DISCUSSION PAPER ON GAZ MÉTRO'S COST OF SERVICE

TABLE OF CONTENTS

1 BACKGROUND

1.1 CHRONOLOGY OF EVENTS

During the 2011 rate case, the then-existing working group asked the Régie to authorize technical meetings to allow Gaz Métro to provide a quantitative demonstration of the cost of service allocation methodology.[1] In Decision D-2010-144, the Régie de l'énergie ("the Régie") authorized such working sessions and asked the working group to "examine the relationship between the results of the cost allocation study and the existing distribution rate design."[2] The Régie asked Gaz Métro Limited Partnership ("Gaz Métro") to file "a report on the discussions at those meetings and, if applicable, suggestions for possible improvements to the rate structure."[3]

Accordingly, a report on cost allocation, cost causation and Gaz Métro's vision of distribution rate design[4] was filed in the 2012 rate case. Among other things, it covered the objectives and guiding principles of cost allocation, provided a quantitative demonstration of cost allocation and suggested areas for further reflection and adjustment. In Decision D-2011-182, the Régie declared itself satisfied with the quantitative demonstration of the cost allocation methods and took note of the suggested areas for reflection. It asked Gaz Métro to follow up in the 2013 rate case and to make recommendations in the 2014 rate case.

The report on cost allocation and rate design filed in the 2012 rate case suggested improvements to distribution rates. In Decision D-2011-182, the Régie asked Gaz Métro to round out its rate design proposal by including more in-depth analyses of, among other things, cost classification, customer segmentation and cross-subsidization levels. Gaz Métro was encouraged to use the services of a rate design expert to prepare these analyses.[5]

[1] R-3720-2010, 2nd re-amended application, September 2, 2010, p. 6.
[2] D-2010-144, p. 26.
[3] D-2010-144, p. 26.
[4] R-3752-2011, 2012 rate case, Gaz Métro-13, Document 8 (*Rapport sur l'allocation des coûts, les liens entre les coûts et les tarifs ainsi que la vision tarifaire de Gaz Métro en distribution*).
[5] D-2011-182, p. 83.

In accordance with the Régie's request, Gaz Métro filed a progress report on the analyses of cost allocation and rate design in the 2013 rate case.[6] Gaz Métro also reported that it had retained the services of Dr. Edward Overcast of Black & Veatch to assist it in the process.

Following the filing of the progress report, the Régie ordered that the study of cost allocation and rate design be dealt with in a generic case, independent of the rate cases.[7]

The Régie believes that this procedural vehicle, i.e. a generic case, will allow for more flexible treatment of the matter, as the progress of the case will not be subject to the rate-setting calendar. It also believes that the technical aspects of cost allocation and rate design should be discussed at working sessions to enable the Régie's technical staff and intervenors to more closely follow the progress of the case dealing with Gaz Métro's rate design proposals and reflection.[8]

In Decision D-2013-170, the Régie again instructed that cost allocation issues be dealt with in a generic case and examined by a working group.

1.2 Expert's terms of reference

In accordance with the Régie's recommendation, Gaz Métro retained the services of Dr. Edward Overcast of Black & Veatch to assist it in its reflection on cost allocation and the rate structure. Dr. Overcast is an expert on public utility rate-setting who has extensive experience with gas distributors in Canada and the U.S.[9] In general terms, his mandate was to produce a critical report assessing cost of service allocation methods, customer segmentation and the existing rate structure. Three bidders responded to Gaz Métro's call for tenders. The quality of the proposal from Dr. Overcast of Black & Veatch set it apart.

The selected expert therefore reviewed Gaz Métro's cost allocation methodology, customer segmentation and rate structure, and then made recommendations on each of these points. While Dr. Overcast's proposed changes could theoretically be analyzed separately, they form an integrated whole. The changes he suggests to mains allocation lead naturally towards a specific customer segmentation and rate structure.

[6] R-3809-2013, Gaz Métro 15, document 1.
[7] D-2013-106, p. 125.
[8] D-2013-106, p. 125.
[9] See Dr. Overcast's résumé in Appendix.

Gaz Métro has carefully considered the outside consultant's recommendations. It will address each recommendation, assessing its merit, the practicalities of implementation, and the impact on the final outcome.

1.3 PROCEDURAL FRAMEWORK AND STRUCTURE OF DISCUSSION PAPER

Gaz Métro proposes to continue this process of reflection through an innovative regulatory process, similar to the one that will be instituted in accordance with Decision D-2013-091 on the design of the performance indicator aimed at optimizing supply tools.[10]

First, Gaz Métro is submitting the expert's report and this discussion paper, which reports the conclusions of Gaz Métro's preliminary analyses of the expert's recommendations on the specific issue of cost allocation and on possible improvements contemplated following Decision D-2010-144. This first discussion paper on cost allocation methodology surveys the issues that will be addressed in fuller analyses and with respect to which Gaz Métro intends to propose changes, if applicable, after the first series of working sessions. Gaz Métro will take into consideration the comments made at the working sessions and any written comments, which will be used to enrich its analysis. It will then set out its full analyses and proposed changes to the distribution cost allocation methodology in a progress report, which will follow the working sessions on this issue.

