DECISION

IN THE MATTER OF an Application by Enbridge Gas New Brunswick Limited Partnership, as represented by its general partner, Enbridge Gas New Brunswick Inc., for approval to change its Small General Service distribution rates for 2018 and 2019 and for approval of its 2016 Regulatory Financial Statements.

(Matter No. 371)

December 13, 2017

NEW BRUNSWICK ENERGY AND UTILITIES BOARD

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NEW BRUNSWICK ENERGY AND UTILITIES BOARD:

Chairperson:	Raymond Gorman, Q.C.
Members:	Patrick Ervin
	John Patrick Herron
Counsel:	Ellen Desmond, Q.C.
Chief Clerk:	Kathleen Mitchell

APPLICANT:

Enbridge Gas New Brunswick Limited Partnership:	Len Hoyt, Q.C.

INTERVENERS:

Arauco North America:	Christopher Stewart
Public Intervener:	Heather Black

A. Introduction

[1] Enbridge Gas New Brunswick Limited Partnership, as represented by its general partner, Enbridge Gas New Brunswick Inc. (EGNB), filed an application with the New Brunswick Energy and Utilities Board (Board) seeking changes to distribution rates for the Small General Service (SGS) customer class for 2018 and 2019. EGNB proposes that changes to SGS distribution rates take effect on January 1, 2018 and on January 1, 2019, respectively. There is no request to change distribution rates for non-SGS classes, for reasons set out below.

[2] EGNB is also seeking approval of its 2016 Regulatory Financial Statements and approval of a revised Handbook of Rates and Distribution Services.

[3] On December 16, 2016, amendments to the *Gas Distribution Act, 1999* (Act) became effective. Revisions of particular relevance to the current application are summarized as follows:

a) The 2017 rates and tariffs that were approved by the Board in relation to all customer classes other than SGS are subject to a rates and tariffs freeze until December 31, 2019, subject to certain provisions that may impact non-SGS rates between 2018 and 2020. (s. 52.07)

b) The *Rates and Tariffs Regulation* (NB Regulation 2012-49), which formerly prescribed customer classes and methods by which the Board was required to determine rates and tariffs, was repealed.

c) The Board is required to recognize the regulatory deferral account (established by a Board order dated June 23, 2000) in the amount of $144.5 million. No portion of that account shall be included in the revenue requirement for the years 2017 to 2019 inclusive. (ss. 52(5)(c), 52.01 and 52.02)

d) For the period from January 1, 2017 to December 31, 2019, no amounts shall be credited towards the balance in the regulatory deferral account, subject to certain conditions. (ss. 52.03(1))

e) For the purposes of fixing rates and tariffs for 2018 and 2019, the Board shall permit a return on equity of 10.9%. (s. 52.05)

f) EGNB is required to file with the Board an application for approval of rates and tariffs for the SGS customer class, covering the period from January 1, 2018 to December 31, 2019. (ss. 52.06(1) and (2))

g) The Board is required to approve an increase in the variable portion of the SGS rates, as approved by the Board for 2017, by 3% effective January 1, 2018 and by 3%

effective January 1, 2019. This is subject to conditions that may impact SGS rates in 2018 or 2019. (s. 52.06(3))

[4] Although not all of the revisions are currently applicable to this application, the revisions to the Act may have a future impact on the 2018, 2019 and future customer rates, and on the ability of EGNB to apply credits to the regulatory deferral account.

[5] For example, if EGNB's 2017 year-end results in an actual return on equity in excess of 10.9%, any excess up to 200 basis points shall be credited to the regulatory deferral account. Any excess beyond 200 basis points would be equally split between a credit to the regulatory deferral account and a reduction in EGNB's revenue requirement for 2018, which would be applied to decrease the rates for one or more non-SGS classes. The same would apply in relation to 2018 and 2019 year-end results.

[6] Rates otherwise in effect in 2018 and 2019 could also be impacted if the Board, at any time during those years, approves an average increase of greater than 3% in residential class electricity rates. In such an event, the Board would be required to order a similar increase in the SGS rates and resultant reductions in one or more non-SGS class rates.

