DRAFT REPORT

REVIEW OF GAZ METRO'S COST OF SERVICE AND RATE DESIGN

BLACK & VEATCH PROJECT NO. 176991

PREPARED FOR

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1 Introduction

This report presents Black & Veatch's review of Gaz Metro's cost of service methodologies and rate design for gas distribution on a theoretical and practical basis.. The report is organized as follows:

Section 1 provides an introduction and discussion of applicable literature reviewed. Section 2 addresses the theory of cost of service. Section 3 discusses the practical elements of the Gaz Metro cost of service study and some underlying support for particular recommendations. Section 4 provides a theoretical review of gas LDC[1] tariff design. Section 5 provides recommendations for Gaz Metro rate changes. Section 6 provides a comparison of rate design structures of LDC's in Canada and comparable LDC's in the United States.

LITERATURE REVIEW

In addressing literature review for cost of service and rate design, it is important to distinguish between two sets of literature-theoretical analysis and practical analysis of rate design and cost of service. This distinction is important for the fundamental reason that pure theory may have limited applicability as applied to the practical aspects of utility rates. A simple example of this issue is found in the economic literature related to cost of service where theory concludes that any allocation of common or joint costs[2] between customers or classes of customers is arbitrary. While this is a sound conclusion based on theory, in practice regulators must deal with the allocation of costs as part of the process of setting rates based on the revenue requirements of the utility. The necessity of the cost of service requires that the practical side of cost analysis be addressed as well.

Theoretical literature is rich as it relates to pricing of utility service. In the context of theoretical economics there are numerous texts and professional articles that address the economics of pricing. As a result, we make no attempt to summarize this literature. Rather, Appendix A to this report provides a list of selected texts and articles that underlie our analysis of pricing and cost of service.

On the practical side, there is an evolving literature that discusses both cost of service and rate design. The authors of this report have written and published materials on these issues in both external publications and testimony before regulatory commissions. In that regard, we are particularly familiar with the results of new analyses and approaches to cost of service and rate design for gas utilities. The literature review is discussed below in the theoretical sections for cost of service and rate design.

[1] Local Distribution Company

[2] Common costs occur when the fixed costs of providing service to one or more classes or the cost of providing multiple products to the same class use the same facilities and the use by one class precludes the use by another class. Joint costs occur when two or more products are produced simultaneously by the same facilities in fixed proportions. In either case, the allocation of such costs is arbitrary in a theoretical economic sense.

2 Cost of Service Theory

There are many purposes for utility cost analysis ranging from designing appropriate price signals to determining the share of costs or revenue requirements borne by various rate classes or jurisdictions. There are also many different approaches to cost allocation. In the regulatory process, regulators use the results of cost of service studies as a useful guide for the allocation of the gas LDC revenue requirements among the various rate classes. On purely theoretical grounds, the basis for faith in cost of service studies as a tool for ratemaking is misplaced however. The reason for this conclusion, as discussed below, is that the allocation of joint and common costs is arbitrary. Nevertheless, the use of cost analysis has become a significant element of the rate process based on both legislative mandates and various court decisions. In fact, the cost of service standard for assessing just and reasonable rates is fundamental. It is also the basis for addressing other rate issues such as non-discrimination and the design of class rates.

In general, cost studies may be based on embedded costs or marginal cost. Embedded cost studies analyze the costs for a test period based on either the book value of accounting costs (a historical period) or the estimated book value of costs for a forecast test year or some combination in between. There are other possible test years based on a combination of historical and adjusted costs and revenues. Typically, embedded cost studies are used to allocate the revenue requirement between jurisdictions, classes and between customers within a class. Marginal cost studies do not reflect actual costs but rely on estimates of the expected changes in cost associated with changes in service quantity. Marginal cost studies are forward looking to the extent permitted by available data. Marginal cost studies are useful for rate design where it is important to send appropriate price signals associated with additional consumption by customers. Some regulatory jurisdictions have used marginal cost studies as the basis for revenue allocation between customer classes. This application of a marginal cost study has no sound theoretical basis and creates potential instability in costs allocated to rate classes over time. Nevertheless, the adoption of this method for allocation of average cost revenue requirement continues to be used in some jurisdictions without a sound theoretical basis.

Despite their shortcomings and the conflicts between various cost studies filed by different participants in a rate case, cost studies are a basic and necessary tool of ratemaking. They represent an attempt to analyze which customer or group of customers cause the utility to incur the costs to provide service. The concept of cost causation is central to the determination of a sound cost of service study. The requirement to develop cost studies results from the nature of utility costs. Utility costs are characterized by the existence of common and joint costs. In addition, utility costs may be fixed or variable costs[3]. Finally, utility costs exhibit significant economies of scale[4]. These characteristics have implications for both cost analysis and rate design from a theoretical and practical perspective. The development of cost studies, either marginal or embedded, requires an understanding of the planning and operating characteristics of the utility system. Further, as discussed below different cost studies provide different contributions to the development of economically efficient rates and the cost responsibility by customer class. The key element is that

[3] Fixed costs do not change with the level of output while variable costs change directly with the utility output. Most non-fuel related utility costs are fixed and do not vary with changes in throughput on the system.

[4] Scale economies result in declining average cost as output increases and marginal costs below average costs.

the cost study be carefully developed to reflect the engineering and operational analysis of cost causation. In particular it is important to recognize that throughput does not cause distribution costs and that costs are caused by a combination of customers and capacity requirements.

ECONOMIC THEORY OF PRICING

Economic theory holds that efficient prices equal short-run marginal cost[5]. For any utility characterized by economies of scale, setting prices based on marginal costs will not produce adequate revenues because marginal cost is below average cost. This same conclusion may also hold for the use of long-run marginal costs given that long run marginal costs may actually be lower than short-run marginal costs in a declining cost industry. Stated another way, utilities are declining cost industries. Given the nature of rate cases, it is often hard to understand the concept of a declining cost industry particularly when rates increase because of new capacity additions. The fact that rates increase as a result of higher costs does not change the fact that from an economic perspective the natural gas industry is a declining cost industry. To understand this issue requires an understanding of the long-run average cost curve (LRAC). The LRAC assumes that all input prices are fixed as is the available technology. In the real world, we have inflation, taxation and changing technology as well as policy changes that impact cost. As a result costs rise over time as the LRAC shifts upward with inflation, downward with changes in technology and upward with policy changes that impose added costs on utilities.

Utilities must be allowed a reasonable opportunity to earn a return of and on the assets used to serve customers. Since the utility could not satisfy the revenue adequacy constraint with prices based on marginal cost, economists developed a theoretical approach to reconciling marginal cost based prices with the revenue constraint. The theory of Ramsey pricing resolves the revenue adequacy issue by suggesting that raising prices above marginal cost in relation to the inverse of the price elasticity of the product or service provided results in the least societal welfare loss from prices that differ from marginal cost. This theory finds its practical application in the literature of two part pricing. The use of two-part pricing, or in some cases three-part, has been the foundation for utility rates since the earliest days of regulation. The use of multi-part rates is applied almost universally within the utility although with only varying degrees of support from economic theory related to efficient rates.

Under Ramsey pricing (a form of differential pricing), customers' rates are increased above marginal cost until the rates produce adequate revenues. Increases are largest for those customers or classes of service whose demand is most inelastic. To implement Ramsey pricing requires, among other things, estimates of customer or class price elasticity. Since estimating price elasticity for gas service is complex, utilities developed other practical methods for resolving the revenue adequacy issue. As noted above, the theory of multi-part pricing suggests that it is possible to recover average costs from infra-marginal prices while setting the marginal price equal to marginal cost. Thus, the use of block rates permits efficient prices while recovering total revenue requirements. Other examples of efficiency based rates includes the concept of fixed variable rate design where fixed cost recovery occurs through fixed charges (since fixed costs do not contribute to marginal cost) and variable charges recover variable costs.

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[5] See for example *The Economics of Regulation* by Alfred E. Kahn for a discussion of the efficacy of short-run marginal cost pricing.

The theory of pricing also requires a theory of class or service cost allocation. However, the existence of joint and common costs makes any allocation of costs arbitrary in the theoretical perspective. This is theoretically true for any of the various marginal or embedded cost methods that may be used to allocate costs. Theoretical economists have developed the theory of subsidy free prices to evaluate traditional regulatory cost allocations. Prices are said to be subsidy free, in the economic sense, so long as the price exceeds marginal cost but is less than standalone costs (SAC). Indeed all of this theory provides useful insight to the regulatory process where, as a practical matter, costs must be allocated between classes of service and within classes of service. For example, if the process of cost allocation results in rates that exceed standalone costs for some customers or class of customers, prices must be set below the stand alone cost but above marginal cost to assure that those customers make the maximum practical contribution to common costs. SAC plays a role in addressing issues such as discounting rates to retain customers with competitive service options elsewhere. SAC represents an element of the allocation process for cost studies and is an alternative to the concept of fully allocated costs. Unlike other more conventional allocation methods SAC relies on estimated replacement costs rather than actual costs.

On a more practical note, the concept of subsidy free rates provides a basis for regulatory agencies to allow rates that produce different returns than the system average. There is no theoretical or practical reason that class rates of return need to be equalized so long as rates fall within the zone of subsidy free rates. Regulatory policies may be used to dictate the magnitude of the return differential that is acceptable. In particular, the elements of the cost of service study may also indicate whether returns are unreasonable as a simple example illustrates. In some jurisdictions, the only rate base allocated to customers is the cost of meter and service line. Even at very low commodity delivery rates compared to other services, the cost of service study may show a very high rate of return because so little cost is allocated to the class. Nevertheless, the revenue in excess of the allowed return may be justified as a contribution to the system fixed costs that provide the service even though the costs are not explicitly allocated to the class.

EMBEDDED COST ALLOCATION

As noted above, the practical reality of regulation often requires that common costs be allocated among jurisdictions, classes of service, rate schedules and customers within rate schedules. The key to a reasonable cost allocation is an understanding of cost causation. Under the traditional embedded cost allocation, the process follows three steps: functionalization, classification and allocation. This three step process underlies the determination of cost causation. By identifying the functions for a gas utility- production, storage, transmission, distribution and customer- the foundation is laid for gas cost classification and allocation. The development of allocation factors by rate schedule or class uses principles of both economics and engineering to develop allocation factors appropriate for different elements of costs. Embedded cost allocation may provide the class costs associated with actual test year revenue requirements or simply the relationship between costs and revenues for an historic period by customer class.

MARGINAL COST ALLOCATION

Marginal cost studies, in contrast to embedded cost studies, focus on the change in costs associated with a small change in output. Marginal costs are forward looking and require making estimates of future costs with an understanding of the elements that drive those future costs. As a practical matter, marginal costs bear no relationship to the mix of actual historical costs that constitute the utility revenue requirement. The reasons that marginal costs do not reflect actual costs include the following:

1. The relationship between historic and prospective costs reflects changes in technology.
2. Sunk costs (the fixed cost of the existing system) do not impact marginal cost but may account for a large portion of the test year revenue requirement, particularly where economies of scale are significant.
3. The underlying impacts of inflation on prospective costs differ from past costs.
4. Additions to capacity are lumpy and as a result utilities optimal additions often include more capacity than the marginal change in load.

To estimate marginal cost, the first step requires determining the change in cost associated with the consumption of an additional m^3 of natural gas. Essentially, marginal costs require an understanding of the system planning process. Often, however, the planning process does not provide all of the information necessary to develop marginal cost estimates. For the typical gas LDC, additional consumption that occurs other than on the design day impacts only gas commodity costs. For added design day demand, the consumption impacts not only commodity costs but may also impact other costs for the LDC. The use of design day demand to allocate capacity related costs reflects cost causation for the LDC.

In determining the impact on other costs for growth in design day demand there are numerous factors that must be evaluated to understand the impact on costs. For example, if the design day demand is associated with adding a new customer there must be at a minimum, the investment to connect the new customer. This is the marginal customer related costs and may include some or all of the following: meter, regulator, service line, and main. For customers added within the existing system (infill customers) no new main is required to connect the customer and no new main capacity may be required in many instances because the improved efficiency of gas appliances has created available capacity to serve new loads within the existing system. To the extent that adding design day demand either for infill or for system expansion results in excessive pressure drop on the system segment, additional design day demand related capacity may need to be added. This is the marginal demand related costs for new mains. It is important to understand that making additional design day capacity available for a line segment can be accomplished in a variety of ways and may not always include adding new main. For example, capacity may be increased by increasing the pressure on a pipe segment so long as the increase in pressure does not exceed the maximum allowable operating pressure for the particular facilities. These are issues that any marginal cost study must address directly.

As the result of gas LDC conservation programs sponsored by the utility, other incentives for conservation and changes in technology such as high efficiency furnaces and water heaters, capacity is freed up on the existing delivery system and much of the new capacity requirements are customer related to connect new customers. This means that the marginal cost of gas distribution is small relative to the costs for infrastructure replacement and reliability investments. In fact, in many instances, the marginal demand related costs for a gas LDC are zero and that is certainly the

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case in the short-run on many systems and for most infill customers where only a service line and meter set (customer related costs) are required.

ADDITIONAL CONSIDERATIONS IN COST ALLCOCATION

There are other issues related to the allocation of distribution system costs related to the economies of scale in delivery service, the classification of distribution plant between customer and demand and others that will be discussed in detail in the next section of the report.

Any theoretical discussion is incomplete without addressing the issue of cost allocation as a zero sum game. Given the nature of cost allocation as a zero sum game it is always a contentious issue. If party A is successful in convincing a commission to move costs to party B, and assuming that rates are set on cost of service results, party A has lower rates. Thus even if the logic of a particular allocation is not reasonable or based in any way on cost causation (such as allocating gas main cost on commodity) it is to be expected that parties who have a smaller portion of commodity relative to demand or customer allocation will contest the analysis. It does not make the alternative allocation correct or reasonable, just pragmatic for some group of customers. If the logic of the planning and operation process of the utility system supports the allocation proposed, there is no reason for this to be a contentious issue beyond the effort of parties to secure an advantage for their constituents that is more of a fairness argument than a logical argument. From a cost of service perspective, it is appropriate to develop the cost allocation using a rigorous and factually based method so that decisions relative to other factors such as differential returns by class of customers are made based on the policy basis as opposed to an arbitrary view of cost of service.

As the above discussion notes, if the proposed cost of service study reflects cost causation based on both logic and the underlying development of the system from planning through operation, the resulting class costs represent the best possible allocation of costs based on cost causation. Dealing with the different impacts on customer classes as it relates to the allocation of revenue requirements is the providence of the regulator and its policy process as opposed to cost causation.