Dr. Overcast's analysis has led Gaz Métro to take a critical look at some practices that have been in place for many years, particularly with respect to allocation of mains costs. While the proposed changes to cost allocation were originally quite narrow, Gaz Métro has been brought to widen its analysis, which is now broader in scope than what was anticipated at the time of the 2012 and 2013 rate cases.

[10] D-2013-091, pp. 31 and 32.

The first section of this paper covers the overall objectives, legal context and general principles of cost allocation. This is followed by a discussion of issues related to the allocation of mains costs, in which Gaz Métro sets out the reasons that led it to consider changes to the method for estimating the access ("customer") and capacity ("demand") components of the cost of mains, and describes the alternatives it contemplates. Gaz Métro then deals with proposed changes to the allocation of costs other than mains. Finally, certain proposals submitted in the 2013 and 2014 rate cases are reviewed in this paper. These proposals may be enriched in the future by complementary analyses and working group discussions and comments.

Issues related to the rate structure of the distribution component will be dealt with at a later date in another discussion paper, which will take into account the proposed changes to cost allocation. Analyses and working sessions will specifically address issues involving the rate structure and load-balancing service.

2 GENERAL OBJECTIVES

In the 2012 rate case, Gaz Métro described the general objectives of its rate structure.[11]

First and foremost, rates must be designed to allow the utility to generate the distribution revenue requirement, including the authorized reasonable return.

In addition to this objective, Gaz Métro's rate design aims to:

3 be fair and reasonable for all user categories: the rates for different users of natural gas should be related to, without necessarily exactly reflecting, the cost of serving those users, the risks, and the competition. As a matter of fairness, cross-subsidization between rate classes must also be considered so as not to be unduly discriminatory towards any user category;

3 produce stable rates over time: customers are entitled to expect that required adjustments to rates will be introduced gradually;

3 be easy to understand, easy to administer and promote regulatory streamlining.

In the case at hand, these objectives will be pursued through a consideration of the following two areas:

3 cost allocation

3 review of the rate structure, including customer segmentation and tariff terms and conditions.

[11] R-3752-2011, Gaz Métro-13, Document 8, p. 35.

3 ALLOCATION OF DISTRIBUTION COSTS

3.1 LEGAL FRAMEWORK

Section 51 of the *Act respecting the Régie de l'énergie* ("the Act") provides that a distributor may not charge higher rates for delivery of natural gas than is necessary to enable it to cover its expenses and realize a reasonable return. The rate charged to customers must therefore be based directly on the overall costs of normal development and service delivery.

> *No electric power transmission tariff or natural gas transmission or delivery tariff may impose higher rates or more onerous conditions than are necessary to cover capital and operating costs, to maintain the stability of the electric power carrier or a natural gas distributor and the normal development of a transmission or distribution system or to provide a reasonable return on the rate base.*[12]

Section 49 of the Act adds to this general principle the importance of taking into account the cost of service, the different risk for different "classes of consumers" and, for the natural gas distributor specifically, competition and equity between "rate classes." Section 49 reads as follows:

> *When fixing or modifying rates for the transmission of electric power or for the transmission, delivery or storage of natural gas, the Régie shall, in particular,*
>
> […]
>
> *(6) consider the cost of service, the varying risks according to classes of consumers and, as concerns natural gas rates, the competition between the various forms of energy and the maintenance of equity between rate classes;*

The existing legislative framework therefore calls for rates that enable the utility to, first and foremost, meet the expenses deemed necessary for its stability and normal development of the system, including a return on its rate base, but also takes into account the risks associated with each user category, equity between customer classes, competitive considerations and the economic and social environment. The rates and conditions must also be fair and reasonable.[13]

[12] *Act respecting the Régie de l'énergie*, section 51.
[13] *Act respecting the Régie de l'énergie*, section 49.