B. Issues

[7] This decision addresses the following issues:

1. Approval of the 2016 Regulatory Financial Statements;
2. Approval of the 2018 and 2019 Budgets;
3. Approval of SGS distribution rates for 2018 and 2019; and
4. Other issues as set out in this Decision.

C. Analysis

1. 2016 Regulatory Financial Statements

[8] In its decision dated November 30, 2016 in Matter 330, the Board indicated that an evaluation of the Board's ongoing retrospective financial reviews is warranted. The amended Act now requires retrospective reviews to determine the disposition of any returns in excess of 10.9% during the years 2017 to 2019. In addition, the SEP test, discussed below, is based on retrospective reviews.

For these reasons, the Board will continue to conduct retrospective reviews for the foreseeable future.

a. O&M Expense Ratio

[9] The Board sets an annual Operations and Maintenance (O&M) expense ratio target, based on EGNB's budgeted O&M expense (before transportation costs), and its projected throughput. A ratio target was originally required to determine the ability of EGNB to add to its deferral account.

[10] In Matter 306, the Board approved a 2016 net O&M budget of $12.14 million and a forecasted throughput of 6,002 terajoules (TJs). The resulting target was $2.02 per gigajoule (GJ). Based on the 2016 actual results of $10.69 million O&M expense (before transportation costs) and 5,515 TJs of throughput, the O&M expense ratio was $1.94 per GJ, which is within the target.

[11] The Board is of the view that a retrospective O&M ratio test no longer serves a useful purpose, considering that the Act does not permit any additions to the regulatory deferral account. The Act establishes the balance of the regulatory deferral account at a specified amount, and governs any reductions. EGNB is no longer required to present an O&M ratio test as part of a retrospective financial review.

b. SEP Test

[12] The Board also assesses the prudency of system expansion related capital expenditures as part of its retrospective review. The Board established a system expansion portfolio (SEP) test in its decision of May 16, 2011.

[13] In order to pass the SEP test, the annualized revenues from system expansions in a year must exceed the depreciated expansion capital costs by at least 4% (or a ratio of 104%). Failing this test could result in the Board reducing EGNB's rate base by an amount that would be required to pass the test.

[14] The 2016 SEP test failed. Under the current method, the ratio is 78%, based on incremental revenues of $413 thousand and incremental costs of $532 thousand. A reduction of $1.266 million in the total capital expansion cost would be required to attain a ratio of 104%.

[15] A revised method was submitted by EGNB, using only those capital costs tied directly to customers included in the revenue portion of the test. Under this method, 19 expansion projects in 2016 would be removed from capital, reducing the capital spend, for SEP test purposes, by

$1,124 million, which would reduce incremental costs to $428 thousand. This would still fail the SEP test, but with a ratio of 97%.

[16] EGNB argued that the SEP test is but one factor in assessing prudent capital spending, and that failing the test is not an automatic indicator of imprudent expansion. It maintains that it has spent prudently in 2016 for the benefit of the system. In its submission, the primary reason for not passing the test was because of where EGNB was in its growth life cycle. It cited earlier legislative constraints and competition from alternative fuels, leading to fewer customer attachments. In its argument, it suggested that the wording of the Board's more recent SEP test evaluations imply a flexible approach.

[17] EGNB also explained that "timing quirks" can affect SEP test results, which could be mitigated by using multiple year data. EGNB referred to several alternative approaches to the current SEP test as being more appropriate to evaluate the prudency of system expansions.

[18] Mr. Robert Knecht, in evidence filed by the Public Intervener, agreed that EGNB's revised method of matching revenues and costs is a sound accounting and economic principle. He acknowledged that there are alternative methods of evaluating the prudence of capital spending that could be considered for future purposes. Mr. Knecht stated however, that any change in the SEP test method should only be applied in future reviews, and not in relation to the 2016 results.

[19] The Board agrees that the SEP test should be applied without modification to the 2016 financial statements in a manner that is consistent with its earlier decisions. There was nothing in the evidence or argument that would necessitate a departure from the regulatory model first adopted in 2011.

