SECTION 7.0

Rate Design

7.0 Rate Design

Enbridge Gas New Brunswick (EGNB) continues to operate in the development period as a start-up public utility facing numerous unique challenges as compared to traditional gas LDCs. One of those challenges is found in addressing cost of service and rate design within the variety of constraints posed by the extent of its competitive markets, legislation and the regulatory compact. To understand the rate design proposals presented by EGNB, it is necessary to begin with a discussion of these constraints and how they interact to adversely limit the range of rate design options. This report consists of three sections: Section One: The Rate Design Background, Section Two: Rate Design Tools and Issues and Section Three: Proposed Rate Designs for 2015.

Section One: The Rate Design Background

To understand the background for rate design this report begins with the well-known concept of the regulatory compact as discussed in the filing for rates last year. The regulatory compact can be summarized as a series of rights and obligations that represent the implied contractual relationship between the regulated public utility and the regulatory authority.

OBLIGATIONS	RIGHTS
Obligation to serve.	Right to a reasonable return.
Provide safe and reliable service.	The provision of service is subject to reasonable rates, rules and regulations.
Charge non-discriminatory rates.	Receive protection from competition.
Charge just and reasonable rates.	Right of eminent domain.

None of these obligations are unlimited in the sense that the terms of service and rules and regulations place limits on the extent of the obligations through such things as line extension policies or policies related to shutting off customers for non-payment. As the list illustrates, there are significant rights and obligations related to the issue of rate design. In this list the obligations to provide non-discriminatory rates and to charge just and reasonable rates are imposed by the regulatory authority through the rate case process. Similarly the rates approved by regulation must satisfy three rights. First, the rates approved must provide the utility with a reasonable opportunity to earn a return that is consistent with returns earned by the market for entities with similar risks, i.e. the reasonable return. Second, the rates need to be reasonable including recovering the revenue requirement and producing residual revenues after prudently incurred costs sufficient to reward shareholders for the risk of the investment and to allow the utility to attract capital on reasonable terms. Third, the rates must allow the utility to provide competitive services at competitive prices while still satisfying the two previous rights. EGNB has the difficult task of proposing rates that protect these rights but in addition must satisfy legislative mandates that make this task very difficult.

Where some customers have competitive options, the regulator is not relieved of the obligation to allow the utility an opportunity to earn the allowed return through rates that in total recover the cost of service including a reasonable return. Essentially, this means that the rate revenues from competitive customers plus the rate revenues from captive customers must equal the total revenue requirement or the cost of service.

The issue of reasonable rates for customers who have no economic option to taking service from the utility is neither new nor novel. The concept has been discussed in economics literature and in regulatory decisions under several different descriptive terms such as “Constrained Market Prices” or “Constrained Differential Pricing”. As noted above, these concepts have been applied in a number of regulatory settings. For example, the Interstate Commerce Commission, the predecessor regulatory agency to the Surface Transportation Board, discussed the concept of CMP as a basis for establishing reasonable rates for captive shippers. In doing so they established three clear standards for assessing a reasonable level of rates: (1) revenue adequacy for the company; (2) management efficiency for the service provided; and (3) the Stand Alone Cost (SAC) test. These three tests represent fundamental rights and obligations of the regulator and the utility.

Among the binding constraints are the legislative mandates that residential rates be based on a target annual discount of 20% below the delivered cost of electricity. The essential problem with this mandate is that it assumes that most customers have switched from electric service to gas. The evidence is that almost twice as many residential customers switched from oil to natural gas. Based on data for the twelve months ended February 2014, 5418 customers switched from oil to natural gas and 2810 switched from electricity. This different impact in switching is not surprising given that the capital cost of switching is higher for electric customers and electric costs are typically lower than the cost of oil, giving natural gas a more competitive advantage relative to oil. By setting the competitive rate by regulation, EGNB is forced to provide much larger benefits for oil customers than is warranted by competitive considerations. In providing these extra benefits, other customers must make up for the shortfall in revenue requirements that impose additional risks on other classes of service. In addition, by forcing the public utility to use the rate rider provision, the Energy and Utilities Board ("Board) made it impossible to recover the actual revenue requirement during the rate effective period for 2014. Implementing the rate rider resulted in much lower rates for most residential customers who continued to receive large benefits even absent the rate rider. Effectively under the interpretation in the 2014 rate order, the rate rider is no longer a just and reasonable provision because it is a one way adjustment that causes rates to produce inadequate returns. By definition, inadequate returns do not satisfy the just and reasonable standard.

