNB 1.10, submits that the actual O&M spending for 2012 was $2.47/GJ and submits that the target has been met for this review period. The Board finds that the target has been met. The Board will continue to monitor this issue in future hearings.

O&M Spending - Professional Consulting

In the last two rate applications, intervenors have taken issue with the cost incurred by EGNB for professional consulting, in particular, legal fees.

As indicated above, the framework for the regulation of natural gas was substantially changed in 2012. As a result of these changes, EGNB was required to make several operational adjustments and professional legal advice was required. Legal fees were paid accordingly.

In addition, EGNB made a decision to challenge the legislative and regulatory changes and commenced civil action seeking damages against the Province of New Brunswick. This civil action is ongoing.

In the Board's decision of September 20, 2012, the Board stated at page 5 as follows:

> The Board accepts that EGNB has an obligation to prepare for legislative changes that may be anticipated and that these costs are properly included the costs of a regulated entity. As a result, those costs incurred in 2011 for professional consulting are approved. Those legal and consulting costs which relate to litigation between EGNB and the province should properly be considered during the review of the years when the expense is incurred.

Legal fees incurred in 2012, related to this litigation, are not approved. The Board will address this issue, when addressing the revenue requirement for 2014. In exhibit EGNB 7.03, EGNB confirms that $814 thousand was spent on this item. These costs are not approved and the 2012 regulatory financial statements will be adjusted accordingly.

The prudency of system expansion during the year

As part of this review process, the Board also examines EGNB's capital additions to ensure that any system expansion was carried out in an economically prudent manner. This analysis is conducted using a system expansion portfolio (SEP) test.

The SEP test is a retroactive consideration of EGNB's capital additions for an historical period, which in this case, is 2012. The test compares the incremental annual revenues that EGNB expects to earn from the new customers it has attached with the incremental annual costs that were incurred in attaching those customers. To be considered prudent, the incremental revenues should exceed the incremental costs by at least 4 percent.

Mr. Knecht, in his evidence, raises one substantive issue with respect to this test. He submits that EGNB incurred a significant amount of capital spending in 2011, which was, at that time, recorded as construction work in progress (CWIP). These amounts were subsequently included in EGNB's property, plant and equipment accounts in 2012 but not included as capital spending for the 2012 SEP test.

Mr. Knecht submits that these CWIP expenditures should be included in the 2012 test and would result in a better match between costs incurred and the customers being attached. EGNB, in its rebuttal evidence, agrees with this modification.

The Board finds that EGNB has passed the SEP test for 2012.

Approval of the 2012 Regulatory Financial Statements

The Board heard no other evidence on the prudency of spending in 2012. The Board will approve the 2012 Regulatory Financial Statements, subject to the adjustment for legal fees as indicated above.

Whether the Development Period is over

Since the beginning of the franchise, EGNB has been considered to be in a Development Period, meaning it is not yet a mature utility. The issue of whether this Development Period is over has been considered in previous rate hearings.

In a decision dated December 1, 2009, the Board provided at page 6 the following criteria for consideration:

> The Board finds that the appropriate criteria to be considered in determining if EGNBLP's Development Period is over are:
>
> Are the full costs equal to or below the currently available revenues?
>
> Are such revenues sustainable?
>
> These tests, to determine if the Development Period has ended for EGNBLP, will be performed each year as part of the annual review process until the Development Period is over. When the Development Period is determined to be over, EGNBLP will no longer be permitted to add to the deferral account.

During cross-examination, EGNB confirmed that, for 2012, they did not recover their full revenue requirement, including their rate of return. Ms. Stickles states as follows at page 331 of the transcript:

> …Well, in 2012, we had a situation where we had caps imposed on our rates so that put us in a situation where revenues did not meet costs. And that took place in October of 2012. And that was a result of the regulation. So it is our contention that rates did not recover costs in 2012 in the pure sense.

In essence, EGNB submits that the costs were “capped” as a result of the regulatory changes and that “full costs” for 2012 were not met, as required in the development period test.

EGNB also filed its budget and forecast financial information for 2013 together with its budget information for 2014. In its forecast for 2013, EGNB indicates that revenues will drop by $7.6 million from 2012 resulting in net income of $8.2 million. This amount falls short of the allowed return of $13.6 million.

In light of the forecasted financial information and the evidence in this proceeding, the Board is not satisfied that the development period is over. The Board will continue to examine this issue during the annual review process.

Application for Rates

The Board will now consider the application for new rates.

As indicated above, the Board is governed by the GDA and the Regulation, which directs how rates are to be calculated. Pursuant to section 4 of the Regulation, the Board is required to:

- Determine the cost of service rate for each rate class;
- Determine the market based rate for each rate class; and
- Use the lower of the resulting rates.

In 2012, when the Board conducted this analysis, all rate classes (with the exception of the SGS class) had their rates set using the cost of service methodology. This was because, when conducting a comparison of both rates, the cost of service rate for most classes was less than the market based rate. For the purpose of this rate application, the Board will again conduct a review of both the cost of service and market based rate for each rate class.

Cost of Service Rates

Revenue Requirement

At the outset it should be noted that, in general, cost of service rates are fixed by determining a revenue requirement for a test year, which in this case is 2014. This revenue requirement is then divided among the customer classes based on a cost allocation study. Once a revenue requirement for each class has been determined, rates for the class are established based on forecasts of throughput.

The revenue requirement is an estimate of the cost of operating the utility, and EGNB has presented its budget for 2014, including EGNB's return on rate base. The Board has carefully considered all of the expense items as presented and the following items require further comment.

O&M Expenses - Pension Expenses

As part of the O&M expenses, EGNB contributes to a pension plan for its employees. This pension plan is a two part plan, with a defined benefit option and a defined contribution option. The cost of this plan, on an annual basis, is approximately $494,100.