[20] The result of the SEP test is the reduction of the 2016 expansion capital additions from $4.994 million to $3.728 million, a difference of $1.266 million in its rate base. EGNB is directed to make this reduction in its 2016 regulatory financial statements and to refile the statements for Board approval. Regulatory financial statements for later years will also reflect this modification.

[21] If EGNB wishes to propose modifications to the Board's method of evaluating the prudence of expansion projects, it should file a proposal in a future application.

2. 2018 and 2019 Budgets

[22] The Board's fixing or approval of just and reasonable rates is typically founded in part upon its determination and approval of the utility's revenue requirement for a future test year. The current application does not follow this pattern. Subject to certain provisions, the Act establishes 2018 and 2019 rates. Although EGNB has presented its proposed budgets for those years, any Board

determination concerning those budgets would have no impact, in this decision, upon 2018 or 2019 rates. Later contingencies, as mentioned at the outset of this decision, could however impact such rates.

[23] Despite this, the budgets inform the Board of EGNB's consumption forecasts and spending plans for the years in question. These will be compared, with any variance explanations, with eventual financial results. This, in turn, will assist the Board in its determinations of EGNB's revenue requirements and just and reasonable rates for 2020 and beyond.

a. Non-Residential Retention and Propane Winback Programs

[24] Given that distribution rates are prescribed for 2018 and 2019, amounts budgeted on the Non-Residential Retention and Propane Winback Programs will have no impact on rates for those years.

i. Non-Residential Retention Program

[25] The Non-Residential Retention program budgets for 2018 and 2019 are $100,000 and $50,000, respectively. The 2016 actual expense for the program was $85,000 (17% of the $500,000 budget) and the 2017 forecast is $50,000 (50% of the $100,000 budget). The details of the program are the same as those reviewed by the Board in prior rate applications (formerly referred to as the commercial customer retention program).

ii. Propane Winback Program

[26] The Propane Winback program proposed for 2018 and 2019, has budgeted spending of $100,000 and $50,000, respectively. Its aim is to recapture eligible customers who had left the system in favour of propane. EGNB explained that the program will target strategic lost accounts which have a positive payment history and offer a large revenue potential. A payback period of one year or less is part of EGNB's criteria.

[27] When questioned about the need for such a program in light of trending increases in propane pricing, EGNB pointed out that some incentives would assist to cover certain re-conversion costs. The program would also be retained as insurance against propane market downswings.

b. Incentive Programs

[28] The Residential Incentive Program and the newly-proposed Commercial Incentive Program are part of the capital budgets for 2018 and 2019. Although spending in 2018 and 2019 will have no impact on rates in those years, it will be added to the rate base, and amortized.

[29] EGNB acknowledged during testimony that the payback periods for these incentive programs depend upon the resulting amount of additional consumption. EGNB is treating these as a form of market testing over the next two years, to determine their effectiveness at customer attraction.

i. Residential Incentive Program

[30] The Residential Incentive Program provides an incentive of up to $2,000 to SGS customers, depending on expected consumption and equipment. The 2016 and 2017 budgets were $100,000 each. Actual spending for those years were $88,000 and $41,000 (to September 8, 2017).

[31] Program spending in 2018 is budgeted at $100,000 to attract 40 new customers and 20 customers considering adding new load. In 2019, the $250,000 budget is aimed at 100 new customers and 50 existing customers with additional load.

[32] The Board approves the continuation of the Residential Incentive Program, but directs that the projected payback period for any individual incentive payment must be no longer than fifteen years for new loads and no longer than five years for existing customers adding equipment and load.

ii. Commercial Incentive Program

[33] The Commercial Incentive Program is budgeted at $250,000 in 2018 and $500,000 in 2019. It is designed to attract 20 new customers and 40 new customers, respectively, and to attract new load from existing customers. Payment of an incentive is made after the additional load is added, and is based on a set of parameters.