Significantly, there is no opportunity under rates that are commodity based for EGNB to have an opportunity to earn its allowed return. This occurs because rates are designed on the basis of normal weather and a forecast of test year volumes that may or may not be achieved. As actual weather varies from normal weather, EGNB's return is either higher than allowed when weather is colder than normal or lower than required when weather is warmer than normal. The end result of significant fixed cost recovery through volumetric rates is a level of revenue stability that makes capital attraction difficult. Historically, EGNB had available a deferral account that made it indifferent to weather, forecast error and the impact of the rate rider. Changes in regulation have eliminated this tool so that EGNB is adversely impacted by both the rate rider and the commodity based recovery of fixed costs. Ultimately, EGNB is faced with the problem of constrained optimization for recovery of its revenue requirements such that significant changes must occur in the definitions of rate classes and the design of rates. Further, it will be necessary to consider additional rate design tools such as full decoupling of rates from volumetric recovery of fixed costs and that decoupling must occur in real time without deferral accounting.

The issue of competitive markets is noted above in part by the residential dilemma of offering far too much savings for customers who have shifted from oil while effectively eliminating any ability to convert customers from electricity because even a twenty percent savings will be inadequate to cause the customer to incur the added capital cost of the conversion without direct conversion cash incentives. This will only serve to lengthen the development period since it will not be possible to obtain the necessary economies of scale to create viable long-term competitive market prices absent significantly lower delivered costs of the gas commodity. The competitive market issues also arise in other classes of service as the role of alternatives such as propane and compressed natural gas (CNG) apparently become economic for some customers. The issues differ from class to class and the economics of alternative fuels are very different. For example, oil and propane require onsite storage and typically payment on delivery whereas gas and electric deliver the service as needed and payment is in arrears. In particular, the MGS class must be monitored closely relative to the cost of propane and the rates must be managed within that additional constraint.

Section Two: Rate Design Tools and Issues

In this section, the particular rate design tools available to EGNB are discussed. Essentially, EGNB uses a combination of customer, demand and delivery charges to recover its revenue requirements. For smaller customers, only customer and delivery charges are practical based on current meter technology. Further, there is a limit to the level of the customer charge in rate design before it drives away customers who use small amounts of gas on a monthly basis. In other words, raising the customer charge to promote revenue stability and closer tracking of costs would result in exceeding the competitive price ceiling for a group of low use customers. The reason is quite simple in that spreading a high monthly customer charge over very few GJs of annual use results in charges that exceed the cost of another alternative.

The competitive effect on smaller customers precludes continuing to increase the customer charge to benefit revenue recovery even though doing so would reduce the intraclass subsidies associated with volumetric rates. Thus, the only available option is to increase the delivery charges and thereby decrease the revenue stability of EGNB. The lone exception is for the residential class where the delivery charge is effectively a residual charge to recover the difference in the competitive target for the bundled delivery cost of gas and the competitive alternative less the twenty percent annual target savings. Essentially, EGNB is faced with a dilemma where the binding constraints are such that the optimum solution is excluded from the constrained set of solutions. For larger rate classes, the impact on customer bills for the lowest use customers from changes in the customer charge may well be too large and thus requires a gradual approach to rate increases. Finally, where demand charges are available, the utility cannot increase demand charges at will because doing so creates potential adverse impacts on low load factor customers in the class. It is necessary to review all of these issues for each rate design proposal that EGNB brings forward to the Board.

There are a number of other rate design and regulatory tools in use in Canada and the United States that provide a better opportunity for regulated utilities to actually earn their allowed return. These tools rely on deferral accounts or rate riders that adjust rates for changes in specific costs as identified in the riders. These tools are necessary based on a variety of costs or revenues that are wholly or partially beyond the control of the management of a utility. There is a long-established regulatory practice of according flow-through treatment to unpredictable and uncontrollable costs so that customers pay the actual costs and there are no windfall gains or losses. Examples of these flow-through cost adjustments include Revenue Smoothing Mechanism (RSM) that is effectively a full decoupling provision, Tax Expenses and other non-controllable expense items such as gas costs and pipeline charges. For example, revenue decoupling has been approved in British Columbia, Alberta, Quebec and Ontario. Further, Ontario is currently discussing the use of decoupling for electric distribution and has stated a policy preference to develop decoupling through Straight Fixed Variable rates for electric distributors.