For 2014, EGNB indicates that it also required to make a special pension payment, estimated at $715,800. The requirement to make this special payment was explained by Mr. Monteiro, an external pension consultant with Enbridge Inc.

Mr. Monteiro testified that, pursuant to an actuarial valuation, dated December 31, 2012, special pension payments were expected to be made by Enbridge Inc. and its affiliates. These payments were originally expected to be required each year, up to and including 2017. A more recent evaluation, conducted as of September, 2013, now suggests that payments may conclude in 2015.

Intervenors took issue with this special payment and whether recovery in the revenue requirement is appropriate. Referring to a decision by the Ontario Energy Board, Case No. EB 2011-0277 dated May 10, 2012, and relying on the rationale provided therein, Mr. Stewart suggests that there is no obligation for EGNB to offer employees non-contributing pension benefits. He suggests that EGNB voluntarily assumed this obligation and also assumed the risk and responsibility for funding this plan. Mr. Stewart submits that the Board should not allow this cost to be recovered in the revenue requirement.

The Board has carefully considered the decision described above. This decision involves a case where Enbridge Gas Distribution Inc. made a request for recovery of a pension deficit based on specific criteria that had been defined and which were applicable to "z" factor adjustments in the context of performance based regulation. The factors in the

Ontario Energy Board case, referred to by Mr. Stewart, are not the same factors in this application.

The Board is also aware of another Ontario Energy Board decision, Case No. EB 2011-0354 dated November 2, 2012, wherein Enbridge Gas Distribution Inc's budgeted pension expenses were approved for that year and included in the utility's revenue requirement.

There is no question that the pension costs, including the special payment, are a large amount of money and requires careful management by EGNB. Ongoing efforts to manage this expense are required. For 2014, the Board finds that the cost of the pension plan, including the special payment of $715,800 is a prudent expense. The Board is satisfied that the payment is necessary and forms part of the compensation package paid to EGNB employees.

O&M Expenses - Payments to Affiliates

EGNB makes payments to affiliated companies, as a result of Service Level Agreements (SLAs) and a corporate allocations policy; both of which have been carefully considered by the Board in past rate applications. In each case, EGNB is required to demonstrate how these costs would be incurred if EGNB was a stand-alone operation and how these costs currently benefit ratepayers in New Brunswick.

Of particular interest in this hearing were changes made to the SLA's and corporate allocations policy since 2012. These adjustments were the subject of interrogatories, undertakings and subject to cross-examination. Having considered all of the evidence, the Board will comment on the following items that warrant particular attention. The Board finds that:

1) Four IT accounts, namely *Acquisitions, IT security, IT Planning and Governance, and Public Web Systems*, are appropriate allocations and should be recoverable at 100% from the revenue requirement;

2) *Corporate IT Operations* has been discontinued and should not be included in the revenue requirement;

3) *Benefits and Pensions* should not be included in the revenue requirement, as indicated in 2012;

4) *Corporate General Expenses* should be referred to and considered as *Corporate General Law Expenses*; an allocation approved by the Board in 2012 and which is recoverable at 25% from the revenue requirement;

5) *Executive VP People and Partners* (previously referred to as Group VP Corporate Resources) should not be included in the revenue requirement as this was disallowed in 2012. This will result in an adjustment of $5,376 in the revenue requirement;

6) *Directors Fees*, pursuant to an SLA ,were inadvertently overstated and should be reduced in the revenue requirement by $68 thousand;

7) *Compliance Group Law and Group VP Law* are new allocations. EGNB submits that the main focus of these law departments will be on implementing policies on an enterprise wide level, with the effect of ensuring good governance and the consistent application of standards. EGNB submits that an allocation of 50% is appropriate. Mr. Knecht recommends that recovery of these allocations should be at 25%, which is consistent with how the Board has treated corporate legal costs in the past. The Board agrees with Mr. Knecht and sets these allocations at 25%.

8) *Executive Risk Insurance* is insurance which mitigates the personal responsibility of EGNB's representatives. This allocation was approved in 2012 but the methodology for calculating this allocation was more recently modified, resulting in an increased allocation to EGNB in the amount of $111 thousand. Mr. Knecht, in his evidence, submits that while Enbridge now allocates this cost based on the number of directors, one would expect that personal responsibility risk would be more related to the overall size of the business. Mr. Knecht recommends that the increased cost of the executive risk insurance be excluded from the revenue requirement. The Board agrees with Mr. Knecht and an adjustment of $111 thousand is ordered.

All other allocations will be approved.

O&M Expenses - Professional Consulting

As part of its revenue requirement, EGNB has included $3.012 million for professional consulting. This is an increase of almost $1 million over 2013 and the principal reason for this increase is due to legal fees. In particular, EGNB has forecast a cost of $1.1 million for legal fees related to two actions by EGNB against the Province of New Brunswick.

EGNB submits that, to the extent they are successful with the litigation, damages related to the deferral account will, to the extent available, be used to defray the deferral account. EGNB submits that benefits will flow to the ratepayers and therefore the cost of pursuing this litigation should be included in the revenue requirement.

Intervenors took issue with the inclusion of these fees in the revenue requirement. Mr. Knecht, in his evidence, states as follows at page 10:

> In general, legal costs that are a necessary component of providing service to ratepayers are included in a utility's revenue requirement.
>
> The costs in question, however, appear to relate to a legal challenge to provincial legislation. From my (non-legal) perspective, I do not consider these costs to be a necessary component of providing gas distribution service to ratepayers, and conclude that they should not be included in the revenue requirement.