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3 Gaz Metro Cost of Service

Embedded gas cost of service is based on the theoretical principles discussed previously and follows the three step process of functionalization, classification and allocation. For gas cost of service, the functions are as follows: production, storage, transmission, distribution, customer and general plant. The functionalization process has been greatly simplified by the adoption of uniform systems of accounts (USOA). Gas utilities may have different combinations of plant because of the unique services provided by each utility. For example, all gas utilities providing retail service have distribution plant but may not have production, transmission or storage plant. Some utilities may own production although most do not. Some utilities may own their own storage that may be in the form of market area LNG or even market area underground storage. Market area storage differs from production area storage that requires transmission plant to deliver the gas to the market. Some utilities own no transmission plant while others may own substantial transmission assets. For those who own no transmission plant, transmission service is provided by pipeline suppliers and is purchased at regulator approved rates for firm service. In any case, the USOA provides accounts for each function. Each of the plant accounts identifies a specific cost component such as land and land rights. There is an account for this category of expense for each function production, storage, transmission, distribution, customer and general plant. The accounting system provides most of the functionalization necessary for cost allocation. Despite this detailed accounting system, issues still arise with functionalization when assets serve multiple functions. For example, storage plant may serve a capacity related function that reduces transmission costs and a commodity function that reduces annual gas commodity costs. When possible it is useful to provide additional subaccounts to recognize the function rather than just the accounting category.

ALLOCATION OF MAINS

With respect to gas cost of service issues, most gas utilities purchase gas at the well head for transportation to the utility city gate. Gas costs, to the extent that they form part of the cost of service study, require detailed analysis of how the costs are incurred and must reflect the impact of storage on the cost of gas. Gas commodity costs are the largest single item of the gas utility revenue requirement. In many cases where gas costs are recovered in a separate purchased gas adjustment (PGA or other acronyms such as GCA (gas cost adjustment)) the cost of gas may not even be included in a cost of service study for rate case purposes.

Excluding the gas cost component, the next largest cost component for a gas local distribution company (LDC) is the cost of mains. There are any numbers of allocation methods that have been recommended in LDC rate cases including peak related allocation, throughput related allocations and combination methods that use both a peak and throughput component (often referred to generically as an average and excess demand method or peak and average method). Based on the cost causation perspective there is one demonstrably superior cost allocation method for the cost of mains. The theoretically sound and practically correct method is to allocate main on both design day demand and number of customers as these are the elements that cause the costs of mains.

As we discuss below, the transmission system is designed to meet the design day requirements. Where large industrial customers are served under the interruptible rates, their cost should reflect either the dedicated cost of their own distribution line or their share of the costs of a line designed to provide adequate delivery capacity to their facility whenever that delivery capacity is used. When any capacity is built to meet the customers design day demand requirements the customer causes those costs even if the design day is not coincident with the system design day.

For Gaz Metro, the cost of service study addresses all of the costs for end use services. Each step of the allocation process follows the discussion of the best alternative for allocation of main costs. Gaz Metro currently uses a method based on Capacity Attributed and Used (CAU). This method falls in the broad general category of an average and excess demand method in that it relies on both design day demand and the volumetric use of the system.

As will be demonstrated below, volumetric use cannot be a cause of the investment in capacity from either a theoretical or empirical basis. Thus, the concept of allocating distribution mains should be revised. This basic revision does not change the treatment of the transmission lines or the use of regional allocation factors. Rather, the proposed revision reflects cost causation more accurately and more importantly addresses the issue of the correct intra class cost allocation for residential and small commercial customers. This latter advantage directly addresses the intra-class subsidy issue and supports more equitable and efficient rate designs.

Minimum System Method of Mains Allocation

This section provides the theoretical and practical foundation for a superior allocation of mains cost. This superior allocation relies on the cost causation for mains and uses both customer and demand allocation factors consistent with cost causation. It also relies on the economies of scale associated with the size of pipe installed and the standard system operating pressure that permits the smallest size of main typically installed to serve most if not all residential and small general service customers given the average system density for most gas LDCs. In addition, this result that all customers in a class are able to be served by the minimum size of main installed leads to the conclusion that the average cost of main to provide delivery service to residential and small general service customers is the same regardless of the design day peak demand or the commodity consumption of the customer. In addition, since LDCs use the same meter, regulator and service for residential and the smallest general service customers, the delivery cost for these customers is also the same. When allocating the minimum system component to the smallest customers also serves the class design day demand, there is no need to allocate any additional distribution capacity costs to the smallest customer class based on demand. Thus the demand cost equal to the main cost not included in the customer component is allocated to the remaining classes based on design day demand.

The correct measure of the demand allocation factor may or may not include all of the remaining classes of customers that cannot be served by the minimum system. For customers served off transmission mains there would be no allocation of distribution demand. If customers pay for their own facilities through a contribution in aid of construction there would be no further allocation of demand. In general, however, it is appropriate to allocated the demand related portion of mains cost on the design day capacity added to serve the customers. In some cases the design day for a

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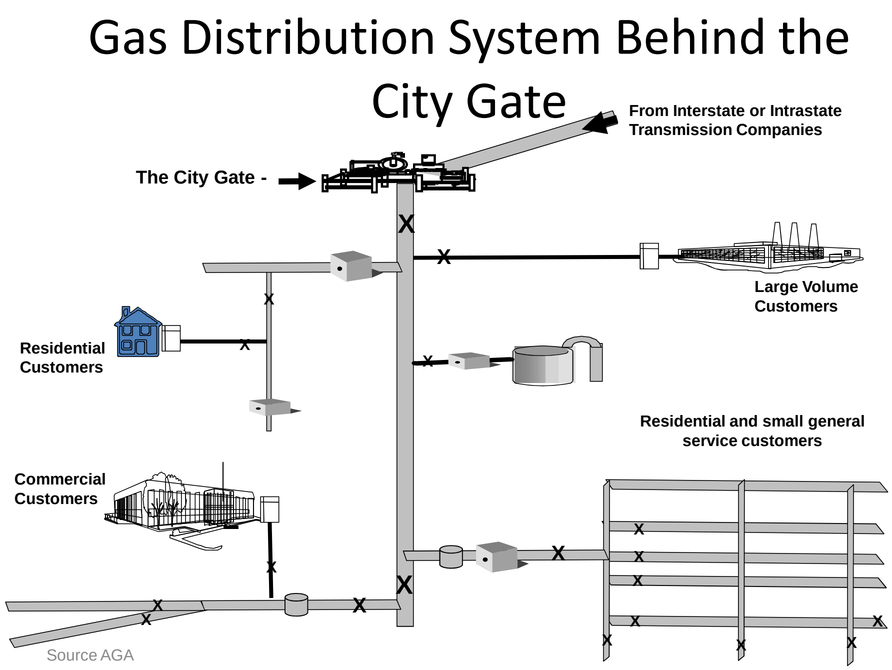
class may not be coincident with other classes of service. Interruptible loads that may be interrupted as the result of transmission constraints on the system design day will have their design peaks at other times and thus the use of the non-coincident peak design days is appropriate for allocating distribution service mains.

The beginning point of any discussion related to the above conclusion must be with the rationale for allocating the cost of mains on both a customer and a demand basis. The cost of distribution mains are determined by two major factors: (1) the number and location of customers and (2) their demands (albeit for gas distribution the impact of demand becomes less important when pipe scale economies for residential and small commercial customers cause the minimum installation to also serve design day demand.) Utility cost studies have traditionally attempted to identify a portion of distribution costs as customer-related and the remaining portion as demand-related. The customer related considerations play a much larger role since local facilities and policies reflect the underlying customer mix and density.

This customer impact is illustrated in Figure 1. Figure 1 is a simplified diagram of a gas LDC system.

Figure 1 Typical LDC System



The diagram shows in a simplified form the components of a gas LDC system. The city gate is the point of interconnection of the LDC with its gas supply pipeline. The diagram shows how larger C&I[6] customers may be connected by their own main as a direct feed. Typically, these customers are large industrial customers such as a power plant, refinery or a fertilizer manufacturer. The diagram also shows how larger commercial customers are connected off larger mains that move gas for these customers and for smaller customers further downstream from the city gate. In some

[6] Commercial & industrial

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instances, a single residential customers may be served off larger pipes with higher pressures because it is more convenient to do so for the utility as shown in the middle left of the diagram. This arrangement is often referred to as a farm tap. In that case, the utility incurs added costs for regulation because of the greater pressure drop to serve a customer off these larger and typically higher pressure mains. More commonly, residential and small customers are served from a network of pipes that must run throughout the neighborhood. This is illustrated by the residential neighborhood in the lower right hand corner of the schematic. Such a development might also include small general service customers as well.

Several important points may be noted from this diagram. First, the diagram illustrates that a gas LDC must provide footage of main to cover a larger area based on the density of its customer mix. Just by looking at the diagram it is easy to see that there is more footage because of smaller customers. This conclusion is also consistent with residential line extension policies that provide for a length of main to connect residential customers. Historically, an extension policy would have allowed, for example, 100 feet of main for each new residential customer. Under current policies that are based on revenues, the system expands with each new residential customer by adding footage to connect the customer. Second, the diagram illustrates that larger mains also serve smaller mains. This is important because the capacity in a two inch main is not used to serve larger mains.

Third, LDCs must plan to meet the design day requirements of the system. Important in that consideration is the concept of economies of scale. The concept of scale economies is best illustrated by an example. Gas system scale economies reflect the relationship between the installed cost of pipe by size and type coupled with the increased capacity from pressure and pipe diameter. Simply doubling the size of the gas main more than doubles the available capacity of the main at a cost only slightly greater than the cost of smaller pipe and typically much less than double the smaller size all else equal. For a low pressure system, increasing pipe size from two inch to four inch allows over five times the amount of gas to flow and under higher pressure, the flow rate increases by more than six times that of two inch pipe all else equal. The resulting cost causation implies that larger customers impose lower per unit costs for design day capacity on the distribution system than do smaller customers. Table 1 below provides the data for Gaz Metro based on the installed cost per meter of main and the available capacity to serve load based on standard operating pressure for the system.

Table 1 Main Cost Comparisons

LINE DIAMETER	COST OF MATERIAL PER METER	INSTALLATION COSTS	TOTAL COST PER METER	FOR 1 KM / 400 KPA / DESIGN DAY CAPACITY M³/DAY	COST PER M³/DAY
2 " (60,3 MM)	$4.50	$125.74	$130.24	14,352	$0.00907
4 " (114,3MM)	$12.67	$136.99	$149.66	68,352	$0.00219
6" (168,3 MM)	$32.19	$187.11	$219.30	178,704	$0.00123

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If for example, we use a customer density for the Gaz Metro system of 20 customers per kilometer of line (slightly above the average density of Gaz Metro), the minimum size of pipe installed will serve the design day load characteristics of the smallest residential or commercial customers and even for larger customers up to 65,481 m^3 per year assuming a 25 percent annual load factor.[7] This means that residential customers using under 65,481 m^3 annually have the same cost as all other residential customers based on the assumptions of density and operating pressure. Less than one percent of residential customers served by Gaz Metro use more than 10,950 m^3 and none use more than 36,500 m^3. For a more urban density such as in the city of Montreal where there are more customers than the system wide average for Gaz Metro, the 36,500 m^3 would represent an appropriate level of maximum annual use that permits two inch main to serve all of the customers[8]. Similarly, small commercial customers using under 65,481 m^3 annually have the same cost as other commercial customers. For larger customers that may be served off 4 inch main, the design day capacity cost is lower in total than for smaller customers up to 271,091 m^3 or 4.14 times the design day capacity requirement of the largest customer served off the 2-inch main. This means that the total cost of serving the next largest size of customers is actually less per customer (assuming that these customers could be uniquely identified for rate purposes) than for the smallest customers on the system. Every gas LDC will have different densities, maximum pressures, allowable pressure drops, installed cost of pipe and distribution of customers. In general, the basic result that the minimum system will serve most or all residential and small general service customers will hold for most gas systems as it does here.

The maximum size of customer served by the minimum system used in this calculation represents the most restrictive assumptions about the system in that it assumes a one kilometer lateral fed from one end. If the feed was located at another point or the pipe had an additional feed at the other end the maximum demand that the minimum system served would increase. That demand also increases with higher operating pressure or lower density. As density increases and operating pressure declines, less design day load is served. However, if load grows the typical minimum sized pipe will operate at higher pressures and will increase the demand that may be served[9]. The significance of economies of scale for residential and small general service customers who can be served from the minimum system is that there is no reason to allocate these customer classes any additional design day demand related costs. This means that the design day capacity from the minimum system is adequate to serve these customers and no additional costs needs to be allocated to the customers that are adequately served with the minimum system. For the remainder of the classes, the demand allocation should be based on the classes' contribution to the design day demand excluding the demand of those classes served by the minimum system. This step is accomplished by deducting the customer component classification of mains from total main costs before allocating the remaining costs classified on demand.

[7] This is an estimated annual load factor for a residential customer of the LDC.
[8] Note that this analysis is based on the most restrictive assumption that all of the customers on the main segment are the equal in size to this largest customer and that the main segment is a lateral line as discussed below.
[9] The ability to increase pressure on a portion of the system depends on several factors such as the MAOP (Maximum Allowable Operating Pressure) for the type of main, pressure availability and so forth.

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Common Critiques of the Minimum System Method

Some analysts and regulators will doubtlessly reject this concept because the results do not comport with the political outcomes their constituents find appropriate. In this group are those who represent the residential customers before commissions and those commissions who want to continue the subsidy to residential customers without calling it a subsidy. The arguments raised against the outcomes of this method vary from jurisdiction to jurisdiction. Among those who oppose the method, some argue that smaller customers get no benefit from the economies of scale under this method. That argument is incorrect because the minimum system factor is applied to the total investment in mains and the smaller classes are allocated a percentage of the total costs. The total system costs recognize the economies of scale inherent in the system. The allocated share of costs from the minimum system is lower as a result of scale economies.

Some analysts have argued that smaller customers in urban areas are over allocated costs based on the minimum system. This argument is also incorrect because the minimum system analysis is based on average system costs that include both urban and suburban costs. If anything, this benefits urban customers where the cost of installation and maintenance is higher than for suburban areas based on the cost of installing main under the streets along with all of the other utility services in the same corridor. The density of customers is actually offset by the higher cost of installing and maintaining gas lines in the urban areas.

Finally, there is an argument that the two inch system has excess capacity and those costs are borne by customers who do not use the capacity. This argument fails for a number of reasons. First, gas system additions are lumpy. That is it is not economic to only install the exact amount of capacity needed to serve the load. Rather, the installed capacity is designed to serve the changing load over the life of the plant. Second, the customers who benefit from this planning process are both current and future customers in the residential and small general service classes who have adequate capacity to meet the service requirements of the customers. Unused capacity in the minimum system will serve customers who are added to the system through main extensions or system infill. Third, most of the cost of main is associated with installation. In the case of Gaz Metro the installation represents over 96% of the installed cost of two inch main. Given that there is very little saving associated with the cost of pipe, there is no reason to install smaller pipe that would need to be replaced as customers were added to the system thus increasing overall costs for the system.