[34] The Board approves the Commercial Incentive Program, but directs that the projected payback period for any individual incentive payment must be no longer than fifteen years for new loads and no longer than five years for existing customers adding equipment and load.

c. Retention and Incentive Program Reporting

[35] In Matter 306, EGNB was directed to file quarterly reports to the Board in relation to incentives paid under the commercial customer retention program, now referred to as the Non-Residential Retention program. The Board now directs EGNB to expand the quarterly reports to include the Residential Incentive, the Commercial Incentive and the Propane Winback programs. The report will include details of amounts expended, and the annual revenues retained or regained resulting from the expenditures. The Board will review these reports to assess their ongoing effectiveness.

d. Revision of Budgets

[36] EGNB filed its 2018 and 2019 budgets, as Exhibit EGNB 6.01. As a result of the Board's determination to reduce the 2016 rate base in paragraph 20, adjustments to the budgets are necessary. EGNB is directed to file revised 2018 and 2019 budgets accordingly.

3. Distribution Rates for 2018 and 2019

a. SGS Distribution Rates

[37] Based on the revisions to the Act as outlined above, the Board must approve 2018 and 2019 rate increases for the SGS class of customers as described below.

[38] Sub-sections 52.06(1) and (2) of the Act requires EGNB to file an application for Board approval of rates for the SGS class of customers. Sub-section 52.06(3) directs that the Board shall approve an increase in the variable portion of the SGS rates, with respect to the rates approved by the Board for 2017, by 3%, effective January 1, 2018 and 3%, effective January 1, 2019. The Board-approved variable portion of the SGS rates for 2017 is $9.4450/GJ.

[39] The above requirement is subject to subsection 52.06(4) of the Act, which would apply if the Board were to approve a rate increase for residential electricity rates of more than 3% during the above-mentioned period. In such an event, the Act requires the Board to order a similar increase to SGS rates, and a corresponding decrease in EGNB's revenue requirement, which would be applied to reduce the rates of one or more non-SGS classes, as proposed by EGNB.

[40] In accordance with these provisions, EGNB filed for approval of the variable portion of SGS rates for 2018 and 2019. The Board finds that the proposed rates are consistent with the requirements of the Act.

[41] In accordance with the Act, and subject to any adjustments required under subsection 52.06(4), the Board fixes the variable rates for the SGS customer class as follows:

a) $9.728, effective January 1, 2018; and

b) $10.020, effective January 1, 2019, to remain in effect until December 31, 2019.

b. Other Classes Distribution Rates

[42] EGNB's application in this matter does not seek an order to fix or approve rates for any class other than SGS. Section 52.07 of the Act imposes a rates and tariffs freeze in relation to the rates

and tariffs approved by the Board for non-SGS classes for 2017, to remain in effect until December 31, 2019.

[43] Accordingly, the Board is making no order with respect to the rates and tariffs for the Mid-General Service (MGS) Class, Large General Service (LGS) Class, Contract General Service (CGS) Class, Industrial Contract General Service (ICGS) Class and Off-Peak Service (OPS) Class. Those rates as were previously approved by the Board for 2017 will therefore remain in effect until December 31, 2019.

[44] The non-SGS rate freeze is, however, subject to two exceptions that may reduce rates for one or more classes. First, there may be reductions under subsection 52.06(4), where, as described above in relation to the SGS rates, the Board approves a residential electricity rate increase higher than 3%.

[45] Second, subparagraph 52.03(2)(b)(ii)(B) of the Act requires one-half of any 2018 or 2019 returns exceeding 12.9% to be applied to reduce the revenue requirement for one or more non-SGS classes in the following year, with corresponding rate decreases and rebates, if applicable.

[46] The Board will deal with these contingencies, if and when they occur.

c. Rate Schedules for 2018 and 2019

[47] The Board approves the Rate Schedules for 2018 and the Rate Schedules for 2019, as filed with the Board as Schedules 5.1 and 5.2 of EGNB's evidence (Exhibits EGNB 1.19 and EGNB 1.20). EGNB's Handbook of Rates and Distribution Services shall be revised according to any rate changes as and when appropriate.

[48] EGNB is directed to file an application for 2020 rates for all classes in sufficient time for the Board to approve rates to be effective as of January 1, 2020.