Mr. Stewart, in his cross examination, also challenged these legal fees and whether any value will flow to the ratepayer. During closing arguments, Mr. Stewart submits, in part as follows at page 637 of the transcript:

> "…Equally I would suggest that it is crucial for Enbridge Gas New Brunswick to create a connection between this litigation and the benefit to ratepayers.."

Continuing at page 642 of the transcript, Mr. Stewart submits:

> Once again, Mr. Chairman, members of the panel, we would submit that there is no benefit to the ratepayers in this legal case, it is none of our business, we shouldn't be asked to pay for it. The results will be what the results will be and that may, in the Board's discretion in the future, have a benefit or an effect for ratepayers or it may not. The tie that Enbridge tries to make to this litigation and the benefit of the ratepayers is too tenuous, too remote to have found an obligation to ratepayers to pay those amounts. \

The Board is not satisfied that, at this time, there is an identifiable benefit for the ratepayer arising from the ongoing litigation. The current legislation does not allow the deferral account to be recognized as an asset to be included in the rate base. It is not clear that pursuing recovery of the deferral account through litigation will provide a benefit to the customers of EGNB. While the Board is not commenting on the value of the litigation or EGNB's decision to pursue the same, the Board does not allow the legal fees associated with this litigation to be included in the revenue requirement for 2014.

O&M Expenses - Capitalization and Amortization

The Board has, in past reviews, carefully considered EGNB's capitalization rates and policies.

For 2014, EGNB proposes changes to the capitalization of construction and maintenance costs, sales costs and marketing costs. No party took issue with the change in capitalization of construction and maintenance costs and the Board approves this change.

There have been significant changes in the capitalization of sales and marketing expenses in recent years.

By way of example, in 2012, EGNB decided to eliminate incentives and expense all non-incentive sales and marketing costs. In 2013, following a capitalization study, this was revised, with non-incentive sales being capitalized at 37.46 % and marketing costs at 8.70%.

A further study was conducted and the numbers for 2014 have been revised again; now with sales being capitalized at 88.8 % and marketing at 94%.

EGNB indicates that there have been significant changes made to their sales and marketing team together with the creation of a new communications department. Because of the nature of the expenses the Board will deal with sales separately from marketing.

EGNB indicates that sales expenses are related to staff in the sales department. The sales department's activities are directly related to attaching new customers. Given that these customers will generate future revenue, the Board accepts the change in the capitalization of the sales expense.

The marketing expense for 2014 reflects two separate changes. EGNB proposes an increase in the budget by approximately $570 thousand dollars. The second change is that EGNB proposes to capitalize a significantly larger portion of this expense.

In its rebuttal evidence, at Exhibit 10.01, EGNB submits that marketing costs will now be directed at research and promotions, aimed at understanding the current market and barriers to natural gas conversion. EGNB submits that expenditures will be incurred, with the goal of creating interest and awareness around natural gas.

While operational changes may be required, it is also necessary to consider these proposed changes in light of EGNB's submission that they do not expect significant growth in customer attachment or load. There is no clear evidence that the expenditures on marketing will directly translate into customer additions.

The Board has carefully considered the marketing costs and the proposed capitalization rates. The Board accepts the EGNB evidence that it needs to spend more money on research in 2014 to develop a marketing strategy for its new business model.

Recognizing that EGNB is attempting to develop a new long term marketing strategy in 2014, both the amount and the level of capitalization for marketing is approved. The Board would not anticipate that such a significant marketing expense would be capitalized at these levels on an ongoing basis.

Contract Demand Revenue

For certain classes of customers, including CGS and ICGS, a contract demand charge is established when distribution service is first provided. As indicated by Mr. Reed in his evidence at Exhibit AWL-FCL 1.01 at page 16, the contract demand is generally an agreed-upon amount that is intended to represent the customer's maximum daily usage and entitlement on the system. In most jurisdictions, if a customer exceeds the agreed-upon amount, the contact demand can be "ratcheted up" causing the customer to incur penalties and/or overrun charges.

Similarly, in EGNB's case, the tariff provides that when a customer exceeds their contract demand, they may be subject to a ratchet provision. EGNB may increase the contract demand for the remainder of the contract year and apply that demand charge retroactively for the portion of the contract year that has expired to date.

In addition, EGNB also conducts an annual review, to determine if the contract demand for each customer is appropriate. This annual review was historically conducted in August of each year. For 2013, the annual review was not conducted until October.

Two issues have been identified by AWL/FCL with respect to the contract demand charge. AWL/FCL submits that while EGNB did conduct its annual review in 2013, retroactive charges in accordance with the ratchet provision were not applied to ICGS customers. This resulted in a revenue loss in 2013 of approximately $260,000. Moreover, ratchet provision monies have been collected most years. Given the consistency with which these funds have been recovered, an amount of $260,000 should be included as revenue in the revenue requirement for 2014.

In addition, because the annual review was conducted later than usual, the new contract demand for each customer was not set before the filing of this rate application. If contract demands had been adjusted, AWL/FCL contend that there is another $260,000 in additional income to be accounted for in the 2014 budget.

While AWL/FCL was most concerned with the ICGS class, the application of the ratchet provision and the annual setting of the contract demand, also applies to the CGS customers.

EGNB, through the hearing process and in response to undertakings, attempted to address these concerns. With respect to the decision to not apply a ratchet provision in 2013, Mr. Hoyt submitted as follows at page 578 of the transcript:

> In EGNB's response to undertaking number 2, EGNB explained that it had consciously not applied the ratchet clause to any customers in the ICGS or CGS classes between October 1, 2012 and September 30, 2013, because following the enactment of the Rates and Tariffs regulation, all customers were moved into new rate classes. That is why EGNB did not charge the $260,000, as calculated by Mr. Stewart, to ICGS customers or the $96,000, as calculated in EGNB's response to undertaking number 2 to CGS customers….