QUANTITATIVE SUPPORT FOR THE MINIMUM SYSTEM METHOD

As discussed previously, the resulting rates of return using the minimum system method will still be subsidy free so long as they recover marginal cost and are less than standalone costs. This allocation has implications for the appropriate rate design for smaller customers to avoid intra-class subsidies and undue discrimination. This means that certain parties would rather use unsupported allocations to produce a result that they favor. Although the allocation of mains using the minimum system concept is sound based on the theory discussed above, it is not only theory that demonstrates the superior nature of this allocation. This conclusion may be tested for a variety of data to also demonstrate that this allocation is superior to all other methods.

To determine cost causation requires a series of steps that begin with the recognition that causation requires a formal model specifying the theoretical basis for a relationship. From the model, we develop a set of assumptions and deductions are drawn from them. The model is useful in explaining causation if the assumptions capture the essential features of the process and the model itself is successful in interpreting and predicting the outcomes of the process. Essentially, the observation that the investment in mains is a function of both customers and design day demand is a theoretical model derived from observing the design and planning for a gas LDC and from observing the way that main costs are incurred to support growth and to meet the design day. Thus we observe that new investment is required to extend the system to connect new customers that are currently beyond the existing system and that investment is made in looping or expanding pipe capacity to solve pressure problems in areas where significant growth has increased the need for additional design day capacity.

A necessary condition for cost causation is that the dependent variable (mains cost) be correlated with the independent variable (number of customers). This however is not a sufficient condition since correlation does not, by itself, equate to causation. There are potentially two different applications of the fundamental model looking solely at the relationship between customers and mains. The model specification will vary based on the type of data used to test the model. Since the model is based on an extensive data base for US gas LDCs, the data is in miles as opposed to kilometers. For cross section data, the general model will take the form of a linear model as follows:

Model One Specification

Miles of Main= Intercept + m*customers + error term.

In this model the intercept term may be significant because we are looking at established systems that also include a demand component based on design day. In this analysis, however, we do not have the design day requirement for each of the systems analyzed. For our purposes, it is sufficient to show that customers explain the miles of main as a proxy for cost of main because we cannot reject the hypothesis that the coefficient m is different from zero.

To test our equation, several data bases are available. First, approximately 1400 gas LDCs provide basic statistical information regarding their systems to the Pipeline and Hazardous Materials Safety Administration of the US Department of Transportation (DOT). These DOT reports contain information about both miles of main and the number of services of the LDC. There is no customer data but since the relationship between services and customers is nearly one-to-one, it is possible to use services as a proxy for customers. Based on a data base of reports from 2005-2009, using the simple model above, the number of services (customers) explains over 93% of the variation in the dependent variable miles of main. Every regression statistic is significant and thus we can reject the hypothesis that the variable services coefficient is zero. We can also reject the hypothesis that the regression equation is insignificant. Thus, using services as a proxy for customers the model explains most of the variation in miles of main. To the extent that all variation is not explained, the variable design day capacity would need to be included also in the equation. That variable is not available and in this model would not be helpful since it is not miles of main but cost of main that is impacted by design day demand.

A second equation for testing the relationship without an intercept term is given by the following equation:

Model Two Specification

Miles of Main= m*customers + error term.

We find that customers still explain 93% of the variation in miles of main with both a higher F statistic and a t statistic. Thus the theoretical model that does not include the intercept term is superior to the inclusion of the intercept. From a theoretical standpoint this model is superior to the model with an intercept term because if the variable customer equals zero we would expect the variable miles of main to be zero.

A second data set based on EIA and DOT data as compiled by AGA includes both miles of main and the number of customers for a group of over 100 companies. That data base also includes data on throughput for each company so that we can test an alternative model that suggests that throughput is an appropriate cost causation variable. That is, some analysts argue that the model for miles of main should be specified as follows:

Model Three Specification

Miles of Main= Intercept + m*customers + n* MCF[10] + error term.

The EIA/DOT data base allows for testing both the original model as well as the alternative model with a zero intercept term. The composite data base consists of data for the years 2005-2009 (the latest year available). Using this data to test our original model, we find that customers explain 83% of the variation in miles of main when using Model One. As before, all of the statistics of the model are significant. If we test Model Two using the same data we find that customers explain 87% of the variation in the miles of main. The results of this equation are significant for each variable and, in addition to the higher R-square, the F- and t-statistics are also larger than in the equation with the intercept. Thus we can conclude that customers cause the investment in miles of mains.

With respect to the claim that throughput (MCF) causes main cost Model Three explains 83% of the variation in miles of main. However the coefficient of the MCF variable is barely significant and contributes virtually nothing to the explanatory power of the regression. If we test the model without the intercept term, we find that the model explains 87% of the variation in miles of main and the MCF coefficient is barely significant and contributes virtually nothing to the explanation of miles of main. Thus, we can conclude that throughput does not cause the investment in miles of main.

We are left with the explanation that the primary cause of mains cost is the number of customers and the remainder of the cost is design day demand that becomes the second most important variable in explaining the investment in main. Each data set confirms the conclusion that both customers and demand but not throughput causes the investment in mains based on an empirical analysis.

Finally, we developed a data base containing the dollars invested in mains, number of customers and total gas deliveries in DTH[11]. The data base represents over 50 companies with data taken from gas LDC annual reports filed with state regulators. This is the only data base with the actual

[10] One thousand cubic feet of natural gas or about 1.055 GJs based on 1000 BTUs per cubic foot.

[11] Dekatherm or 1.055GJs

investment in mains rather than miles of main. The data base has between nine and twenty-one years of data for each company. The data base does not have design day demand since that data is not reported. However, we were able to test two models for explaining investment in mains.

Model Four Specification

Dollars of main investment= m*customers + n* DTH+ error term.

In this analysis, the intercept term is set to zero since we are testing time series data for a sample of utilities. The sample consists of 53 gas utilities from all over the United States. Each utility has at least nine years of data and most have more than ten years. A regression analysis was prepared for each utility based on the Model Four specification above. In addition, the analysis was repeated for an additional model specification.

Model Five Specification

Dollars of main investment= m* customers + error term.

Model Five is compared to Model Four relative to the portion of the change in investment in mains explained by the independent variables in each equation. The comparison shows that in most cases the variable DTH adds little to the R-square and hence the explanation of mains cost is as we have hypothesized. Main costs do not vary with throughput. Interestingly, in those models where the variable is statistically significant, the sign of the variable is uniformly negative with one exception. This seemingly puzzling result is explained by the fact that adding larger higher load factor customers is less costly per unit of throughput and therefore increases load at a greater rate than the increase in costs. For those utilities where the throughput variable was insignificant, the R-square for the two models is about the same with the only effect on R-square being an additional independent variable.

Table 2 below summarizes the results of testing both Model Four and Model Five.

Table 2 Comparison of Model Four and Five Results

MODEL	AVERAGE R-SQUARE	RANGE OF R-SQUARE
Model Four	98.6	91.0-99.9
Model Five	97.7	90.7-99.9

Model Four has the extra variable and thus adds marginally to the R-square. However, the additional portion of the explanation of the variation in mains cost contributed by the variable DTH is minimal. Further, the sign of the variable DTH is negative in all but six of the companies and in five of those the coefficient is not statistically different than zero. In all of the other cases, the sign for the throughput variable is negative.

Summary of Quantitative Support of the Minimum System Method

Based on the analysis of data from multiple sources, it is reasonable to conclude that customers cause investment in mains and throughput does not. Thus, the politics of allocation whereby mains are allocated on commodity is just that- a political solution but not a factual one. As a practical matter, it is incumbent on the regulatory process to produce theoretically sound analysis of cost causation. That is done using both customer and demand to allocate main costs. It is also important to recognize that the customer component is calculated using the minimum system method because of the importance of economies of scale in allocating costs for the mains component.

REVIEW OF GAZ METRO COST OF SERVICE ALLOCATIONS

The following section presents Black & Veatch's review of Gaz Metro's current cost allocation methodologies. The focus of this review is on how rate base and revenue requirements are classified to the components of Customer, Capacity, Volume, Income, and Direct. It is understood that Gaz Metro has a current agreement with the Regie de l'energie on all cost allocation assumptions. Black & Veatch is providing some alternative methods that in our view should be adopted in future rate proceedings as a replacement for the current agreement to improve cost allocation both theoretically and practically.

Rate Base Cost Allocation

The following table presents the classification of rate base for the most recent rate case. As the above table illustrates, the Gaz Metro Cost of Service study uses a limited number of rate base allocation factors. Based on the particular allocation factors the fundamental question is whether the chosen allocation factors reflect cost causation. Black & Veatch has analyzed each function and the allocation factor used to spread the costs among rate and sub-rate classes. Based on that review we conclude as follows:

1. The transmission and contribution accounts allocations and the cost of structures and improvements (city gate facilities owned by the utility) do not reflect cost causation because the same allocation factor that is used for mains is also used for transmission and related structures and improvements for both transmission and distribution. The transmission system is designed, built and operated to provide for reliable service for the system on the design day. While one might argue that customers could not be served without the transmission system to move gas from points of interconnection with inter-provincial gas transmission companies to more remote market areas, there is theoretically no customer component of the transmission system[12]. The use of the main allocator for facilities designed and built to meet the design day requirements of a gas system results in an over allocation of these costs to smaller customers because of the inclusion of a customer component. The transmission investment and city gate costs are appropriately allocated on a design day demand basis after making any direct assignments of facilities dedicated to an individual customer served off transmission laterals. Black & Veatch understands the reason that transmission assets use the same allocation as distribution mains is that the CONDPRIN allocator is used for the entire distribution network. We encourage Gaz Metro to develop transmission specific costing using the largest size of mains. This would provide the ability to allocate transmission assets on a demand basis (Capacity Attributed (CA)) and eliminate the customer component. This treatment would apply to Other Access Roads as well.

[12] In fact, there are three customers in the Gaz Métro franchise that are linked directly to transmission lines for cost efficiency choice. This is essentially the concept of a farm tap noted above in the system diagram.

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Table 3 Rate Base

	Total $	Allocation Factor	Classification				
			Direct	Customer	Volume	Income	Capacity
Distribution Rate Base	$		$	$	$	$	$
Unamortized Costs	172,889,000	various					
Fixed Assets							
Distribution network							
Transmission	17,272,000	CONDPRIN	0	5,150,510	0	0	12,121,490
Contribution Transmission	(8,636,000)	CONDPRIN	0	(2,575,255)	0	0	(6,060,745)
Structures and Improvements	22,949,000	CONDPRIN	0	6,843,392	0	0	16,105,608
Mains	832,059,000	CONDPRIN	0	248,119,994	0	0	583,939,006
Other and access roads	53,166,000	CONDPRIN	0	15,854,101	0	0	37,311,899
Services	392,108,000	FS21	392,108,000	0	0	0	0
Meters and regulators	93,818,000	FS22	93,818,000	0	0	0	0
General installations							
Ground, structure and improvement	52,935,000	IMMOBILD	19,631,359	9,931,146	0	0	23,372,495
Various equipment and material	26,133,000	IMMOBILD	9,691,628	4,902,817	0	0	11,538,555
Rolling stock and machinery	29,331,000	IMMOBILD	10,877,631	5,502,795	0	0	12,950,574
Deviation of the general installations	(532,000)	IMMOBILD	(197,296)	(99,809)	0	0	(234,895)
Biogas	7,319,000	Biogas	7,319,000	0	0	0	0
Contributions							
Contributions - infrastructures	(24,623,000)	CONDPRIN	0	(7,342,579)	0	0	(17,280,421)
Governmental subsidies	(27,262,000)	CONDPRIN	0	(8,129,528)	0	0	(19,132,472)
Contributions - construction	(7,272,000)	CONDPRIN	0	(2,168,510)	0	0	(5,103,490)
Contributions - P.E.R.D.	(32,847,000)	CONDPRIN	0	(9,794,975)	0	0	(23,052,025)
Works in progress	11,960,000	CONDPRIN	0	3,566,472	0	0	8,393,528
	1,437,878,000	0	533,248,322	269,760,570	0	0	634,869,108
Working Capital	20,784,000	various					
Self Insurance	(1,393,000)	BASETARD	(557,623)	(245,022)	(8,508)	(24,904)	(556,944)
Total Rate Base	1,630,158,000						

2. With respect to mains, the allocation factor correctly includes both a customer and demand component in the allocation. However, Black & Veatch does not agree with the determination of the demand component. Gaz Metro uses the Capacity Attributed and Used (CAU) method for determining capacity allocation. The CAU method includes a volumetric component that as previously discussed is not appropriate for allocation of distribution mains. The correct method would be to only use Capacity Attributed (CA) based on maximum daily demand (MDD). Black & Veatch is also concerned that the method for reflecting customer and demand is not reasonable. The method likely understates the customer component of cost and overstates the demand component. The result is that the costs for residential and small general service customers is likely understated and the costs for customers within the class are excessive for the larger customers who are subsidizing the smaller customers in the class. In fact, Black & Veatch believes that the resulting rates for the smaller subrates with the D_1 rate schedule create undue discrimination within the class based on the excessively high rates for larger customers within the group despite the fact that the cost to serve these customers is on average the same as for smaller customers. Essentially, the delivery service cost is the same for all of the smaller customers under the D1 rate schedule as we discussed in the theoretical section of the report. By using this approach to cost allocation, the resulting revenue

requirements and the intra-class cost allocation through rates is both reasonable and theoretically sound.

3. With respect to general plant, the use of an allocation factor based on distribution plant is not representative of the industry best practice. Land and structures are designed to house employees. These costs are typically allocated in the same way as payroll is allocated. Payroll components are allocated to customer and demand based on the underlying allocation of the functions performed. For example customer service personnel are classified as customer and allocated on customers. Payroll associated with operation and maintenance expense of mains is allocated on design day demand related. Payroll associated with operation and maintenance of mains is classified as both customer and demand. Thus all payroll accounts have some underlying demand and customer component. Office space and related equipment such as furniture and computers are classified and allocated based on the underlying payroll allocations. Currently, Gaz Metro uses the IMMOBILD allocation factor for all general plant accounts. Based on the discussion above, Ground, Structure and Improvements should be allocated on a payroll basis. The other general plant accounts, such as rolling stock and machinery, tools and equipment should continue to be allocated based on the underlying allocation of plant.

4. Credits to rate base should be allocated in the same way as the related plant for contributions. Government subsidies should be allocated in the same manner in which the subsidies are produced. For example if some are for specific classes of customers, those should be directly assigned to that class. If subsidies relate to plant such as tax abatements they should be allocated in the same manner as the plant. Gaz Metro correctly uses the same allocation as distribution plant (CONDPRIN) to allocate these credits.