4. Other Issues

a. Load Retention Proposal

[49] The Board has previously endorsed the concept of a load retention program (described as "flex rates" in previous decisions) as a potential benefit in cases where competitive fuel options for large commercial customers could result in significant load losses to the distribution system. In Matter 306, the Board directed EGNB to commence a stakeholder process to establish the parameters of such a program, and to file proposed program details for Board approval.

[50] A Load Retention Proposal was filed by EGNB as Section 6.0 in this proceeding (Exhibit EGNB 1.21). There was stakeholder agreement on a number of items, but questions remained concerning the treatment of revenue shortfalls resulting from a retention rate.

[51] The proposal sets out parameters and a process leading to an application for Board approval. A load retention rate would be available to the ICGS rate class only, and would only become available following the expiry of the legislated rate freeze. The resulting revenue shortfall would be held in a variance account, to be fully recovered from all customers on a volumetric basis.

[52] Mr. Knecht's filed evidence provides an assessment of the proposal. He generally agrees with the practice of a "flex rate mechanism" to allow utilities to respond to competitive threats. He does not believe that Board pre-approval is necessary, beyond an initial application process, which would establish Board rules and determine whether Board pre-approval is necessary on an ongoing basis.

[53] There should be no reconciliation, in Mr. Knecht's opinion, of any revenue shortfall during the period between the commencement of a retention rate and the next general rate application. For the interim period, a shortfall should be borne by the utility, not by rate payers. In his view, this provides the utility with greater motivation to diligently negotiate with a customer seeking a retention rate.

[54] Mr. Knecht also stated that, assuming a rate freeze precludes the adoption of flex rates before 2020, the Board's consideration of the Load Retention Proposal should be deferred until an initial application is made. At that stage, he stated, "…circumstances may be very different, come late 2019…" at which time a better evaluation may be made.

[55] Arauco generally supports EGNB's proposal. In his submission, Mr. Stewart stressed the importance of having a Board approved load retention protocol in place as part of the Board's decision in this matter.

[56] Mr. Stewart also agreed with EGNB that any interim shortfalls should be borne by ratepayers, on the basis that the retention of loads and the preservation of revenues that are in jeopardy benefit the system as a whole. The onus would be on EGNB to later convince the Board of the longer term benefits of any retention rate at the next general rate hearing.

[57] In the Public Intervener's final submission, Ms. Black agreed that it would be best to have a retention rate process in place, prior to the Board's consideration of an application. Ms. Black maintained, however, that any consequential interim revenue shortfalls should be borne by the utility. Finally, Ms. Black submitted that there is no real benefit to having a pre-approval process, particularly if there is to be no consideration of interim recovery from ratepayers.

[58] It is a generally accepted regulatory principle that rate discounts to retain customers are reasonable, in circumstances where it is shown that the system as a whole benefits by retaining loads that would otherwise be lost.

[59] One of the requirements of the Load Retention Proposal is that it must be shown that retaining a customer's load at a retention rate is "better for the natural gas distribution system including the utility than losing the customer in question." This would be a key factor in the Board's consideration of an application.

[60] Subsection 52(1) of the Act and section 60 of the *Energy and Utilities Board Act* require an order or approval of the Board to charge for the distribution of gas or to change any tariff. These provisions apply to a proposal to charge a load retention rate.

[61] Paragraph 52(5)(b) of the Act also allows the Board to recognize a regulatory variance account as part of EGNB's regulated assets.

[62] The Board approves the provision by EGNB of a Load Retention Program to the ICGS customer class, subject to the following conditions:

a) the load retention rate parameters, the joint application process and the customer application process, shall be as set out in pages 2 – 4 of the Load Retention Proposal as filed by EGNB as Section 6.0 (Exhibit EGNB 1.21) of its application;

b) the Board will consider an earlier application, but no load retention rate shall be effective prior to January 1, 2020;

c) subject to b), a load retention rate shall apply to the customer as of the next billing cycle following the Board's approval;

d) revenue shortfalls as a result of a load retention rate shall be recorded by EGNB in a Load Retention Variance Account (LRVA);

e) amounts recorded in the LRVA shall be included in the revenue requirement for EGNB's next fiscal year.