Continuing at page 579, Mr. Hoyt submits:

> And any money that EGNB could have collected as a result of the ratchet provision in 2013 is money that EGNB left on the table. It has no impact on the test year revenue requirement and EGNB did not apply the ratchet for the principal reason set out in undertaking number 2.

The Board accepts the submission that the ratchet provision was not applied in 2013, given the legislative changes that were underway. In addition, the Board notes that the ratchet provision is intended to deter customers from exceeding its contract demand charge. It is, in effect, a penalty that customers should be attempting to minimize as much as possible. The Board finds that it would be inappropriate to budget for revenues in 2014 that may arise from the application of the ratchet provision.

With respect to EGNB's annual review of the contract demand charge, the Board is concerned with the inconsistent practice that has developed in the calculation of this charge. Mr. Reed, at Exhibit AWL-FCL 1.01 page 18, submits that this practice has resulted in an inexplicable relationship between the contact demand level and the design peak day allocator that is used in the Cost of Service Study. This, in turn, results in cross subsidies within the rate class. Moreover, failing to review the contract demand in a consistent fashion results in a less reliable forecast of throughput and a less reliable budget.

In this case, the contract demand charge should have been updated prior to the filing of the rate application. Historically the review was done in August of each year. Failing to conduct the review in August of 2013, resulted in revenue being excluded from the 2014 forecast of revenue which will impact the result rates. While AWL/FCL contend that the revenue adjustment should be $260,000, Ms. Stickles testified that the difference in revenue would be approximately $226,000. The Board directs that the revenue forecast be adjusted to properly account for the updated contract demand information. EGNB is to provide supporting calculations for the adjustment in the revenue forecast.

Conclusion - Revenue Requirement

The Board has carefully examined all of the projected expenses for 2014. Having considered all of the evidence and submissions by the parties, the Board accepts the costs presented by EGNB with the exception of those items adjusted above.

Subject to the changes set out above, the Board approves the 2014 Revenue Requirement.

Allocation of Costs

The second step in the determination of cost based rates is the allocation of costs. The revenue requirement, as approved above, must be allocated among the customer classes.

In the case of EGNB, the rate classes are established in section 3 of the Regulation and are as follows:

1) Small General Service (SGS);
2) Mid-General Service (MGS);
3) Large General Service (LGS);
4) Contract General Service (CGS);
5) Industrial Contract General Service (ICGS);
6) Off-Peak Service (OPS); and
7) Contract Power Plant Service (CPPS)*

**As was the case in 2012, no evidence was filed for the CPPS class because there are no customers in this class.*

Section 4 of the Regulation directs the Board (except when applying a market based rate) to "adopt the cost of service method or technique". The "cost of service method or technique" is specifically defined in the Regulation as follows:

> "cost of service method or technique" means the method or technique of approving or fixing rates and tariffs based on the cost of providing distribution services in accordance with generally recognized utility regulatory principles and practices.

In most instances, when setting cost of service rates, it is generally accepted that cost of service studies are used as a guide to determine how much of the utility's revenue requirement should be recovered from each class.

In this case, EGNB did file a cost of service study, proposing a division of costs amongst the prescribed customer classes. This study, marked as Exhibit EGNB 5.08, is an update to the study filed with the Board in August 2012, which was fully reviewed and considered during the last rate hearing. In its decision of September 26, 2013, the Board made a number of fundamental decisions, based on expert opinion and reflective of recognized utility regulatory principles. The updated cost of service study, Exhibit EGNB 5.08, is consistent with these fundamental decisions.

Both Mr. Knecht and Mr. Reed made suggested modifications to the cost of service study. In particular, Mr. Reed testified that ICGS customers should be allocated costs based on their contract demand, and not on the peak day demand allocator, used by EGNB.

The Board has carefully considered the evidence of both the Public Intervenor and AWL/FCL. Many of the issues identified in their reports were considered by the Board in the previous decision. As a result, the Board is not prepared to modify the Cost of Service Study at this time and as such, the Board approves the Cost of Service Study as proposed by EGNB.

Determination of Cost Based Rates

Having approved the Cost of Service Study, the next step is to establish the average revenue per GJ that will be necessary to meet the revenue requirement for each class. These rates are arrived at by dividing the total cost allocated to each class by the forecasted throughput for that class.

With respect to throughput for the SGS class, Mr. Knecht takes issue with the estimated customer additions for 2014. Mr. Knecht suggests that the forecast for 2014 appears to be pessimistic and that a more reasonable approach would be to use the actual results from 2013.

In 2013, EGNB attached approximately 241 new SGS customers. Of these 241 new customers, 71 had signed up in 2012 and for which ENGB had committed to pay an incentive. This incentive program has now been discontinued. While EGNB has increased its sales and marketing costs for 2014, these monies are aimed at creating interest and awareness around natural gas and to promote future growth of the utility. EGNB notes that this will not translate directly into customer additions.

The Board accepts EGNB’s forecast of SGS customer additions and throughput as proposed by EGNB. The Board also accepts the estimated forecasted throughput for all other classes.

In its initial evidence EGNB filed estimated cost of service rates based on its proposed revenue requirement and its proposed cost of service methodology. These rates can be found in Exhibit EGNB 1.02. These rates must be compared with the market based rates described below.

Determination of Market Based Rates

As with the cost of service rates, the Board is directed in section 4 of the Regulation to also determine the market based rate for each customer class. These rates are determined by considering the "market based method or technique" which is defined as follows:

> market based method or technique means the method or technique of approving or fixing rates and tariffs based on the principles generally adopted by the Board before January 1, 2012 in relation to the holder of the general franchise.