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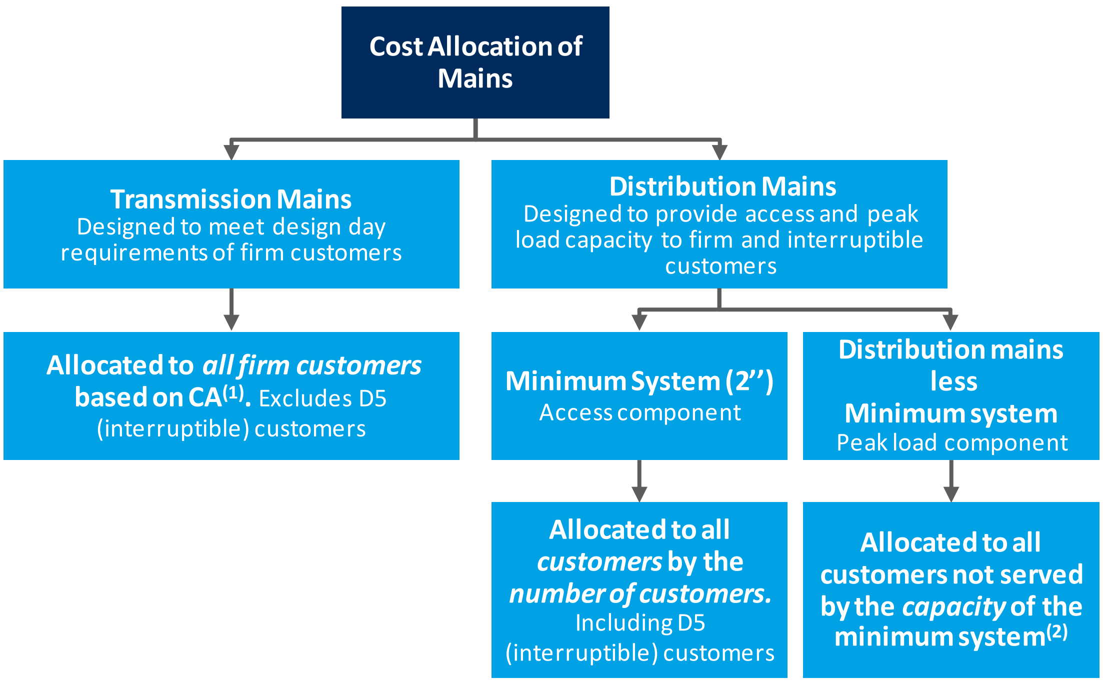
Black & Veatch's Proposal for Mains Allocation

As discussed in the previous sections, Black & Veatch disagrees with the current use of the CONDPRIN allocation for the allocation of Mains, primarily due to the inclusion of a volumetric component to the allocation. This section describes the proposed revisions recommended for Gaz Metro.

Figure 2 Cost Allocation of Mains



Notes:

(1) CA (Capacity Attributed) is the measure of the design day capacity required to meet the firm load obligation on the coldest day expected for the system. Also referred to as Maximum Design Day (MDD)

(2) Uses CA for firm customers and maximum D1 over 36,500 m3, D3, D4, and peak load for D5 (interruptible)

As shown in Figure 2, we first recommend that Mains cost be separated into Transmission Mains and Distribution Mains. The reasoning for this is that transmission and distribution mains are designed for and serve two different purposes in an LDC's system. Transmission mains are designed and sized to meet the maximum design day (MDD) requirements of all firm customers on the system. Note that the MDD for interruptible customers is not considered when designing the transmission network. Distribution mains are designed to provide access to the system, as well peak load capacity for all customers, firm and interruptible.

The costs of Transmission Mains should be allocated on a demand basis using the CA allocation for all firm customers. Interruptible customers are not allocated cost of the transmission system because their MDD is not considered in the design of the transmission network.

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Distribution Mains, as demonstrated previously, should be allocated using both a customer and demand component using the minimum system method. Under the minimum system method, the embedded cost of mains is split between the customer component and the demand component by taking the percentage of total main costs represented by the minimum system as the customer component. These costs would be allocated based on the number of customers in the system. The demand component is then all distribution mains costs that are not part of the minimum system. These costs represent the costs to serve the peak loads on the distribution network. These costs are allocated to all customers on the system not served by the minimum system. For firm customers, the costs are allocated using the CA method. For interruptible customers, the costs are allocated based on peak load. This method captures the costs for serving the non-coincident peaks (NCP) on the system.

Distribution Revenue Requirements

As the following table illustrates, the Gaz Metro Cost of Service study uses multiple expense allocation factors. Based on the particular allocation factors the fundamental question is whether the chosen allocation factors reflect cost causation. Black & Veatch has analyzed each function and the allocation factor used to spread the costs among rate and sub-rate classes. Based on that review we conclude as follows:

1. As a general rule, operation and maintenance accounts should be allocated based on the same allocation factor used for the plant accounts. Thus the allocation of main O&M should be allocated in the same manner as mains. Gaz Metro follows this methodology so the only question relates to the discussion of the allocation factors above related to mains.

2. The direct assignment of costs associated with O&M for services, meters and regulators is appropriate with the underlying costs allocated in the same manner as the rate base costs.

3. Administrative expenses fall in to several categories each of which should have its own allocation factor. For example expenses associated with human resources such as staff costs, benefits costs and other employee related expenses should be allocated as payroll. Insurance expenses should be allocated on net plant. However, we understand Gaz metro bundles insurance costs with other administration costs and does not separately identify insurance. Where expenses cover a variety of areas the use of a payroll allocator in conjunction with appropriate direct assignments represents the best allocation method.

4. Other allocation factors appear to be appropriate although it is not clear why lost and unaccounted for gas, compressor electric costs and mercaptan costs should be included in distribution rates in an unbundled system. These costs are related to total throughput on the system because both system gas and transport gas incur these costs. Black & Veatch believes that these costs should be recovered directly from transportation customers on a volumetric basis and the remainder included in the gas cost recovery mechanism for customers who use system gas. As a simple illustration of the way these costs are recovered from transport and other customers the rates for transport would include a lost and unaccounted for gas adjustment through loss factor applicable to transportation gas. The loss factor would be determined on a system basis and be used to reduce the volume of gas delivered for a transport customer at the city gate to a delivered volume at the meter. For example if the loss factor is two percent and the customer delivers 100 GJs at the city gate, Gaz Metro would only deliver 98 GJs to the customer meter. Compressor and mercaptan costs would be calculated

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through a formula on an annual basis. The cost would be the sum of the operating costs for all of the facilities associated with the compressor system plus the cost of mercaptan divided by the total system throughput as delivered to the customers' meters. The resulting unit costs would be applied uniformly to the transport volumes and the sales volumes for the system. This adjustment would include a true-up provision to match actual costs and revenues.

Table 4 Operation and Maintenance Expenses

		Allocation	Classification				
	Total $	Factor	Direct	Customer	Volume	Income	Capacity
Distribution Revenue Requirements/Test Year Cost of Service							
OPERATING COSTS							
Principal conduits	15,484,000	CONDPRIN	-	4,617,329	-	-	10,866,671
Connections and deviations	5,969,000	FS21	5,969,000	-	-	-	-
Meters and regulators	3,612,076	FS22	3,612,076	-	-	-	-
Customer service	10,724,030	FB08	-	10,724,030	-	-	-
Expenses of sale and representation	10,530,523	FS27	-	4,738,735	4,738,735	1,053,052	-
Expenses of publicity	3,979,567	FS28	-	1,034,687	1,034,687	1,910,192	-
Expenditure of administration	93,073,856	EXPLOITD	13,608,878	50,006,685	8,200,520	5,822,845	15,434,927
Accounts Department of the subscribers							
Contracts, calls customers and orders	5,178,833	FS23	-	5,178,833	-	-	-
Statements of meters	0	FS24	-	-	-	-	-
Invoicing of the subscribers	4,423,264	FS25	-	4,423,264	-	-	-
Credit and covering	2,923,992	FS29	-	2,923,992	-	-	-
Provisions - bad claims	1,010,000	FS26	-	-	-	1,010,000	-
Other expenses - compt. abon.	1,691,620	HALF-VALUE L	-	1,565,399	-	126,221	-
TOTAL OPERATING COSTS	158,600,761		23,189,954	85,212,955	13,973,943	9,922,311	26,301,598
DISTRIBUTION EXPENSES							
Waste gas in the network	6,054,000	FB01D	-	-	6,054,000	-	-
Transmission electricity	1,524,000	FB01D	-	-	1,524,000	-	-
Mercaptan and others	300,000	FB01D	-	-	300,000	-	-
deferred amortization	5,967,000	FB07D	-	-	-	5,967,000	-
Compression Biogas	1,060,000	Biogas	1,060,000	-	-	-	-
SUBTOTAL DISTRIBUTION EXPENSES	14,905,000	0	1,060,000	0	7,878,000	5,967,000	0
GLOBAL LEVEL OF ENERGY EFFICIENCY	12,493,000	PGEE	-	-	6,246,500	6,246,500	-
FUNDS OF ENERGY EFFICIENCY		FAIRY	-	-	-	-	-
FUNDS GREEN	40,248,000	FB01FV	-	-	40,248,000	-	-

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Table 5 Other Revenue Requirements

AMORTIZATION EXPENSES							
Distribution network							
Contributions	-7,123,000	CONDPRIN	0	-2,124,079	0	0	-4,998,921
Principal conduits	39,931,000	CONDPRIN	0	11,907,424	0	0	28,023,576
Grounds and constraints	390,000	CONDPRIN	0	116,298	0	0	273,702
Civil part of the stations	560,000	CONDPRIN	0	166,992	0	0	393,008
Stations of delivery and relaxation	3,744,000	CONDPRIN	0	1,116,461	0	0	2,627,539
Equipment and tools of compression	0	CONDPRIN	0	0	0	0	0
Connections and deviations	27,346,000	FS21-A	27,346,000	0	0	0	0
Meters and regulators	6,632,000	FS22-A	6,632,000	0	0	0	0
General installations	13,911,000	IMMOBILD	5,159,003	2,609,845	0	0	6,142,151
Biogas	309,000	Biogas	309,000	0	0	0	0
TOTAL AMORTIZATION EXPENSES	85,700,000		39,446,003	13,792,942	0	0	32,461,055
AMORTIZATION EXPENSES OF DEFERRED CHARG	41,920,239	various	23,790,675	4,295,289	378,071	7,247,145	6,209,059
TAXES AND ROYALTY							
Taxes various							
Tax on the network	11,709,000	REVBRUTD	0	0	0	11,709,000	0
Tax on the capital	506,000	BASETARD	202,554	89,003	3,090	9,046	202,307
Real estate taxes							
Transmission network	3,376,000	CAUCPA	0	1,006,723	0	0	2,369,277
Places of business	1,694,000	IMMOBILD	628,233	317,812	0	0	747,955
Royalty with the control							
Royalty with the control building/energy	3,892,000	FB01D	0	0	3,892,000	0	0
Quota at the agency of energy efficiency	2,767,000	AEE	2,767,000	0	0	0	0
TOTAL TAXES AND ROYALTY	23,944,000		3,597,787	1,413,538	3,895,090	11,718,046	3,319,539
INCOME TAX CONNECTED TO THE OUTPUT	25,756,000	REVNETD	0	0	0	25,756,000	0
INCOME TAX NOT CONNECTED TO THE OUTPUT	1,893,000	IMMOBILD	702,034	355,146	0	0	835,820
DISCOUNTS AND OTHER CONSUMER	1,046,000	various	1,046,000	0	0	0	0
SUB-TOTAL DISTRIBUTION COSTS	406,506,000		92,832,453	105,069,869	72,619,605	66,857,002	69,127,071
PERFORMANCE BASED PRICING	124,381,000	BASETARD	49,790,144	21,878,005	759,646	2,223,673	49,729,532
TOTAL COST OF DISTRIBUTION	530,887,000		142,622,597	126,947,874	73,379,251	69,080,675	118,856,602

As the above table illustrates, the Gaz Metro Cost of Service study uses multiple expense allocation factors. Based on the particular allocation factors the fundamental question is whether the chosen allocation factors reflect cost causation. Black & Veatch has analyzed each function and the allocation factor used to spread the costs among rate and sub-rate classes. Based on that review we conclude as follows:

1. Amortization expenses are appropriately allocated in the same manner as the underlying plant.

2. Taxes are appropriately allocated as plant for those based on property values. Taxes collected on sales or revenues should be allocated on sales or revenue. Taxes on capital should be allocated on capital employed (rate base).

3. Income taxes are appropriately allocated on net income. Income Tax Not Connected to the Output (deferred taxes) are appropriately allocated on distribution rate base (IMMOBILD).

4. Return requirements should be allocated on rate base.

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4 Theoretical Issues in Rate Design

A gas tariff consists of three elements: Terms of Service, Rate Schedules and Rules and Regulations. Each of the three elements complements and relies on the other elements in an integrated fashion. This framework permits ease of understanding and presentation while also allowing a complete presentation of all tariff documentation. In this section, the Report focuses on the issues associated with rate design.

In designing rates, it is appropriate to recognize a number of rate design principles or objectives that find broad acceptance in regulatory and policy literature. Regulators frequently cite these or similar principles when adopting rates. These include:

1. Efficiency;
2. Cost of Service;
3. Value of Service;
4. Stability;
5. Non-Discrimination;
6. Administrative Simplicity;
7. Balanced Budget.

These rate design principles draw heavily on the "Attributes of a Sound Rate Structure" developed by James Bonbright in *Principles of Public Utility Rates*. Each of these principles plays an important role in analyzing the proposals developed in my testimony. To understand the role these principles play, the following discusses each of the principles.

The principle of efficiency broadly incorporates both economic and technical efficiency. As such, this principle has both a pricing dimension and an engineering dimension. Economically efficient pricing promotes good decision-making by gas producers and consumers, fosters efficient expansion of delivery capacity, results in efficient capital investment in customer facilities and facilitates the efficient use of existing pipeline, storage and distribution resources. The efficiency principle benefits stakeholders by creating outcomes for regulation consistent with the long-run benefits of competition while permitting the economies of scale consistent with the best cost of service.

The cost of service and value of service principles each relate to designing rates that recover the total revenue requirement without causing inefficient choices by consumers. The cost of service principle contrasts with the value of service principle when certain transactions do not occur at price levels determined by embedded cost of service. In essence, the value of service acts as a ceiling on prices. Where prices are set at levels higher than the value of service, consumers will not purchase the service.

The calculation of a "true" cost of service is complicated by the fact that for network industries like the natural gas distribution industry, the provision of public utility service often involves joint and common costs which must be allocated (rather than directly assigned) to specific customer classes or rate schedules to develop a full cost of service study. While a good fully distributed cost of service analysis can be performed using principles of cost causation, informed judgment is nonetheless required to perform such a study. A fully distributed cost of service study, properly reflecting cost causation principles and employing sound methods, provides a reasonable tool for the allocation of the total revenue requirement to customer classes (interclass distribution) and within the customer classes (intraclass distribution).

The principle of stability typically applies to customer rates. This principle suggests that reasonably stable and predictable prices are important objectives of a proper rate design. This may mean that changes in rate design may need to be phased in through a planned set of changes that occur over in a series of planned steps.

The concept of non-discrimination requires prices designed to promote fairness and avoid undue discrimination. Fairness requires no undue subsidization either between customers in the same class or across different classes of customers. This principle is best stated by noting that customers who receive the same service and use the same facilities should pay the same rates for such service.