The use of the RSM is critical for allowing EGNB to have any opportunity to earn its return. The following is an example of a lagged monthly adjustment charge:

> **Monthly Rate Adjustment**
>
> The Delivery Charge under Rate Schedules SGS, MGS and LGS is adjusted to reflect test year base rate revenues established in the latest base rate proceeding, after adjustment to recognize the greater of the number of customers from the corresponding month of the test year or the current month. The change in revenues associated with the Customer Charge is the number of customers multiplied by the Customer Charge for the rate schedule. The change in revenues associated with throughput is the test year average use per customer multiplied by the net number of customers added since the like-month during the test year and multiplying that product by the Delivery Charge for the rate schedule. The change in revenues associated with the Customer Charge and throughput is added to test year revenue to restate test year revenues for the month to include the revised values. Actual revenues collected for the month are compared to the restated test year revenues and any difference is divided by estimated sales for the second succeeding month to obtain the adjustment to the applicable Delivery Charge. Any difference between actual and estimated sales is reconciled in the determination of the adjustment for a future month. The Monthly Rate Adjustment is calculated separately for each schedule subject to decoupling.

This provision should apply to the SGS, MGS and LGS Rate Schedules.

By adopting this provision, the likelihood that EGNB recovers its costs including a return of and on its investment is improved. Given all of the risks associated with various conflicting constraints and the potential risks of volumetric pricing, this mechanism is the optimal approach to managing the risk of under recovery of base revenue requirements while also protecting the customer from over recovery. The following table illustrates the fact that the SGS, MGS and LGS rate classes all contribute significantly to the revenue instability for EGNB and thus should have an RSM type mechanism applied to the schedules.

Table 1

Fixed Cost Recovery as a Percent of Revenue

Revenue	SGS	MGS	LGS
Fixed Charge	37.2%	8.1%	7.6%
Volumetric Charge	62.8%	91.9%	92.4%

In total, the fixed charge recovery of fixed costs is about 12 percent of the total revenues for these three classes. This demonstrates the precarious situation of EGNB earnings as they relate to weather, forecast error, conservation and load shifting. RSM works in the context of the EGNB constraints because it is a balancing mechanism with true-up to revenue requirement occurring on a monthly basis with a single month lag.[1] The RSM has no impact on the aggregate savings for the customers in the SGS class since it trues up revenues to the authorized level of revenue per customer that is based on the target 20% savings versus electricity. There is no cross subsidy within the rate schedules because the RSM is a separate calculation for each schedule. That keeps the revenue per customer adjustments at the approved level for each rate class. Schedule 7.2 provides sample calculations for the RSM based on the SGS class.

In order for EGNB to remain a viable public gas utility in the face of conflicting constraints, the rate design tool kit must become more creative and more effective at providing a sound financial footing for EGNB going forward. Essentially, the Board must permit the RSM or its equivalent and the further emphasis on fixed cost recovery.

Section Three: Proposed Rate Design for 2015

The rate design process begins with the allocation of the revenue requirements among the various rate classes. Since there is a mix of market-based and cost based rates, the first step is to determine the market constraint on rates as it relates to the cost of service revenue requirements. In the case of the redefined SGS class as discussed below the market-based rate produces revenue less than the cost of service requirement. All other cost of service rates are below the applicable market-based rates. The following table compares the cost of service revenue requirements to the equivalent market-based revenues.

[1] The balancing account is equivalent to the process to match purchased gas revenues to purchased gas costs.

Table 2

Comparison of Market-Based Revenues to Cost of Service Revenues by Class of Service

	SGS	MGS	LGS	CG	ICG	OPS
Market based rates revenue	4,791,286	19,215,545	24,034,386	7,015,997	15,297,519	334,376
COS Revenue Requirement (RR)	15,338,598	16,000,377	7,682,176	3,877,072	4,395,916	73,496
Ratio of Market Based Revenue to COS RR	31%	120%	313%	181%	348%	455%

As the table illustrates, the SGS class based on the required comparison to residential electric rates results in a substantial revenue shortfall from the cost of service revenue requirements.[2] Further, the table illustrates that the potential for additional revenue recovery from the MGS class is also limited. Increasing MGS rates would rapidly force that rate above the oil alternate fuel rate. However, there is further concern that the increase in the MGS rate also makes propane an economically viable option at current natural gas commodity prices for EGNB. As a result, the MGS class has seen no additional rate increase in this proposal and a resulting decrease in rates to accommodate the customers shifting from the SGS rate class. The other classes have seen rate increases sufficient to recover the remainder of the revenue requirement.