From the beginning of the franchise until the Regulation came into effect, the Board set "market based rates" using a market based formula. This formula was the prime determinant of distribution rates for all customers. The formula was designed with two goals in mind. The first goal was that customers would experience sufficient savings, in comparison to an alternate fuel, to choose natural gas and remain on the system. The second goal was to permit EGNB to recover as much revenue as possible during its development period.

To achieve savings, the formula was designed to allow a typical customer to achieve a set percentage savings target (target savings) on the combined delivery and natural gas costs (burner tip price). To calculate the target savings, it is necessary to forecast the cost of both the alternative fuel and natural gas over the next 12 months.

In Exhibit EGNB 5.03, EGNB has filed a calculation showing the market based rate for each prescribed rate class. This filing is generally consistent with the methodology used in past rate hearings. For all rate classes, with the exception of the SGS class, no changes to the methodology have been made.

There is, however, one significant difference. In this case, EGNB has requested that a fundamental change be made to SGS calculation, so to better reflect the customer composition of this class. To understand the rationale for this requested change, it is useful to first examine the history and evolution of the SGS class.

Prior to the recent legislative changes, a number of rate classes existed and in each case, the market based formula was calculated in a slightly different fashion. The design of each class was intended to permit the application of the market based methodology. For example, there was a "residential oil class" of customers and EGNB would calculate the cost of their alternative fuel, i.e. furnace oil, to determine the appropriate target savings for this group of customers. For the “residential electric” customers, EGNB would calculate the cost of electricity as the alternative fuel, and again determine the appropriate level of target savings. The formula used for the small commercial customers was again, slightly different. In each case, the goal was to provide customers with a certain level of savings so as to encourage continued growth of the natural gas system in New Brunswick.

In 2009, following a Review of a Cost of Service Study, the Board approved a number of new rate classes, designed specifically to be used once EGNB began charging cost of service rates. These classes are not well suited for market based rates, which, as described above, consider a number of inputs and depend on the type of customer converting to natural gas.

In 2012, when significant legislative changes were being made, the Regulation adopted the customer classes, approved by the Board and intended for use in a cost of service regime. In effect, all residential oil, residential electric and small commercial customers were placed into one customer class.

In addition, section 4(2) of the Regulation prescribes how the market based formula will now apply to this combined group of customers. Section 4(2) states, in part, as follows:

> 4(2) In determining rates and tariffs for classes of customers under subsection (1) utilizing the market based method or technique, the Board shall use electricity as the alternative energy source and ensure a target savings level of 20% for the Small General Service class.

EGNB submits that the market based formula should now be adjusted to better reflect the customers in this class. EGNB describes this change as follows at page 2 of Exhibit EGNB 5.00 as follows:

> EGNB has proposed a change to the methodology for establishing the market based rate for the Small General Service class, to reflect the two distinct types of customer that fall within this class. The SGS class, which uses electricity as the alternative energy source, consists primarily of residential customers, but also includes a large number of commercial customers. NB Power rates differ significantly for residential and commercial customers. EGNB is proposing that the market base rate for the Small General Service class be calculated based on a blended electricity cost derived using a weighted average based on the residential and commercial customer count within the class.

The proposed use of the "blended electricity cost" was of significant debate during the hearing. In its last rate application, EGNB used a "residential electricity cost" as the alternative energy source and this provided a target savings of 20% for all *residential* customers. At the same time, using the residential electricity cost resulted in larger commercial customers, who are also members of the SGS class, recovering savings far in excess of the targeted 20%. In essence, the blended composition of this class resulted in some customers achieving savings far greater than was intended.

In this application, EGNB has modified the inputs to the formula so that the electricity rate now reflects the rate used by both residential customers and commercial customers. EGNB submits that the proposed modification, and the use of a "blended electricity cost" not only meet the constraint of the Regulation, but also limit the amount of revenue that needs to be collected from the other rate classes. In addition, this approach keeps the SGS rate closer to its allocated cost and allows rates to be competitive.

In contrast, the Public Intervenor submits that the "blended rate" should not be used. He submits that EGNB has promised residential customers a 20% discount from their alternative fuel and that "target savings" are part of the value proposition offered to customers when converting to natural gas. In this instance, using a "blended electricity rate" will result in many residential customers not achieving a target savings of 20%.

EGNB was specifically asked, on cross-examination, about how many of the residential customers in the SGS class will in fact achieve a target savings of 20%, using the new blended approach. In response to this question, EGNB states as follows at page 316-317 of the transcript:

> The savings projected for the residential members of the SGS class is approximately 8 percent. I am going on memory here for the SGS class, the commercial component of that class, it was somewhere in the vicinity of 30 odd percent and I can certainly provide a more accurate number if need be, but that's about where it was. So on average the class saves 20 percent but of course within the class we know there is always customers who save more or less than they target…

In essence, EGNB submits that while the *residential* customer may not achieve a target savings of 20%, the *typical customer* in this class will be able to achieve the savings required by legislation. Using a blended approach and providing the *typical customer* with the required target savings, results in a distribution rate of $11.14/GJ. If EGNB were to use the residential electricity rate in its calculations for the alternative fuel, a distribution rate of $8.20/GJ would result.

In determining whether to accept EGNB's proposal on this point, the Board must be mindful of its legislative obligation. As indicated in section 4 of the Regulation, the Board is directed to: "…ensure a target savings level of 20% for the Small General Service class".

As indicated, the target savings level is for the *class*, not for individual members of that class.

At the same time, the Board is directed by Regulation to use the market based method or techniques that had been in place by the Board, prior to January 1, 2012. Traditionally, when applying the market based method, the Board would be concerned as to whether a significant portion of the customers in any given class would receive their target savings. The issue now before the Board is that there is both a "typical" residential customer and a "typical" small commercial customer; each with different consumption levels and different usage profiles.