This principle recognizes that the ratemaking process requires discrimination where there are factors at work that cause the discrimination to be useful in accomplishing other objectives. For example, things like the location, type of meter and service, demand characteristics, size, and a variety of other considerations are often recognized in the design of utility rates to properly distribute the total cost of service to and within customer classes.

The principle of administrative simplicity as it relates to rate design requires prices reasonably simple to administer and understand. This concept includes price transparency within the constraints of the ratemaking process. Prices are transparent when customers are able to reasonably calculate and predict bill levels and interpret details about the charges resulting from the application of the tariff.

Finally, there is the critical principle that rate design permits the utility a reasonable opportunity to recover the allowed revenue requirement based on the cost of service. Proper design of utility rates is a necessary condition to enable an effective opportunity to recover the cost of providing service included in the revenue authorized by the regulatory authority. This principle is very similar to the stability objective that I previously discussed from the perspective of customer rates.

As Bonbright discusses, these principles, like most principles that have broad application, can compete with each other. This competition or tension requires further judgment to strike the right balance between the principles. Detailed evaluation of rate design alternatives and rate design recommendations must recognize the potential and actual competition between these principles. Indeed, Bonbright discusses this tension in detail. Rate design recommendations must deal effectively with such tension. For example, as noted above, there are tensions between cost and value of service principles.

The conflict between good price signals based on marginal cost and a balanced budget or revenue recovery principle arises because marginal cost is below average cost due to economies of scale. Where fixed delivery service costs do not vary with volume of gas sales, marginal costs for delivery equal zero. Marginal customer costs equal the additional cost of providing the entire delivery service to the customer. Marginal cost tends to be either above or below average cost in both the short run and the long run. This means that marginal cost-based pricing will produce either too much or too little revenue to support the revenue requirement.

This suggests that efficient price signals may require a multi-part tariff designed to meet the revenue requirements while sending marginal cost price signals related to consumption decisions. Properly designed, a multi-part tariff may include elements such as:

- Access charge - a fixed monthly charge per customer/meter
- Facility charge- a demand charge or a fixed contract charge based on the costs of local distribution facilities provided for a customer. These facilities may be dedicated with directly assigned costs or shared with costs allocated under the cost of service study
- Demand charges – a demand charge based on the fixed costs of transmission and distribution system costs. The costs are recovered through a demand charge based on either contract demand or the highest daily demand occurring in the last twelve months.
- Consumption charges - volumetric (per m^3) charge to recover variable costs
- Revenue credits- This provision recognizes that certain bill credits may arise as the result of regulatory policies. For example, in some jurisdictions no costs are allocated to industrial customers. Instead, firm customers are credited with all or a portion of the interruptible revenues. Other bill credits may include revenues from capacity release or other rate mechanisms such as earnings sharing under PBR.

In the case of a gas LDC, for residential and small commercial customers the combination of scale economies and class homogeneity permits the use of a single fixed annual charge payable by a monthly charge that meets all of the requirements for an efficient rate and recovers the embedded cost revenue requirement. For larger customers, a combination of these elements permit good price signals and revenue recovery; however, the tariff design becomes more difficult to structure and likely will no longer meet the requirements of simplicity. Therefore, sacrificing some economic efficiency for a customer class in order to maintain simplicity represents a reasonable compromise. For larger customers the added complexity of a demand charge is not a concern.

There are potential conflicts between simplicity and non-discrimination and between value of service and non-discrimination. Other potential conflicts arise where companies face unique circumstances that must be considered as part of the rate design process.

The process of developing rates within the context of these principles and conflicts requires a detailed understanding of all the factors that impact rate design. These factors include:

1. System cost characteristics such as the embedded customer, demand and commodity related costs by type of service;
2. Customer load characteristics such as peak demand, load factor, seasonality of loads, and quality of service;

3. Market considerations such as elasticity of demand, competitive fuel prices, end-use load characteristics and bypass alternatives; and
4. Other considerations such as the value of service ceiling/marginal cost floor, unique customer requirements, areas of under-utilized facilities, opportunities to offer new services and the status of competitive market development.

In addition, the development of rates must consider existing rates and the customer impact of modifications to the rates.

In each case, a rate design seeks to recover the authorized level of revenue based on the actual billing determinants occurring during the test period used to develop the rates. This recovery occurs in the "Rate Effective Period". The Rate Effective Period is the first twelve months after the effective date of new rates. While the rates remain in effect after this period, the concept is used to tie revenue requirements to revenues produced by new rates. Essentially, the revenues in the Rate Effective Period should provide the LDC with a reasonable opportunity to earn the allowed return.

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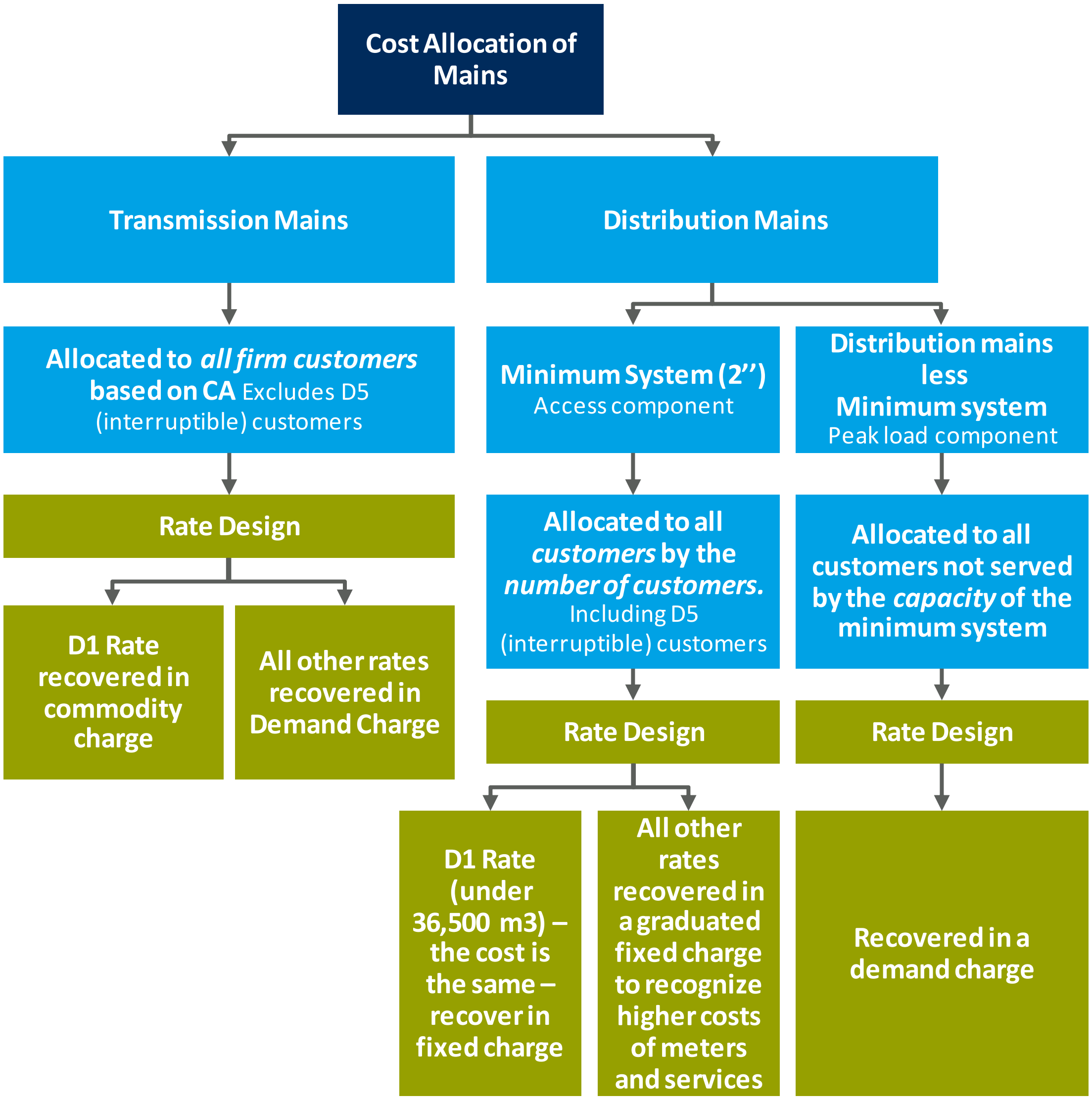
DEMONSTRATION OF TRANSLATING MAINS COSTS TO RATE DESIGN

The following presents an example of how the Black & Veatch proposal for allocating mains costs can be translated into rate design.

Figure 3 Mains Cost from Cost Allocation to Rate Design



The above table repeats the Black & Veatch proposal for allocation of mains. This section makes recommendation of how the allocated cost would appropriately be recovered in rate design.

For Transmission Mains, which have been allocated on a CA basis, costs would be recovered in a demand charge for any rates that have a demand charge. For the D1 rate, the allocated costs would be recovered in the volumetric portion of the rate.

For Distribution Mains, the minimum system component of the cost allocation represents the customer component. These costs should be recovered in a fixed customer charge or access charge. For D1 customers under 36,500 m^3, which can all be served by the minimum system, the customer charge would be set at the allocated revenue requirement for the class of service divided by the number of customers and billed in twelve monthly installments. In some cases regulators have collected this annual cost in unequal payments with lower summer charges and higher winter charges. For all larger customers, the access costs would be recovered in a graduated fixed charge based on the size of meter to recognize the higher costs of meters and services. The capacity portion, which is all distribution main costs not included in the minimum system costs, should be recovered in a demand charge.

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5 Recommendations for Gaz Metro Rate Changes

Based on the Black& Veatch review and in light of the rate design principles and tools discussed, the following recommendations relate to the rates used by Gaz Metro. First, the distribution Rate D_1 is far too complex as a result of the likely level of heterogeneity[13] of the class. Even then, it is also likely that the rate does not accurately track costs for the customers served under the rate. The optimal solution would be to split the rate into several new rates consistent with the subrates concern to be addressed. Black & Veatch recommends the following splits: Small General Service Rate D_0 for customers with annual volumes of approximately 0 to 36,500 m^3; Mid General Service D_1 for customers with annual volumes greater than 36,500 to approximately 365,000 m^3; and Large General Service D_2 for customers with annual consumption larger than 365,000 m^3. These new classes would have simpler rate designs consisting of a distribution access charge and a commodity charge to recover non-distribution costs and variable costs. The largest customers may also have a demand charge. This change will also change the definition of Default Service to be the rate applicable to the customers estimated or actual annual consumption whichever is greater. For rates other than D_0 the rates would have graduated distribution access charges based on meter class and a commodity charge to recover the remainder of the revenue requirement in excess of the access charge recovery. It is likely that these volumetric charges will need to be higher in the winter and lower in the summer to track costs for the higher load factor year round gas customers. The largest customers may also have a demand charge and lower commodity charges than the other customers in the class. (These changes are also more consistent with other gas LDCs in Canada.)

The cross subsidy situation between classes is too high. Following the economic theory, customers have to support their costs. However, we do understand that in the Gaz Métro franchise, in which there are some particularities, it is difficult to have a revenue to cost ration of one for all customer classes. We submit that Gaz Métro has to reduce the inter-class subsidy as much as the different markets could bear.

With respect to the other large customer rates, Black& Veatch suggests the addition of graduated customer charges based on meter and service investment for customers served under the D_3, D_4 and D_5 rates. Simplify the demand charge component (MDO) of the rates to assure intraclass cost recovery is appropriate. This demand should recover the unit demand costs for the class. The current Gaz Metro rate design approximates this general policy with regard to fixed cost recovery. The design of the new distribution rates requires additional discussion. The separation into the small general, mid general and large general service classes is based on the approximate annual volumes even though annual volumes are not a reflection of cost causation and therefore results in an inefficient basis for class determination. Essentially, the delivery costs for all of these customers represents a fixed annual cost caused by system access only for the smallest customers and a combination of system access and design day demand for larger customers. For costs classified as distribution costs all of the costs are fixed except for a small amount of operational costs associated

[13] Heterogeneity means that the class contains customers whose load and cost characteristics differ across the class. Ideally, utilities design simple rates for homogeneous classes of service. For example residential and the smallest general service customers are homogeneous because they use the same main, service line meter and regulator. In addition, these customers use gas for the same types of end use applications and in very similar load patterns. For larger commercial customers, there costs are different because they use different meters, regulators and size of main and service. In addition commercial customers have different load patterns and end-use equipment. For example a commercial cleaner has a year round load associated with cleaning and drying.

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with the odorization of the gas. (This number is so small relative to the remainder of the distribution costs that it could be ignored for purposes of rate simplicity if there were no other volumetric costs associated with storage and transmission costs.) The access charge for small customers is not currently cost based because as discussed above, the system access costs are the same for small customers who use the same meter, regulator, service line and minimum size of main on average. Currently, rates recover a significant portion of the system's fixed cost based on the volume of consumption. This means that customers with below average consumption for the class pay less than the cost of service and larger than average customers pay more than the cost of service. This intra-class subsidization has implications for just and reasonable rates and also importantly for competitive market considerations and economic efficiency.

The existence of this cross subsidy results in rate discrimination that fits the classic definition of undue discrimination. The classic definition is as follows: any discrimination between customers as to the rate charged for the *same service under like conditions* results in undue discrimination. As a practical matter the issue of undue discrimination is a factual issue based on the characteristics of the service provided. In the case of the portion of the current D_1 rate that represents the smallest customers, the current rates result in different charges for customers receiving the same service-gas delivery- and under the same conditions in terms of the facilities used paying widely different rates for that service. By instituting an access charge to recover the fixed costs, rates will reflect cost causation and avoid undue discrimination.

Ultimately, all customers will benefit from the new rate design. To develop rate classes under D_1 the new customer classes will best be defined based on the meter installed to serve the customer. Gaz Metro would develop a set of meters used for smaller customers with approximately equal costs. Each classification would be based on the meter class regardless of annual consumption. Each meter class would have its own annual distribution access charge payable in twelve installments. The commodity charge for each group would be the same based on the cost of odorization and transmission services. For the larger classes within the current D_1 rate, it will be necessary to separate the higher load factor customers so that they will not pay too much for transmission costs that are recovered volumetrically. In addition, for customers taking a bundled service the cost of gas supply would continue to be a volumetric charge. This may be accomplished, for example, by having either a declining block commodity charge during the summer so that excess summer usage is billed at a lower commodity rate to reflect the lower cost per unit of consumption for higher load factor customers within the class or a seasonally differentiated flat charge for winter and summer with the summer charge being much lower than the winter charge. The rate design for rates D_3, D_4 and D_5 would consist of graduated customer charges based on the cost of meter and service plus other customer related costs. The demand charge would recover the fixed cost of distribution, transmission assets and the commodity charge would recover only variable costs (odorization). This rate design encourages higher load factors for all customers and tracks cost more precisely

HYPOTHETICAL RATE DESIGNS BASED ON THE BLACK & VEATCH PROPOSAL

For purposes of understanding the Black & Veatch proposals we have designed hypothetical rates to reflect the results of the proposals above. In each case, the proposed rates are for illustration and do not reflect the results for actual Gaz Metro analysis including cost of service, revenue or billing determinants. The purpose is to illustrate the rate forms not the actual results.