[63] At the next rate application, following the Board's approval of a load retention rate, the Board will determine, *inter alia*:

a) the allocation of LRVA amounts among rate classes;

b) whether the circumstances requiring a load retention rate continue to apply to any applicable customer, and if so, determine a process for the Board's ongoing review of such circumstances;

c) whether any further revenue shortfalls as a result of the load retention rate will continue to form part of EGNB's revenue requirement; and

d) whether the LRVA will be recognized as part of EGNB's regulated assets.

b. 2017 Regulatory Financial Statements

[64] The next rate application is not anticipated until mid-2019 for the 2020 test year. EGNB has proposed that the 2017 retrospective financial review occur by way of a written proceeding, with the filing of the 2017 regulatory financial statements and related reports by April 30, 2018.

[65] The Board directs EGNB to file its 2017 regulatory financial statements and related evidence on or before April 30, 2018. The Board will decide the hearing method and schedule following such filing.

c. Handbook of Rates and Distribution Services

[66] In Matter 330, the Board directed EGNB to review its customer service policies and to make the necessary changes and updates to its Handbook of Rates and Distribution Services (Rate Handbook), to be filed with the current matter.

[67] EGNB's evidence includes the January 1, 2017 version of its Rate Handbook, with proposed revisions to the current version indicated. EGNB seeks the Board's approval of a new version, based on the revisions. EGNB submits that the revisions are not substantive, and do not impact the rates charged to customers. They are therefore not affected by the legislated rate freeze in 2018 and 2019 for non-SGS customers. The Board accepts this argument.

[68] EGNB acknowledged in its interrogatory responses to the Public Intervener and Board staff, that certain additional revisions or corrections are required. In satisfaction of an undertaking, EGNB also provided revised language relating to meter tests in Appendix B of the Rate Handbook. During Board Counsel's questions at the hearing, EGNB acknowledged several other areas of the Rate Handbook that would benefit from clearer language.

[69] The Board accepts the revisions to the Rate Handbook as set out in Section 7.0 of EGNB's application (Exhibit EGNB 1.22), subject to the inclusion of the Appendix B language as set out

in Exhibit EGNB 6.02. With those inclusions, the Rate Handbook is hereby approved, to be published by EGNB and dated as of the date of this decision.

[70] EGNB is directed to consult with Board staff and the Interveners for the purposes of identifying further non-substantive revisions to the Rate Handbook, including, but not limited to those identified in the interrogatory responses and during the hearing. EGNB is directed to file a proposed revised Rate Handbook resulting from these consultations as part of its application for approval of its 2018 regulatory financial statements.

d. Rate Class Review and Assignment

[71] EGNB uses historical loads in its annual customer rate class review. Based on 12-month loads to the end of September, non-SGS customers may be moved to a different customer class as of November. In Matter 330, the Board directed EGNB to evaluate a suggestion by Mr. Knecht that using weather-normalized loads for annually assigning non-SGS customers to rate classes would be more accurate or stable.

[72] EGNB filed its analysis as Schedule 3.10 (Exhibit EGNB 1.13) in this matter. A total of 390 customers were moved to another rate class as a result of its October 2016 review. Using a weather-normalized approach for the same period, 310 customers would have been re-allocated. In response to an interrogatory, EGNB also provided an analysis for the previous year. It produced similar results, with 332 customer moves, versus 279 moves using a weather-normalized approach.

[73] Although the weather-normalized evaluation resulted in fewer class changes, EGNB points out that it would have, for the period in question, resulted in fewer customers moving to a lower per GJ rate class. It also submitted that the weather-normalized consumption approach is less transparent to re-allocated customers, which, unlike the current method, cannot be validated by the customer reviewing its monthly billings.

[74] The Board agrees that the current annual historical load method of re-assigning non-SGS customers to a different rate class is preferable to adopting a method based on weather-normalized loads. The simplicity and transparency of the current method for affected customers reduces any customer confusion following the November billing cycle.

Dated in Saint John, New Brunswick, this 13th day of December, 2017.

Raymond Gorman, Q.C.
Chairperson

Patrick Ervin
Member

John Patrick Herron
Member