The language used in section 4 of the Regulation, together with the language used in the definition of "market based method or technique" requires the Board to balance the interests of the parties. In this case, while the blended approach meets the technical requirements of section 4, it does not meet the full objectives of the market based system. Specifically, it does not necessarily produce rates which will attract and retain residential customers. The Board is concerned that few residential customers in the SGS class will in fact receive the target savings they had anticipated when converting to natural gas. Many *residential customers* will not see a 20% savings as compared to the alternative fuel.

As a result, and to balance these competing interests, the Board will set the rate for the SGS class at $10/GJ. A rate of $10/GJ will better meet the original objectives of the market based system and will allow a greater number of residential customers in the SGS class to achieve their target savings and still reflects the principles generally adopted by the Board when applying market based rates.

In addition, EGNB is directed to re-examine how the SGS rate will be set in the future. Clearly the composition of the members in this class creates a difficulty in accomplishing the stated legislative and regulatory objective. Several alternatives were discussed during the hearing process. The most practical solution would be to subdivide the customers in the SGS class into two sub-classes, so to permit the Board to apply two different rate designs. The subclasses will, in turn, be more homogeneous. The evidence provided in the hearing did not provide sufficient data for the Board to fully develop this option. As a result, EGNB is directed to develop a proposal, reflecting a division of the SGS class into sub-classes, so that this issue can be resolved. In the event EGNB wishes to propose an alternative solution, in addition to the one described herein, the Board will consider the same.

It is anticipated that EGNB will be filing for new rates, effective 2015. This proposal is to be filed at the time of that rate application, or within the next six months, whichever is sooner.

The rates arising from the application of the market based formula or technique for all rate classes, with the exception of the SGS can be found in Exhibit EGNB 1.02.

Approval of Rates

Comparison of market based rates and cost of service rates

Having considered both the average cost of service and market based rate for each class, the Board is now required to conduct a comparison of the resulting rates. In its filed evidence, EGNB provided an estimate of these rates for consideration.

Exhibit EGNB 1.02 provides as follows:

	Market Based	Cost based
SGS	$12.8722	$25.7648
MGS	$16.1088	$9.4381
LGS	$15.8295	$5.3665
CGS	$10.8536	$3.7036
ICGS	$14.0659	$2.2334
OPS	$12.0816	$1.8587

These rates are not precise and cannot be determined until EGNB re-files its revenue requirement and adjusts the cost allocation under the approved Cost of Service study. However, it is clear that the cost of service rates for all classes except the SGS class will be lower than the comparative market based rate. The SGS class distribution rate is set at $10/GJ. As indicated earlier in this decision, the $10/GJ rate reflects the required balance, between providing savings to customers while allowing EGNB to maximize its revenues.

It is important to note that the rates generated by both the cost of service study and the market based formula represent the total costs per GJ to the customers and that in the rate design process these amounts will be allocated to customer charges, demand charges and delivery charges according to the rate design for each class.

Rate Design

Rate design is a process of fixing rates so to promote the efficient use of the natural gas distribution system. A number of tools can be used. These include dividing the revenue-per-GJ required into monthly charges, demand charges, different seasonal rates as well as tiered delivery charges. The use of these tools reduces the intra-class subsidization while balancing the need for easy to understand rates.

EGNB filed its proposed rate design for all regulated classes. Little debate took place with respect to the proposed rate design of the SGS, MGS, LGS, CGS and OPS classes. The Board approves the rate design filed by EGNB with respect to these customer classes.

Rate Design - ICGS

Significant debate took place with respect to the rate design of the ICGS class. AWL/FCL suggests that costs should be allocated differently than proposed by EGNB. They submit that smaller customers impose significantly different costs on a system than higher load factor and larger customers. These cost differences are not fully captured in the existing rate design because the demand charge does not capture all of the demand related costs. A higher demand charge, with lower customer and distribution charges, would better reflect cost causation.

AWL/FCL also submits that EGNB's proposed seasonal break-out for the ICGS class should be reviewed and that EGNB should return to a tiered rate structure with declining block rates to reflect the lower level of unit costs that are imposed by larger customers.

Similarly, Mr. Knecht, in his evidence agrees that any increase in the distribution rate should be more reasonably spread among the demand and energy charges. In his view, a demand charge increase is more consistent with cost causation than is an energy charge increase. Mr. Knecht points out that this issue applies, not just to ICGS but to CGS customers as well.

Dr. Overcast, in his rebuttal evidence, agrees with a shift towards a higher demand charge (or fixed charge) stating as follows at page 13:

> It is my preference to recover all of the fixed costs for larger customers in fixed charges. I believe this is a reasonable goal for EGNB to move toward recognizing that doing so will have impacts on the cost for lower load factor customers that must be carefully managed to avoid rate shocks. Nevertheless this is a useful goal over the next few rate proceedings. In this case, it is not inappropriate to move more revenue to the demand charges in both schedules.

The Board agrees that a shift towards a higher demand charge is appropriate at this time. This shift, however, must be managed gradually, so as to avoid rate shock for smaller customers within the ICGS class.

The Board orders that the demand charge be set at $18 per GJ for the ICGS. The Board also orders that EGNB consider adjusting the demand charge for CGS customers so to begin a shift towards a higher demand charge, recognizing the principles of both cost causation and gradualism.

The Board approves the following Rate Design for the following classes:

1) SGS: There will be a customer charge of $16 per month, no contract demand charge, and a per GJ delivery charge for all volumes delivered.

2) MGS: There will be a customer charge of $50 per month, no contract demand charge, and a two-tiered delivery charge. The first tier will cover the first 100 GJs of natural gas delivered each month. The second tier will be for amounts in excess of 100 GJs.