General Service Rate D_0

RATE CLASS	ANNUAL ACCESS CHARGE	MONTHLY ACCESS CHARGE	MONTHLY CHARGE PER m^3
Based on Meter type	$240 per year	$20.00	$0.40 per m^3

Under Rate D_0 the annual charge is determined as the non-volumetric revenue requirements divided by the number of customers on the rate schedule (residential and small commercial with the same type of meter). Customers would be billed each month at the rate of $20 plus ($0.40*m^3). The customer would be responsible for the annual charge over the twelve month period for the premise even if the customer turned off gas service in the summer and returned in the fall for service to be turned on again.

General Service Rate D_1

RATE CLASS	ANNUAL ACCESS CHARGE	MONTHLY ACCESS CHARGE	MONTHLY CHARGE PER m^3
Meter Type A	$300 per year	$25.00	$0.60 per m^3 Winter (8Months) $0.10 m^3 Summer
Meter Type B	$480 per year	$40.00	$0.60 per m^3 Winter (8Months) $0.10 m^3 Summer
Meter Type C	$600 per year	$50.00	$0.60 per m^3 Winter (8Months) $0.10 m^3 Summer

Under Rate D_1 the annual charge is determined in the same fashion as Rate D_0. The annual charge is paid on a monthly basis. The charge per m^3 is based on collecting most of the volumetric costs for the class in the winter months. This value is set at 100 percent of the transmission related revenue requirement plus the load weighted volumetric costs such as compressor plant and O&M costs. If for example the winter volume for this class represented 75% of these costs than 75% of the revenue requirement would be added to the winter rate and 25% would be used for the summer rate. Rate D_2 would look like Rate D_1 with higher access charges and with the potential for a demand charge to be included resulting in lower charges per m^3 based solely on the variable volumetric charges.

Rate D_3

RATE CLASS	ANNUAL CHARGE	MONTHLY ACCESS CHARGE	MONTHLY SUBSCRIBED VOLUME CHARGE	MONTHLY CHARGE PER m^3
Meter Type A	$1200	$100	$2.00 per m^3	$0.10 m^3
Meter Type B	$3600	$300	$2.00 per m^3	$0.10 m^3
Meter Type C	$12000	$1000	$2.00 per m^3	$0.10 m^3

Under Rate D_3 the access charge is graduated based on local facilities, the subscribed volume charge recovers all design day demand costs based revenue requirements and the monthly charge recovers the volumetric related costs. Rates D_4 and D_5 would be similar with several additional provisions. To the extent that costs are directly assignable for local facilities these schedules would replace the access charge with a facilities rental charge that recovers the carrying cost plus expenses for customers with direct assignments of cost for local facilities. If the facilities cannot be directly assigned, the graduated access charge would be applied base on the metering costs and the other access related costs allocated to the class. Metering is typically customer specific in this class so the meter component would be added to the other class related access costs to develop the access charge for each customer. The subscri9bed volume charge would be based on all of the demand related cost for the class including distribution and transmission for Rate D_4 and distribution costs alone for$Rate\ D_5$. The monthly m^3 charge would cover any volumetric related costs not recovered in the cost of gas or delivery service charges.

The level of charges under each rate schedule should be tied as closely as possible to the cost of service study. Recognizing that the cost study revenue requirements may not match the actual class revenue requirements, the adjustment for additional revenues would be made to the subscribe volume charge. It is important that the m^3 charge actually reflects variable costs. For that reason any required revenue adjusts for demand billed customers should occur within the demand charge leaving the access charge and the volume charge to be cost based. In some instances, it may be necessary to adjust the demand charge within a class to a lower level for larger customers where the largest customers use only a limited portion of the distribution system.

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6 Review of Other Company Rate Designs

Black & Veatch has collected the tariff from 53 gas LDCs in the US and Canada. The companies included from Canada represent 10 companies some with multiple service areas each with their own tariffs. These tariffs represent a broad selection of gas LDCs serving differing service territories and number of customers. The initial sample was designed to include companies in the northern US and Canada. These utilities also serve both urban and suburban service areas. We narrowed our analysis of the tariff details to the Canadian utilities regardless of size and heating degree days (HDDs) plus US utilities of similar size and HDDs. Appendix B contains the details of each tariff summary, along with three sample delivery rates. The goal was to present delivery rates for residential, general service, and large general service customers.

The following tables provide certain basic information related to the selected utilities:

Table 6 The Utilities and the Number of Customers

COMPANY	NUMBER OF CUSTOMERS	NUMBER OF RATES
ALTA GAS UTILITIES	72,000	4
ATCO GAS	1,000,000	6
ENBRIDGE GAS DISTRIBUTION INC.	1,900,000	14
FORTIS BC	1,100,000	7
GAZIFÈRE	38,500	9
HERITAGE GAS	4,000	3
MANITOBA HYDRO	267,000	6
PACIFIC NORTHERN GAS LTD	40,000	7
SASKENERGY INCORPORATED	358,000	6
UNION GAS LIMITED	1,400,000	21
YANKEE GAS SVC CO	208,000	6
SOUTHERN CONNECTICUT GAS COMPANY	165,000	13
INTERMOUNTAIN GAS COMPANY	305,000	5
COLUMBIA GAS OF MASSACHUSETTS	300,000	28
SEMCO ENERGY GAS COMPANY	286,000	3
MICHIGAN GAS UTILITIES CO	165,000	5
MINNESOTA ENERGY RESOURCES	211,000	16
ROCHESTER GAS AND ELEC CORP	303,000	10
NEW YORK STATE ELEC AND GAS CORP	261,000	16
CASCADE NAT GAS CORP	262,000	12
MADISON GAS ELEC CO	144,000	15

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As the table illustrates, with the exception of the very large and very small Canadian gas LDCs, the companies are reasonably similar in size to Gaz Metro. The table also illustrates the wide variability in the number of rate schedules for each company ranging from 3 to 28.

Table 7 provides a summary of fixed charge recovery for the residential and general service classes of the sample utilities.

Table 7 Fixed Charges for Residential and General Service Customers

COMPANY	RESIDENTIAL FIXED MONTHLY CHARGE	GENERAL SERVICE FIXED MONTHLY CHARGE
CANADIAN UTILITIES		
ALTA GAS UTILITIES	$31.05	$31.05
ATCO GAS	$23.04 (S), $26.67 (N)	$23.04(S), $26.67 (N)
ENBRIDGE GAS DISTRIBUTION INC.	$20.00	$70.00
FORTIS BC	$11.67	$24.48
GAZIFÈRE	$10.05	$17.13
HERITAGE GAS	$21.87	$21.87
MANITOBA HYDRO	$14.00	$14.00
PACIFIC NORTHERN GAS LTD	$10.75	$25.00
SASKENERGY INCORPORATED	$18.85	$31.95
UNION GAS LIMITED	$21.00	$70.00
UNITED STATES UTILITIES		
YANKEE GAS SVC CO	$18.50	$46.00
SOUTHERN CONNECTICUT GAS COMPANY	$17.00	$35.00
INTERMOUNTAIN GAS COMPANY	$2.50 Summer, $6.50 Winter	$2.00 Summer, $9.50 Winter
COLUMBIA GAS OF MASSACHUSETTS	$10.94	$17.51
SEMCO ENERGY GAS COMPANY	$11.50	$11.50
MICHIGAN GAS UTILITIES CO	$11.00	$33.00
MINNESOTA ENERGY RESOURCES CORPORATION	$8.50	$14.50
ROCHESTER GAS AND ELEC CORP	$17.25	$17.25
NEW YORK STATE ELEC AND GAS CORP	$17.03	$24.33
CASCADE NAT GAS CORP	$4.00	$10.00
MADISON GAS ELEC CO	$12.00	$20.79

There are several observations related to Table 7 that should be noted. First, Canadian utilities typically have higher fixed cost charges than the comparable US LDCs, as seen by the average residential charge of $18.23 for the Canadian utilities versus $11.84 for U.S. utilities. There are two related reasons for this observation. First, Canadian regulatory agencies typically adhere more closely to the principle of cost causation than do the states with comparable heating degree days. Second, the states with very low fixed charge rates typically have decoupling mechanisms in place to allow the utility a reasonable opportunity to recover costs including return of and on rate base. The important point to emphasize regarding fixed cost recovery is that the cost of distribution access for small general service customers is the same whether they use one GJ or a hundred. The current Gaz Metro rates do not reflect this fundamental fact but result in a large intraclass subsidy that punishes larger users for the benefit of smaller users.

With respect to fixed cost recovery in other classes of service, the LDCs included in the report have higher fixed monthly charges for larger customers and many include a demand charge for the largest customers. Since nearly all costs for larger customers are fixed based on design day demand or use of storage and transmission capacity, the use of the customer and demand charge is reflective of cost causation.

One important point we should note relative to reviewing rates of other companies is that it is impossible to compare the costs and thus the rate levels for LDCs for many reasons. For example, factors such as HDDs, customer mix, demographics of the service area, costing differences and so forth will significantly impact the rate levels for various LDCs. Just as an example, we have collected data from a number of LDCs related to the installed cost of main by size over the last few years. Installed cost of main by pipe size varies widely. For two inch main, the cost per foot from a number of studies we have conducted ranges from a low $3.11 to a high $39.69 and we have not made these estimates for any of the highest cost regions in the United States. Based on 2008 data from the Handy Whitman Index, the regional variation of main costs from high to low cost region is about 11.5 percent for plastic mains. Within the regions the variance is even larger.

ADDITIONAL SAMPLE RATE DESIGNS THAT DEMONSTRATE COST CAUSATION

The following table provides some selected samples of other LDC rate designs that reflect cost causation and create rates that match cost and revenues. These rate designs were not specifically selected from the list of utilities in the survey, but selected to point out specific components of their rate design that meet cost causation principles.

As Table 8 illustrates, the best practice for larger customers is a demand and customer charge with a relatively low commodity charge recovering actual variable charges.

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Table 8 Selected Rate Design Elements

COMPANY	RATE ELEMENTS
COLUMBIA GAS DIST CO of PA Key Rate Design element: • Graduated Customer Charges for large customers	LARGE GENERAL SERVICE Monthly Customer Charge $ Annual Throughput < 107,300 thms $ 125.12 Annual Throughput >= 107,300 thms but < 536,489 thms $ 469.34 Annual Throughput >= 536,489 thms but < 1,072,989 thms $ 1,149.00 Annual Throughput >= 1,072,989 thms but < 3,219,000 thms $ 2,050.00 Annual Throughput >= 3,219,000 thms but < 7,510,990 thms $ 4,096.00 Annual Throughput > 7,510,989 thms $ 7,322.00
Alta Gas Utilities Key Rate Design element: • Demand Charge • clear definition of maximum demand	Optional Demand General Service - Rate No. 3 Distribution (Base): $24.247/day Default Supply Provider Admin. Fee: $0.068/day Demand Charge: $0.240/day/GJ of Billing Demand The Billing Demand shall be the greater of: 100 GJ, or The Contract Demand, or The greatest amount of gas in GJ in any consecutive 24-hour period during the current and preceding eleven billing periods provided that the greatest amount of gas delivered in any 24 consecutive hours in the summer period (April 1 to October 31) shall be divided by 2. Variable Distribution (Base) Energy Charge: $0.025/GJ
Atlanta Gas Light Key Rate Design elements: • Graduated Customer Charge • Demand Charge	General Gas Delivery Service (G-11) Annual Customer Charge Design Day of less than 2.5 Dth (per Customer) $ 240.00 Design Day greater than or equal to 2.5 and less than 7 (per Customer) 480.00 Design Day greater than or equal to 7 and less than 20 (per Customer) 540.00 Design Day greater than or equal to 20 and less than 200 (per Customer) 900.00 Design Day greater than or equal to 200 (per Customer) 2,100.00 Dedicated Design Day Annual Capacity Charge (per Dth) 88.68 Annual Peaking Service Charge if applicable (see below) Annual Meter Reading Charge 8.52
Northern States Power Company Key Rate Design elements: • Differentiated Customer Charge • Low Commodity Charge • Demand Charge	MONTHLY MINIMUM CHARGE Customer Charge plus the Demand Charge as listed below. RATE — SMALL — LARGE Customer Charge per Month — $150.00 — $275.00 Distribution Charge per Therm — $0.047512 — $0.047512 Distribution Demand Charge per $0.80947 $0.80947 Therm per Month of Billing Demand

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Appendix A—Theoretical Literature Related to Pricing and Cost of Service

Texts:

1. *Principles of Public Utility Rates,* James C. Bonbright
2. *Principles of Public Utility Rates,* 2nd Edition, James C. Bonbright, Albert l. Danielson, David R. Kamerschen
3. *Principles of Public Utility Regulation,* A. J. G. Priest
4. *The Regulation of Public Utilities,* Charles F. Phillips, Jr.
5. *The Economics of Regulation,* Alfred E. Kahn
6. *Gas Rate Fundamentals,* American Gas Association
7. *Gas Distribution Rate Design Manual,* NARUC
8. *Fairness or Efficiency*, Edward E. Zajac
9. *The Theory of Public Utility Pricing,* Stephen J. Brown, David S. Sibley
10. *Contestable Markets and the Theory of Industry Structure,* William J. Baumol, John C. Panzar, Robert D. Willig
11. *Overhead Costs,* W. Arthur Lewis
12. *Operational Economics of Public Utilities,* Constantine W. Bary
13. *Nonlinear Pricing,* Robert B. Wilson
14. *The Process of Ratemaking*, Leonard Saul Goodman

Articles:

1. "A Contribution to the Theory of Taxation", Frank P. Ramsey *Economic Journal* (March 1927)
2. "The Marginal Cost Controversy", R. H. Coase *Economica* 1946
3. "The Two-part Tariff", W. A. Lewis *Economica* 1941
4. "The Theory of Public Utility Pricing and Its Application", R. H. Coase *Bell Journal of Economics and Management Science* (Spring 1970)
5. "Equity and Efficiency in Public Sector Pricing: The Optimal Two-part Tariff" Martin S. Feldstein, *Quarterly Journal of Economics"* (May 1972)
6. "Fixed Cost Recovery: An Inconvenient Truth", H. Edwin Overcast, American Gas June 2007

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Appendix B—Rate Survey of Canadian and Regional U.S. LDC Delivery Rates