Bill Comparison - 2014 Current Rates vs. 2015 Proposed Rates

	Profile	Current Rates	Proposed 2015 Rates	% change
SGS	85	2,137	1,725	-19.3%
MGS	505	14,062	13,074	-7.0%
LGS	3653	80,507	83,161	3.3%
CGS	8477	163,000	169,139	3.8%
ICGS	196543	3,271,575	3,298,598	0.8%

The proposal represents the most practical solution to meeting the EGNB revenue requirements given the numerous constraints imposed on the rate design.

[2] This shortfall would be less if the rates were compared to current oil prices instead of residential electric service.

The EGNB rate design proposal consists of the following factors:

1. Redefinition of the SGS and MGS rate classes;
2. An increased emphasis on fixed charges to recover fixed costs subject to the practical constraint of the bill impact on low use customers within the class;
3. The delivery charge has been held constant for ICGS and all of the increase is in the demand charge;
4. For the MGS class, the customer charge is proposed as a graduated charge to accommodate the addition of smaller commercial customers; and
5. The SGS rate has a lower delivery charge as a result of the need to set the rate at 20% below the cost of electricity.

In order to meet the residential and competitive constraints on the smallest customers currently served under the SGS Rate Schedule, EGNB proposes to redefine the SGS and MGS classes. This redefinition has the effect of reducing the dollars that would otherwise be allocated to other classes based on the revenue shortfall occurring under market based rates. Under the new definition of the SGS class, only residential customers will be served under the SGS Rate. Residential customers are those premises that provide permanent residential dwelling space for single family dwelling as defined by NB Power.
The proposed SGS rate is as follows:

Small General Service	Rate Design	Revenue
Customer Charge	$18.00	$1,784,592
Delivery Charge	$4.852	$3,006,694

The rate includes a $2.00 per month increase in the customer charge and a significant decrease in the delivery charge to produce the necessary target annual savings of twenty percent under the equivalent cost of electricity.

The removal of the commercial customers from the class results in a lower average use per customer, fewer customers and lower overall revenues from the class as compared to 2014.

The MGS rate is applicable to all commercial customers who use less than 250 GJ per month.
The proposed MGS rate is as follows:

Mid General Service	Rate Design	Revenue
Customer Charge	$20.00	$1,364,650
	$50.00	
Block 1	$12.4820	$14,168,301
Block 2	$10.8400	$1,271,076

With the addition of commercial customers using a maximum of 60 GJ in any month, it was necessary to use a graduated customer charge so that the smaller customers using a maximum of 60 GJ in any month would not experience too large an increase as the result of the fixed charge. The concept of graduated customer charges is not new and EGNB has recommended the use of graduated customer charges where costs differ based on the size of the customer. In particular, meter costs increase as the size of the customer increases. Graduated customer charges track those increases in cost. In addition, where customer charges recover less than the full customer related costs, the first rate block should be higher than the second block as in this proposal.

The definition of the LGS, CGS, ICGS and OPS rates remain the same. Each rate continues to use the same rate design elements approved in the prior rate cases. With respect to the LGS class, all components of the rate have been increased to produce the proposed revenue requirements. For the CGS and ICGS rate classes, the increases have targeted the demand charge component of the rate. For the CGS rate, the demand charge increase is tempered by an increase in the winter block rate to manage overall bill impacts. For the ICGS class, all of the increase is recovered in the demand charge. The OPS rate increase is applied to the delivery charge.

EGNB believes that this comprehensive approach to addressing rate design produces rates that are just and reasonable. When the proposed rates are coupled with the proposed RSM, EGNB is provided with an opportunity to earn its allowed return so long as EGNB is successful in managing its costs.

The following summarizes the elements in the rate design relating to the billing determination factors and monthly customer charges for each of EGNB's rate classes currently approved by the Board.

Rate Design Elements and Monthly Charges

Rate Class	Min (Monthly Demand Peak)	Max (Monthly Demand Peak)	Customer Charge ($/month)	Demand Charge ($/GJ)
Small General Service	-	-	18.00	n/a
Mid-General Service	-	<250 GJ	For customers with max. consumption up to 60 GJs/ month: 20.00 For customers with max. consumption greater than 60 GJs/month: 50.00	n/a
Large General Service	250 GJ	n/a	For customers with max. consumption up to 650 GJs/ month: 175.00 For customers with max. consumption greater than 650 GJs/month: 275.00	n/a
Contract General Service	1,000 GJ	<10,000 GJ	n/a	19.00
Industrial Contract General Service	10,000 GJ	-	3,300.00	25.66
Off-Peak Service	n/a	n/a	50.00	n/a

A copy of the rate schedules are provided in Schedule 7.1 – Rate Schedules.