3) LGS: There will be two customer charges – one of $125 for customers with maximum consumption of up to 650 GJs in a month and for customers with maximum consumption of greater than 650 GJ in a month the customer charge shall be $225. There will be no contract demand charge. There will be a two tiered delivery charge. The first tier will be for the 250 GJs delivered per month. For volumes of natural gas delivered in excess of 250 GJs per

month there will be a Winter Rate (delivered between September 1 and April 30) and a Summer Rate (delivered between May 1 and August 31).

4) CGS: There will be no customer charges, the contract demand charge will be $13.30 per GJ of Contract Demand. There will be a Winter Delivery rate for volumes delivered between September 1 and April 30 and a Summer Delivery rate for volumes delivered between May 1 and August 31.

5) ICGS: There will be a customer charge of $3,300 per month. There will be a contract demand charge of $18 per GJ of Contract Demand. There will be a Winter Delivery rate for volumes delivered between September 1 and April 30 and a Summer Delivery rate for volumes delivered between May1 and August 31.

Determination as to whether the shortfall in revenue from the SGS class is properly allocated to other rate classes and to what extent

Given the above noted rates and the approved rate design, it is clear that all rate classes with the exception of the SGS class are paying their full cost of service. This means that the revenue generated from the SGS rates does not cover the costs incurred to serve this class of customers.

At the same time, EGNB has a revenue requirement that has been fully vetted and approved. If EGNB is to recover its full revenue requirement, other rate classes must contribute to the revenue shortfall incurred in the SGS class. The extent to which other customer classes should be required to make up the revenue shortfall, was explored in detail in both the evidence and during cross-examination.

The extent to which a particular customer class is obligated to subsidize other customer classes is often analyzed by the use of revenue to cost ratios. A revenue to cost ratio is defined as the total revenue over the total cost for that particular customer class. For example, a class where the revenue precisely equals the costs, would have a revenue to cost ratio of 1.0.

Mr. Reed, in his evidence, states as follows at page 10:

> ..I do not believe that a cost ratio of greater than 1.2 is appropriate for the ICG class and I recommend that the Board fully evaluate whether it is appropriate for any customer class

> to be above that level. In my 37 years of experience in utility ratemaking, I have to say that it is quite uncommon to ask any firm service rate class to pay a rate that is materially above the COS. Certainly there are exceptions to this general rule, but the rule remains generally applicable nonetheless. In my experience, utilities work diligently to try and align revenues and COS and to achieve a revenue to cost ratio as close to possible to 1.0.

Dr. Overcast took a very different position. He submits that revenue to cost rates do not provide a measure of fairness of rates between various classes. He indicates that there are many considerations that impact on cost of service including how the class is defined, how costs are being allocated and whether there are cross-subsidizes within the class. With various factors for consideration, the determination of cost allocation is at the discretion of the Board.

Dr. Overcast also submits that a comparison should not be made between the revenue to cost ratio of mature utility and to that of a greenfield utility. He notes that more mature utilities have scale economic benefits and lower unit costs that help to maintain lower revenue to cost ratios.

In essence, the Board must now determine if EGNB should have the opportunity to recover its full costs or if this opportunity should be constrained in some fashion; either because the resulting rates will be unjust, the resulting revenue to cost ratio for certain classes may be intolerable, the constraints of the market require lower rates or for some other similar reason.

At the outset, the Board is mindful of its statutory obligation. Pursuant to section 52 of the GDA, the Board must set rates that are just and reasonable. At the same time, rates for all classes must be set in accordance with the Regulation. These legislative provisions direct the Board and fundamentally determine the framework for the calculation of rates. The Board is also guided by other indicators, including revenue to cost ratios, the concept of a utility's fundamental risk and the realities of market pricing, all of which assist the Board in its determination of rates. Undoubtedly the Board is faced with competing principles which creates a fine balance between the interests of the utility and those of the customer.

In previous decisions, particularly in the electricity sector, the Board has noted the importance of revenue to cost ratios. In a decision of the Board dated June 19, 2006, the Board stated as follows with respect to Disco's rates at page 46:

> …The Board considers that it is appropriate for the 2006/07 year that each class have a revenue to cost ratio of at least 0.95. Establishing this minimum ratio will reduce interclass cross-subsidies and allow rates to provide a price signal that will lead to more efficient use of electricity.

In a decision of the Board dated February 22, 2008, again dealing with Disco's rates, the Board noted at page 29-30:

> ..The principle, that customers should pay their fair share of the cost of the electricity they use, is well established and generally not disputed. The Board has stated that a reasonable range for revenue to cost ratios is .95 to 1.05 and urged DISCO to move its rates so that all of the customer classes were within that band.

While the Board has recognized the importance of revenue to cost ratios, rate classes in the electricity sector have been well outside the rage of 0.95 to 1.05. This continues to be the case, even though Disco (now NB Power) is a long standing, mature utility that has been using cost of service rates for some time.

Moving to reasonable revenue to cost ratios is important to send appropriate price signals. Yet, for EGNB, the ratios have to be considered in light of the fact that one rate class is still in a market-based system. Since the SGS customers are not paying full cost of service rates, other rate classes, by necessity, will have a revenue to cost ratio above 1.0. Any consideration of revenue to cost ratios has to be made in light of the hybrid system under which EGNB operates.

At the same time, there is long standing jurisprudence which has determined that utilities must be provided with the opportunity to recover its approved revenue requirement. As indicated in the seminal case of *Northwestern Utilities Ltd. v. Edmonton (City), [1929] S.C.R.186,* rates that are just and reasonable allow recovery of the expenses incurred together with a fair return on the investment devoted to the enterprise. This is an extremely high priority and critical to the ongoing operation of the utility. This principle must be respected, if at all possible, when setting just and reasonable rates.