Appendix B
LDC Distribution Rate Survey

Area	Company	Service Area	Number of customers	Rates	Rates Effective	Rate 1	Rate 2	Rate 3
Alberta, Canada	Alta Gas Utilities	90 communities across Alberta thabasca, Barrhead, Bonnyville, Drumheller, Hanna, Three Hills, Grande Cache, High Level, Morinville, Leduc, Pincher Creek, Dunmore and area, Stettler, St. Paul, Two Hills, Elk Point and Westloc	72,000	Small General Service Optional Large General Service - applies to our large customers who use more than 6,250 GJ of natural gas per year. Optional Demand Service - applies to our largest of customers who use more than 12,980 GJ of natural gas per year. Optional Irrigation Pumping Service	3/28/2013	**SMALL GENERAL SERVICE** Distribution (Base): $ 1.0350/Day Default Supply Provider Admin. Fee: $ 0.075/Day Variable Distribution (Base) Energy Charge: $ 1.833/GJ	**Large General Service - Rate No. 2** Distribution (Base): $11.203/day Default Supply Provider Admin. Fee: $0.071/day Variable Distribution (Base) Energy Charge: $1.145/GJ	**Optional Demand General Service - Rate No. 3** Distribution (Base): $25.847/day Default Supply Provider Admin. Fee: $0.072/day Demand Charge: $0.256/day/GJ of Billing Demand The Billing Demand shall be the greater of: 100 GJ, or The Contract Demand, or The greatest amount of gas in GJ in any consecutive 24-hour period during the current and preceding eleven billing periods provided that the greatest amount of gas delivered in any 24 consecutive hours in the summer period (April 1 to October 31) shall be divided by 2. Variable Distribution (Base) Energy Charge: $0.026/GJ
Alberta, Canada	ATCO Gas	ATCO Gas, an Alberta-based, province-wide natural gas distribution company. serves more than one million customers in nearly 300 Alberta communities.	1 million	Low Use Delivery Service Low Use Interim Rider Low Use Transmission Service Charge Rider T Low Use Weather Deferral Account Rider W Mid Use Delivery Service (1200 -8000 GJ/YR) Mid Use Interim Rider Mid Use Transmission Service Charge Rider T Mid Use Weather Deferral Account Rider W High Use Delivery Service (>8000 GJ/YR) High Use Interim Rider S High Use Transmission Service Charge Rider T	4/1/2013	**Low Use Delivery Service (<1200 GJ/YR) South** Fixed Charge (daily) 0.768 Variable Energy ($/GJ) 0.703 **Low Use Delivery Service (<1200 GJ/YR) North** Fixed Charge (daily) 0.889 Variable Energy ($/GJ) 0.793	**Mid Use Delivery Service (1200-8000 GJ/YR) South** Fixed Charge (daily) 0.768 Variable Energy ($/GJ) 0.682 **Mid Use Delivery Service (1200 -8000 GJ/YR) North** Fixed Charge (daily) 0.889 Variable Energy ($/GJ) 0.833	**High Use Delivery Service (>8000 GJ/YR) South** Fixed Charge (daily) 4.588 Variable Charge ($/GJ) 0.00 24 Hour Demand ($/GJ/day) 0.143 **High Use Delivery Service (>8000 GJ/YR) North** Fixed Charge (daily) 5.137 Variable Charge ($/GJ) 0.00 24 Hour Demand ($/GJ/day) 0.168
Ontario, Canada	Enbridge Gas Distribution Inc.	Ontario – mainly in Southern and Eastern Ontario.	1.9 million	RESIDENTIAL SERVICE CONTAINER SERVICE FIRM CONTRACT SERVICE LARGE VOLUME LOAD FACTOR SERVICE EXTRA LARGE FIRM DISTRIBUTION SERVICE SEASONAL FIRM SERVICE INTERRUPTIBLE SERVICE LARGE INTERRUPTIBLE SERVICE WHOLESALE SERVICE FIRM OR INTERRUPTIBLE DISTRIBUTION SERVICE GAS STORAGE SERVICE BACKSTOPPING SERVICE TRANSMISSION, COMPRESSION AND POOL STORAGE SERVICE TECUMSEH TRANSPORTATION SERVICE	7/1/2013	**RESIDENTIAL RATES** Customer Charge $20 Gas Supply Charge 9.846 ¢/m Amount of gas used per month in cubic metres (m^3) First 30 - 8.3011 ¢/m^3 Next 55 - 7.8402 ¢/m^3 Next 85 - 7.479 ¢/m^3 Over 170 - 7.210 ¢/m^3	**Rate 6 - Commerical and Industrial** Monthly Customer Charge $70.00 Delivery Charge per cubic metre For the first 500 m^3 per month 8.074 ¢/m^3 For the next 1050 m^3 per month 6.3914 ¢/m^3 For the next 4500 m^3 per month 5.2134 ¢/m^3 For the next 7000 m^3 per month 4.4561 ¢/m^3 For the next 15250 m^3 per month 4.1199 ¢/m^3 For all over 28300 m^3 per month 4.0355 ¢/m^3	**Rate 110 - LARGE VOLUME LOAD FACTOR SERVICE** Monthly Customer Charge $587.37 Delivery Charge Per cubic metre of Contract Demand 22.9100 ¢/m^3 Per cubic metre of gas delivered For the first 1,000,000 m^3 per month 0.5833 ¢/m^3 For all over 1,000,000 m^3 per month 0.4333 ¢/m^3
British Columbia, Canada	FortisBC	south and central BC	1.1 million	RESIDENTIAL SERVICE RESIDENTIAL BIOMETHANE SERVICE SMALL COMMERCIAL SERVICE SMALL COMMERCIAL BIOMETHANE SERVICE LARGE COMMERCIAL SERVICE LARGE COMMERCIAL BIOMETHANE SERVICE SEASONAL FIRM GAS SERVICE	7/1/2013	**RESIDENTIAL SERVICE (Lower Mainland)** Basic Charge per Day $ 0.3890 Delivery Charge per Gigajoule $ 3.397	**Rate 2 SMALL COMMERCIAL SERVICE <2000 GJ Annually (Lower Mainland)** Basic Charge per Day $ 0.8161 Delivery Charge per Gigajoule $ 2.775	**Rate 3 LARGE COMMERCIAL SERVICE (Lower Mainland)** Basic Charge per Day $ 4.3538 Delivery Charge per Gigajoule $ 2.344

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Quebec, Canada	Gazifère	Gazifère serves the broad expanse of land between Fort-Coulonge, Montebello and Grand-Remous. Its coverage territory currently includes the city of Gatineau,	38,500	RATE 1 – GENERAL SERVICE RATE 2 – RESIDENTIAL AND INSTITUTIONAL SERVICE RATE 3 – LOW VOLUME FIRM SERVICE RATE 4 – MODERATE VOLUME FIRM SERVICE RATE 5 – LARGE VOLUME FIRM SERVICE RATE 6 – VERY LARGE VOLUME FIRM SERVICE RATE 7 – NATURAL GAS FOR VEHICLES RATE 8 – SEASONAL SERVICE RATE 9 – INTERRUPTIBLE SERVICE NATURAL GAS COST ADJUSTMENT RIDER GREEN FUND DUTY RIDER	7/1/2013	**RATE 2 - RESIDENTIAL SERVICE** MONTHLY FIXED CHARGE $10.05 Delivery charge 24.81 ¢/m³ for the first 50 m³ (from 0 to 50 m³); 24.09 ¢/m³ for the next 50 m³ (from 50 to 100 m³); 23.38 ¢/m³ for the next 220 m³ (from 100 to 320 m³); 22.68 ¢/m³ for the next 680 m³ (from 320 to 1,000 m³); 21.95 ¢/m³ in excess of 1,000 m³	**RATE 1 - GENERAL SERVICE** MONTHLY FIXED CHARGE $17.13 Delivery charge 20.52 ¢/m³ for the first 100 m³ (from 0 to 100 m³); 19.40 ¢/m³ for the next 220 m³ (from 100 to 320 m³); 18.31 ¢/m³ for the next 680 m³ (from 320 to 1,000 m³); 17.17 ¢/m³ for the next 2,200 m³ (from 1,000 to 3,200 m³); 14.98 ¢/m³ for the next 6,800 m³ (from 3,200 to 10,000 m³); 13.32 ¢/m³ in excess of 10,000 m³	**RATE 5 - LARGE VOLUME FIRM SERVICE** Monthly fixed charge 31.76 ¢/m³ of the subscribed volume or, as the case may be, of the variable daily volume Delivery charge 3.52 ¢/m³ for all volumes withdrawn
Nova Scotia, Canada	Heritage Gas	Halifax, Dartmouth, Stanfield International Airport and Amherst	4,000	Residential Rate Class 1 - Up to 5000 GJ per year Rate Class 2 - Between 5001 and 50000 GJ per year Rate Class 3 - Over 50000 GJ per year	8/1/2013	**RESIDENTIAL** Fixed Monthly Customer Charge $21.87 Base Energy Charge (per GJ/month) $8.401	**GENERAL SERVICE - RATE CLASS 1 (UP TO 5000 GJ/YEAR)** Fixed Monthly Customer Charge $21.87 Base Energy Charge (per GJ/month) $8.401	**GENERAL SERVICE - RATE CLASS 2 (5001 - 50,000 GJ/YEAR)** Fixed Monthly Customer Charge $562.83 Base Energy Charge (per GJ/month) $2.508
Manitoba, Canada	Manitoba Hydro	southern Manitoba	267,000	Residential Small General Service Commercial Large General Service High Volume Firm Service Mainline Firm Service Interruptible Service	8/1/2013	**RESIDENTIAL** Basic Monthly Charge ($/month) $14.00 Distribution to Customer ($/m3) $0.0848	**Small General Service Commercial Rates** Basic Monthly Charge ($/month) $14.00 Distribution to Customer ($/m3) $0.0848	**Large General Service Rates** Basic Monthly Charge ($/month) $77.00 Distribution to Customer ($/m3) $0.0320
BC, Canada	Pacific Northern Gas Ltd	Pacific Northern Gas Ltd ("PNG") delivers natural gas to customers in west-central British Columbia, and through its subsidiary Pacific Northern Gas (N.E.) Ltd. ("PNG (N.E.)"), to customers in the province's northeast.	40,000	Residential Service Small Commercial Service Large Commercial Service Industrial Service Commercial Interruptible Service Seasonal Service Natural Gas Vehicle Service	1/1/2013	**PNG West Service Area Residential Service** Basic Charge $10.75/month Delivery Charge $11.830/GJ Company Use Rider $0.043/GJ RSAM Rider $(0.111)/GJ	**PNG West Service Area Small Commercial Service** Basic Charge $25/month Delivery Charge $10.004/GJ Company Use Rider $0.043/GJ RSAM Rider $(0.111)/GJ	**PNG West Service Area Large Commercial Service** Basic Charge $150.00/month Delivery Charge $8.06/GJ Company Use Rider $0.043/GJ
Saskatchewan, Canada	SaskEnergy Incorporated	Saskatchewan	358,000	Residential Service Farm Service General Service II General Service III Small Industrial Contract Industrial	7/1/2012	**Residential Service** **Delivery Service** Basic Monthly Charge $18.85 Delivery Charge 7.10¢/m3	**Commercial Small** **Delivery Service** Basic Monthly Charge $31.95 Delivery Charge 6.31¢/m	**Small Industrial** **Full Service** Basic Monthly Charge $216.00 Delivery Charge: First 40,000m3/Mo. 3.90¢/ m3 Balance 3.33¢/ m3
Ontario, Canada	Union Gas Limited	northern, southwestern and eastern Ontario	1.4 million	Distribution Contract Commercial/Industrial Rate Schedules Northern and Eastern Rates Rate 01 - Small Volume General Firm Service Rate 10 - Large Volume General Firm Service Rate S1 - General Firm Service Storage Rates Rate 20 - Medium Volume Firm Service Rate 25 - Large Volume Interruptible Rate 30 - Intermittent Gas Supply Service and Short Term Storage/Balancing Service Rate 77- Wholesale Transportation Service Rate 100 - Large Volume High Load Factor Firm Service Southern Rates Rate M1 - Small General Service Rate Rate M2 - Large General Service Rate Rate M4 - Firm Industrial and Commercial Contract Rate Rate M5A - Interruptible Industrial and Commercial Contract Rate Rate M7 - Special Large Volume Industrial and Commercial Contract Rate Rate M9 - Large Wholesale Service Rate Rate M10 - Small Wholesale Service Rate Rate R1 - Bundled Direct Purchase Contract Rate Rate T1 - Storage and Transportation Rates for Contract Carriage Customers Rate T3 - Storage and Transportation Rates for Contract Carriage Customers Rate U2 - Storage rates for Unbundled Customers Rate U5 - Storage and Transportation Rates for Unbundled Customers Rate U5 Schedule - full description of Rate U5	7/1/2013	**RESIDENTIAL EASTERN, NORTHERN, NORTHWESTERN, FORT FRANCES ONTARIO** Delivery First 100 m3 9.7803 ¢/m3 Next 200 m3 9.2558 ¢/m3 Next 200 m3 8.8831 ¢/m3 Next 500 m3 8.5411 ¢/m3 All Over 1,000 m3 8.2586 ¢/m3 Delivery Price Adjustment 0.2822¢/m3 Monthly Charge $21.00 RESIDENTIAL SOUTHERN ONTARIO Delivery First 100 m3 3.8051 ¢/m3 Next 150 m3 3.5986 ¢/m3 All Over 250 m3 3.1101 ¢/m3 Delivery Price Adjustment 0.50049¢/m3 Monthly Charge $21.00	**Rate 10 - Large Volume General Firm Service N, E, NW, FF** Monthly Charge - All Zones $70.00 Monthly Delivery Charge - All Zones First 1,000 m3 7.7446 Next 9,000 m3 6.3310 Next 20,000 m3 5.5248 Next 70,000 m3 5.0087 Over 100,000 m3 3.0535 Delivery - Price Adjustment (All Volumes) (4.3773)	**Rate 20 - Medium Volume Firm Service N, E, NW, FF** Monthly Charge - All Zones $1000.00 **DELIVERY CHARGES** (cents per month per m3) Monthly Demand Charge for first 70,000 m3 of Contracted Daily Demand 27.8179 Monthly Demand Charge for all units over 70,000 m3 of Contracted Daily Demand 16.3583 Commodity Charge for first 852,000 m3 of gas volumes delivered 0.5440 Commodity Charge for all units over 852,000 m3 of gas volumes delivered 0.3996