Finally, and as stated above, the Board has made a finding that EGNB is still in the development period. Both market and cost based rates are being used. Sustainable revenues have not yet been achieved. In addition, EGNB has submitted and the Board has approved a substantial sales and marketing budget, which has the objective of promoting the awareness of natural gas.

With these concepts and principles in mind, the Board will not reduce the 2014 Revenue Requirement for the purpose of setting rates, other than for the adjustments noted above. The Board is satisfied that the resulting revenue to cost ratios are currently appropriate for a developing utility. The Board finds the rates for all classes to be just and reasonable.

At the same time, EGNB is directed to work towards a more closely aligned revenue to cost ratio for each customer class. This is a reasonable objective, particularly as EGNB moves into full cost of service rates and becomes a mature utility.

Rate Riders

The use of rate riders has been an important part of the market based method or technique since the conception of the EGNB franchise. As indicated above, the market based method has, at its core, the objective of providing savings to customers, while allowing EGNB to maximize its revenues.

Rate riders were developed to allow EGNB to adjust rates below the maximum approved rate to ensure that the target savings were maintained. Rate riders were designed as an expedited process, providing EGNB with the flexibility to adjust to market conditions. In the past, when a rate rider was put in place, any shortfall in revenue would be added to the deferral account. Now, without a functioning deferral account, the mechanism for recovery no longer exists.

In this application, EGNB has requested that rate riders be discontinued. Mr. Volpé submits that, since the deferral account is no longer available, EGNB does not have the tools to react to the market place and adjust the distribution rates on a weekly or monthly basis. Rates have been proposed by EGNB that allow for a target savings of 20% for the SGS class, based on the inputs calculated at the time of the application. EGNB does not propose to vary the rate at any time during the forecast period, even if there are significant changes in the market place.

Mr. Volpé states as follows at page 288 of the transcript:

> It's a different world then it was back then. We used to have---EGNB used to have a deferral account and a variance account to capture the shortfalls…..

> ….So without the rate---sorry, without the deferral account or a variance account or a methodology that allows you to increase rates for the cost customers, that is not painful, then the system doesn't work. Back when this was implemented we had—all rate classes were on market based designations. And now we have a hybrid model where we have a larger number of our customers and the majority of the rate classes are on cost of service. We have one rate class which is on market based. And the same can't apply because- unless we are all okay. And I don't think any of us are with having cost of service rates that yo-yo though-out the year to match the rate rider implementation for the SGS rate class. I don't think anybody wants that. So this is a different era. It is a different world with different rules. And the same expectations can't apply.

Mr. Knecht, in contrast, submits that rate riders should be retained. Mr. Knecht submits that, as market conditions change, SGS customers may face circumstances in which their target savings are substantially less than the 20% target. This would make it more difficult for EGNB to meet the legislated target and would reduce EGNB's ability to market new customers.

Mr. Knecht also submits that the rate rider should be "bi-directional" in nature, which would allow the SGS rate to both increase and decrease, when the commodity price changed. This "bi-directional" variance could be instituted in conjunction with a variance account, which could capture shortfalls over time.

From a review of previous Board decisions, wherein the issue of rate riders has been considered, two observations can be made:

1) Rate riders are a tool, provided to EGNB, so that market pricing can be flexible. With the exception of the most recent rate rider, imposed by the Board in February, 2014, EGNB has had the discretion to determine when to apply for a rate rider; and

2) Rate riders are intended to ensure that distribution rates remained competitive. If market conditions are such that natural gas is not a competitive energy source, EGNB is expected to respond and adjust rates accordingly.

As indicated above, the SGS class is the only class of customers still on market based rates and the composition of this class has changed dramatically since 2012. The Board has directed EGNB to re-examine the SGS class and a rate of $10/GJ has been put in place until the class is better defined to work within a market based system.

Until the SGS class has been redefined, it is difficult to determine if natural gas continues to be a competitive energy source for these customers. Redefining the SGS class may, in effect, result in a situation where rate riders no longer have a useful role.

The Board will not require EGNB to implement a rate rider, pending the filing of a new SGS class composition. Since rate riders are suspended and may be eliminated, EGNB will be required to make annual rate filings, including a filing for 2015 rates. Any necessary adjustment to SGS rate can be made at that time.

With respect to the rate rider that was imposed in February 2014, any revenue shortfall between February and May will not be recovered in this test year. The rate rider mechanism was still in place for the SGS class and an adjustment was both necessary and appropriate at that time.

Minimum Filing Requirements

Parties were asked to comment on the creation of minimum filing requirements for future rate applications.

EGNB noted that it supports a review of the current level of information being filed with the Board, with the view of improving the efficiency of the regulatory process. Mr. Stewart noted that additional rate design data is necessary and referred the Board to minimum filing requirements published by the Ontario Energy Board. Similarly, Mr. Knecht made a number of suggestions as to the information that should be contained in any rate filing.

The Board has carefully considered the submissions of the parties. EGNB is ordered to propose minimum filing requirements to the Board at a date to be set by the Board.

Board Orders

The Board makes the following orders:

- EGNB shall re-file its revenue requirement in accordance with this decision.

- EGNB shall re-file the approved Cost of Service Study using the updated revenue requirement.

- EGNB shall re-file updated rate schedules in accordance with this decision.

- EGNB shall comply with all of the above orders on or before April 25, 2014.

- The Board will issue an order approving or fixing rates and tariffs on April 28, 2014, which shall take effect May 1, 2014.

Dated at the City of Saint John, New Brunswick this 17 day of April , 2014.

Raymond Gorman, Q.C., Chairman

Cyril W Johnston

Cyril Johnston, Vice-Chairman

Michael Costello

Michael Costello, Member