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Connecticut, USA	YANKEE GAS SVC CO	http://www.yankeegas.com/downloads/	208,000	Residential Heating Residential Non-heating Residential Multi-family Small General Firm Service Medium General Firm Service Large General Firm Service	11/1/2012	**Residential Non-Heating - Rate 1** Customer Service Charge $18.50 per month Delivery Charge $1.4588 per Ccf Residential Heating - Rate 2 Customer Service Charge $15.00 per month Delivery Charge: First 30 Ccf - $0.8108 per Ccf All over 30 Ccf - $0.5404 per Ccf	**Small General Firm Service** Customer Service Charge $46.00 per month Daily Demand Meter Charge (optional) $28.00 per month Demand Charge $1.0000 per Ccf of billing demand Delivery Charge First 200 Ccf $.3532 per Ccf All over 200 Ccf $.2055 per Ccf	**Medium General Firm Service** Customer Service Charge $73.00 per month Daily Demand Meter Charge $28.00 per month Demand Charge $2.0000 per Ccf of billing demand Delivery Charge First 1,000 Ccf $.0967 per Ccf All over 1,000 Ccf $.0306 per Ccf
Connecticut, USA	SOUTHERN CONNECTICUT GAS CO	22 Counties in southern Connecticut	165,000	Residential Service General Residential Service Heating Residential Multi-Dwelling Service Small General Service General Service Large General Service Manufacturers Gross Receipt Tax Credit Economic Development Manufacturing Economic Development Rider Manual Interruptible Service; Natural Gas Vehicles Transportation Receipt Service Balancing Service Stanby Service Storage Service Rate Optional Long Haul Service Distributed Generation Rebate Rider Capacity Release Service Peaking Service Rate As-Available Gas Supply Service	11/1/2012	**RESIDENTIAL SERVICE HEATING** ***Delivery Service*** Customer Charge $17.00 per month Delivery Charge $0.8695 per CCF	**SMALL GENERAL SERVICE** for annual consumption between 0 to 4,999 CCF Customer Charge: $35.00 per month Demand Charge: $0.40 per ccf of maximum daily demand Delivery Charge: for first 100 ccf: $0.6030 per ccf Delivery Charge for over 100 ccf $0.1710 per ccf	**LARGE GENERAL SERVICE** for commercial and industrial customers with normalized annual consumption 30,000 ccf or greater Delivery Service Customer Charge: $244.00 per month Daily Demand Metering Charge: $6.98 per month Demand Charge: $1.1629 per ccf of maximum daily demand Delivery Charge: first 2,500 ccf $0.1105 per ccf Over 2,500 ccf $0.0298 per ccf
Idaho, USA	INTERMOUNTAIN GAS COMPANY	74 communities in southern Idaho	305,000	RS-1 Residential Service RS-2 Residential Service GS-1 General Service IS-R Interruptible Service IS-C Interruptible Service	10/1/2012	**RESIDENTIAL SERVICE RS-1** April-November Customer Charge $2.50 per bill Commodity Charge $0.85696 per therm* December-March Customer Charge $6.50 per bill Commodity Charge $0.7440 per therm* * Includes: Temporary purchased gas cost adjustment of $(0.02618) Weighted average cost of gas of $0.33489	**RESIDENTIAL SERVICE RS-2 (All Gas Appliances)** April-November Customer Charge $2.50 per bill Commodity Charge $0.702386 per therm* December-March Customer Charge $6.50 per bill Commodity Charge $0.66875 per therm* * Includes: Temporary purchased gas cost adjustment of $(0.02618) Weighted average cost of gas of $0.33489	**GENERAL SERVICE GS-1** April-November Customer Charge $2.00 per bill Commodity Charge: First 200 therms per bill @ $0.72011* Next 1,800 therms per bill @ $0.69838* Over 2,000 therms per bill @ $0.67736* December-March Customer Charge $9.50 per bill Commodity Charge: First 200 therms per bill @ $0.66926* Next 1,800 therms per bill @ $0.64806* Over 2,000 therms per bill @ $0.62760* * Includes: Temporary purchased gas cost adjustment of $(0.02618) Weighted average cost of gas of $0.33489

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Massachusetts, USA	COLUMBIA GAS OF MASSACHUSET	The 65 Massachusetts Cities and Towns Served by Columbia Gas of Massachusetts Southeastern Massachusetts Abington*, Attleboro, Avon, Bellingham, Berkley, Bridgewater, Brockton, Canton, Dighton, Dover, Duxbury, East Bridgewater, Easton, Foxboro, Franklin, Halifax, Hanover, Hanson, Holbrook, Lakeville, Mansfield, Marshfield, Medfield, Medway, Mendon, Middleboro*, Millis, Norfolk, Norton, Norwell, Pembroke, Plympton, Randolph, Raynham, Rehoboth, Scituate, Seekonk, Sharon, Stoughton, Swansea*, Taunton, Walpole, West Bridgewater, Wrentham Western Massachusetts Agawam, Chicopee, East Longmeadow, Easthampton, Granby, Hampden, Longmeadow, Ludlow, Monson, Northampton, Palmer, South Hadley, Southwick, Springfield, West Springfield, Wilbraham Merrimack Valley	300,000	Residential Non-Heating (R-1) Low Income Residential Non-Heating (R-2) Residential Heating (R-3) Low Income Residential Heating (R-4) Commercial & Industrial Service (Low Annual Use / High Peak Period Use) (G-40) Commercial & Industrial Service (Medium Annual Use/High Peak Period Use) (G-41) Commercial & Industrial Service (High Annual Use / High Peak Period Use) (G-42) Commercial & Industrial Service (Extra High Annual Use/High Peak Period Use)(G-43) Commercial & Industrial Service (Low Annual Use / Low Peak Period Use) (G-50) Commercial & Industrial Service (Medium Annual Use / Low Peak Period Use) (G-51) Commercial & Industrial Service (High Annual Use /Low Peak Period Use) (G-52) Commercial & Industrial Service (Extra High Annual Use/Low Peak Period Use)(G-53) Outdoor Gas Lighting Service (L) Non-Heating Firm Transportation Service, Residential (T-R1) Low Income Non-Heating Firm Transportation Service, Residential (T-R2) Heating Firm Transportation Service, Residential (T-R3) Low Income Heating Firm Transportation Service, Residential (T-R4) Firm Transportation Service (Low Annual Use / High Peak Period Use) (T-40)	7/1/2013	**Residential Heating Tariff Rates R&T 3:** Monthly Customer Charge $10.94 ECS $0.00 First 10 therms $0.3341 All usage over 10 therms $0.3798 Distribution Adjustment (DAF) $0.3541 Revenue Decoupling Adj. Factor (RDAF) $0.0282	**C&I Low Annual/Low Winter Tariff Rates G&T 50:** Annual less than 5,000 Monthly Customer Charge $17.51 ECS $0.00 First 20 therms $0.2865 All usage over 20 therms $0.3574 Distribution Adjustment (DAF) $0.1659 Revenue Decoupling Adj. Factor (RDAF) 0.0282 **C&I Low Annual/High Winter Tariff Rates G&T 40:** Annual use less than 5,000 Monthly Customer Charge $17.51 ECS $0.00 First 8 therms $0.3166 All usage over 8 therms $0.3673 Distribution Adjustment (DAF) $0.1659 Revenue Decoupling Adj. Factor (RDAF) 0.0282	**C&I High Annual/Low Winter Tariff Rate G&T 52:** Annual use between 40,000 &249,999 therms Monthly Customer Charge $233.02 ECS $0.00 First 2,500 therms $0.0760 All usage over 2,500 therms $0.0871 Distribution Adjustment (DAF) $0.1659 Revenue Decoupling Adj. Factor (RDAF) $0.0282 **C&I High Annual/High Winter Tariff Rate G&T 42:** Annual use between 40,000 & 249,999 therms Monthly Customer Charge $233.02 ECS $0.00 First 400 therms $0.0768 All usage over 400 therms $0.1064 Distribution Adjustment (DAF) $0.1659 Revenue Decoupling Adj. Factor (RDAF) $0.0282
Michigan, USA	SEMCO ENERGY GAS COMPANY	Southern half of the Michigan's Lower Peninsula (including in and around the cities of Albion, Battle Creek, Holland, Niles, Port Huron, and Three Rivers) and in the central, eastern, and western parts of the state's Upper Peninsula.	286,000	Residential Service Rate General Service Rate Transportatio Service	8/1/2013	**RESIDENTIAL SERVICE RATE** Customer Charge per meter: $11.50 per month Main Replacement Program Charge: $0.42 per month Distribution Charge: $0.17342 per therm	**GENERAL SERVICE 1** Customer Charge per meter: $11.50 per month Main Replacement Program Charge: $0.94 per month Distribution Charge: $0.18203 per therm	**GENERAL SERVICE 2** Customer Charge per meter: $35.00 per month Main Replacement Program Charge: $5.91 per month Distribution Charge: $0.13932per therm
Michigan, USA	MICHIGAN GAS UTILITIES CO	12 counties and 147 communities in southern and western Michigan.	165,000	RESIDENTIAL RATE RESIDENTIAL MULTIPLE FAMILY DWELLING RATE SMALL GENERAL SERVICE RATE LARGE GENERAL SERVICE RATE GAS LIGHTING RATE	2/1/2012	**RESIDENTIAL RATE - GENERAL AND HEATING** Customer Charge $11.00 Distribution Charge $1.5987 per Mcf	**SMALL GENERAL SERVICE RATE - (General and Heating)** Customer Charge $33.00 Distribution Charge $1.1876 per Mcf	**LARGE GENERAL SERVICE RATE - (General and Heating)** Customer Charge $400.00 Distribution Charge $1.0094 per Mcf
Minnesota, USA	Minnesota Energy Resources Corp	51 counties and 165 communities throughout Minnesota	211,000	General Service - Firm Small Volume Interruptible Service Large Volume Interruptible Service Super Large Volume Service	7/1/2013	**RATE SCHEDULE GS - RESIDENTIAL** Customer Charge per Month - $8.50 Distribution Charge @ $0.19754 per therm	**RATE SCHEDULE GS - COMMERCIAL AND INDUSTRIAL** Commercial and Industrial - 1,500 therms or less per Year Customer Charge per Month - $14.50 Distribution Charge @ $0.18525 per therm Commercial and Industrial - Over 1,500 therms per Year Customer Charge per Month – $35.00 Distribution Charge @ $0.16868 per therm	**RATE SCHEDULE LVI-CONSOLIDATED LARGE VOLUME INTERRUPTIBLE SERVICE** Per month: Customer Charge $175.00 per meter Base rate of gas @ $0.46555 per therm Distribution charge @ $0.03568 per therm The rate per therm of daily firm capacity, if any, shall be $0.56880 per MDQ
New York, USA	ROCHESTER GAS AND ELEC CORP	nine-county region centered on the City of Rochester.	303,000	General Service Gas Lighting Service Large Transportation Service General Service - Economic Development Small Transportation Service Non-Residential Distributed Generation Firm Gas Sales Service < 50 MW Firm Gas Transportation Service for Distributed Generation Facilities < 50 MW Residential Distributed Generation Firm Gas Sales Service Residential Distributed Generation Gas Transportation Service General Service – Distribution Service to Electric Generation	9/1/2012	**GENERAL SERVICE** Gas Delivery Charge: Usage Rate First 3 therms or less $16.30 Next 97 therms, per therm $0.23097 Next 400 therms, per therm $0.21538 Next 500 therms, per therm $0.19041 Over 1,000 therms, per therm $0.10859 Bill Issuance Charge: $0.95	**LARGE TRANSPORTATION SERVICE** Gas Delivery Charge: First 1,000 therms or less $1080.00 Next 29,000 therms, per therm $0.06098 Next 70,000 therms, per therm $0.04832 Next 900,000 therms, per therm $0.01869 Over 1,000,000 therms, per therm $0.00964 Bill Issuance Charge: $0.95	

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New York, USA	NEW YORK STATE ELEC AND GAS (	40% of upstate New York	261,000	Residential Sales Service General Sales Service Seasonal Gas Cooling Sales Service Firm Transportation Service Small Firm Transportation Service Residential Firm Aggregation Transportation Service Non-Residential Firm Aggregation Transportation Service Industrial Manufacturing or Processing Purposes Sales Service Non-Residential Distributed Generation Firm Sales Service Residential Distributed Generation Firm Sales Service Transportation Service for Fueling of Natural Gas Vehicles Firm or Limited Firm Negotiated Transportation Service Non-Daily Metered Transportation Monthly Balancing Service Basic Electric Generation Transportation Service	9/1/2012	**PSC No. 87 Service Classification No. 1 - Residential Sales Service Rates** Basic Service Charge: Bill Issuance and Payment Processing $ 0.73 First three therms (low income) $ 16.30 First three therms (non-heating) $ 12.30 First three therms (heating) $ 16.30 Usage Charge: Next 47 therms, per therm $ 0.5193 Over 50 therms, per therm $ 0.1220	**PSC No. 87 Service Classification No. 2 - General Sales Service Rates** Basic Service Charge: Bill Issuance and Payment Processing $ 0.73 First three therms or less $ 23.60 Usage Charge: Next 497 therms, per therm $ 0.3378 Next 14,500 therms, per therm $ 0.1946 Over 15,000 therms, per therm $ 0.1197	**PSC No. 88 Service Classification No. 1 - Firm Transportation Service Rates** Transportation Administration Charge: Bill Issuance and Payment Processing $ 0.73 First 500 therms or less $1,124.19 Usage Charge: Next 14,500 therms, per therm $ 0.1186 Next 35,000 therms, per therm $ 0.0639 Over 50,000 therms, per therm $ 0.0605
Washington, USA	CASCADE NAT GAS CORP	96 cities and towns in Washington and Oregon, Almost all of Washington (except north east)	262,000	Residential Service General Commercial Service Rate General Industrial Service Rate Large Volume General Service Rate Interruptible Service Rate Limited Interruptible Service Rate (Optional) Customer Owned Piping Construction, Operation, and Maintenance Compressed Natural Gas Service Gas Air Conditioning Residential Heating Equipment Distribution System Transportation Service		**RESIDENTIAL SERVICE** Basic Service Charge $4.00 per month All Gas Used per month 0.84307 per therm (includes WACOG)	**GENERAL COMMERCIAL SERVICE** Basic Service Charge $10.00 per month All Therms used $0.80999 per therm (includes WACOG)	**GENERAL INDUSTRIAL RATE** Basic Service Charge $24.00 per month First 500 therms/month $0.75635 per therm Next 3,500 therms/month $0.71814 per therm First 500 therms/month $0.71236 per therm (includes WACOG)
Wisconsin, USA	MADISON GAS ELEC CO	seven south-central and western Wiscor	144,000	Residential Distribution Service Residential Lifeline Distribution Service Small Commercial and Industrial Distribution Service Medium Commercial and Industrial Distribution Service Large Commercial and Industrial Distribution Service Interruptible Generation Distribution Service Seasonal Off-Peak Distribution Service Steam and Power Generation Gas Distribution Service Contracted Distribution Service Compressed Natural Gas Distribution Service Firm Gas Sales Service Interruptible Gas Sales Service Interruptible Large Boiler Gas Sales Service Large Annual Use Gas Sales Service Daily Balancing Service Hourly Operational Flow Order Rider (Experimental) Backup Sales Service Firm Gas Sales Service for Natural Gas Vehicles Purchased Gas Adjustment and Refund Provision Natural Gas Sales Priority Use Program Natural Gas Curtailment Plan Distribution Service for Natural Gas Vehicles		**Residential Distribution Service** Customer charge per day $0.4000 Distribution service per therm $0.2739	**Small Commercial and Industrial Distribution Service** Customer charge per day $0.6930 Distribution service per therm $0.1386	**Large Commercial and Industrial Distribution Service** Customer charge per day $20.0116 Distribution service per therm $0.0650