In its 1985 Decision establishing cost allocation principles (Order G-429), the Régie de l'électricité et du gas adopted a guiding principle based on the provisions of the Act at the time. The Régie explained the adoption of cost causation as a guiding principle in these terms:

> *In the specific case of these rate classes, it is therefore possible to take into account the general principle set out in section 25 for the entire company. It holds that prices or rates must not exceed what is necessary to meet expenses and provide the Distributor with a reasonable return, insofar as the corporate expenses that are recovered through the rates can objectively be assigned to the various rate classes.*
>
> *The Régie believes that it must be guided by the application of this general principle to the specific case of each rate class in order to ensure equity between customers.*
>
> *This approach is consistent with regulatory precedents, which show a clear consensus to the effect that users should theoretically pay the costs associated with the service they receive and their share of the authorized return on equity.*
>
> *For these reasons, the Régie believes that it must maintain this principle as the main criterion in rate-setting, as opposed to other factors that some would use as the main criterion, such as the user's nature, the use to which the user puts the gas, or the level of competition from other fuels, none of which are referred to in the Régie's incorporating Act.*[14]

Section 49 of the Act allows latitude in setting distribution rates insofar as it allows for the risk associated with different user categories and competition for customer classes to be taken into account. While the causation principle remains essential in cost allocation and an important factor in establishing rate structures, it must not be the only criterion taken into account.

3.2 GUIDING PRINCIPLES

Economists Marcel Boyer, Michel Truchon and Michel Moreaux of the CIRANO research centre recently produced an exhaustive study of the various cost allocation[15] and infrastructure pricing[16] methods. In the analysis, the economists give an overview of cost allocation methodologies and their characteristics, which they classify into three major categories: .

[14] Order G-429, p. 57

[15] The authors use the terms "répartition des coûts" and "allocation des coûts" interchangeably to refer to cost allocation. These terms are to be distinguished from what Gaz Métro calls "répartition tarifaire," which refers to the distribution of rate increases across rate classes.

[16] Boyer, Moreaux, Truchon, *Partage des coûts et tarification des infrastructures*, Centre interuniversitaire de recherche en analyse des organisations, 2006.

3 Proportionate allocation

3 Allocation based on cooperative game theory (incremental cost)

3 Serial cost sharing.

The proportionate allocation methods, which result in "fully distributed costs," are the oldest of all the methods and are still widely used. The allocation method described in Order G-429, issued by the Régie de l'électricité et du gas, and the one currently applied by Gaz Métro, are both based on proportionate principles. In this approach, costs are divided proportionately among customer classes based on number of customers, volume, revenues or some combination of these factors.

Allocation based on cooperative game theory considers the problem of cost allocation as a cooperative game, in which players seek to form alliances in order to minimize their costs. These methodologies introduce the concept of incremental cost into cost allocation and rate design. Incremental cost pricing is not widely used in North America.

Serial cost sharing is more recent, having been developed in the last two decades. Under this type of allocation, all entities are assigned an equal share of the cost of the minimum-capacity infrastructure required to meet the needs of the customer group with the smallest needs. The customers that cannot be served with this minimum capacity are also allocated an equal share of the additional costs that must be incurred to increase capacity by the amount required to meet their greater demand.

In their study, economists Boyer, Truchon and Moreaux list what they consider to be the desirable characteristics of a cost allocation method, regardless of methodology.[17]

1. Equal treatment of equivalents: a cost-sharing rule should treat entities with comparable or identical demand in the same way.

2. The serial principle: an entity's contribution should not be affected by demand greater than its own from other entities. In other words, in projects with significant economies of scale, an entity with large needs may not want smaller entities to profit, at its expense, from the economies of scale that it is generating. The contributions demanded of small entities should not vary according to greater demand from other entities.

3. Treatment of negligible quantities: a positive share of cost should not be assigned to an entity with zero demand.

4. Uniformity: if costs should increase, the share of costs assigned to a customer class cannot decrease. It should be expected that entities will pay more when they increase their demand or when costs increase.

5. Limit on contributions: no entity should be assigned a share of costs greater than its standalone costs and each entity should pay at least its standalone costs.

6. Insensitivity to units of measure: the share of costs assigned to each entity should not depend on the units of measure in which demand is expressed.

7. Separability: if costs can be separated among entities, so too should cost allocation. In other words, the share of costs assigned to entities should match the costs for which they are directly responsible.

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[17] Boyer, Moreaux, Truchon, *Partage des coûts et tarification des infrastructures*, Centre interuniversitaire de recherche en analyse des organisations, 2006, pp. 88-99

Experts on the subject agree that it is difficult if not impossible to develop an allocation method that has all these characteristics. Nevertheless, it is important to bear them in mind when adopting a cost-sharing rule, particularly for the sharing of common costs, where direct allocation is impossible. It is important to be aware of the characteristics that are being given priority and those that are being sacrificed.

In an article published in the *Energy Studies Review,* economists Salant and Watkins give priority to two principles that they consider minimum requirements for common cost allocation:

1. Standalone cost test: the cost assigned to each customer should not exceed his standalone costs. Similarly, no group of customers should be required to pay more than its standalone costs.

2. Incremental cost test: no group of customers should subsidize another group. The costs borne by each group of users must be at least as large as the incremental cost of including that group on the system.

According to Salant and Watkins, the cost-sharing rule used must, at a minimum, satisfy these two criteria in order to be considered fair and equitable.

Salant and Watkins also identify other cost allocation principles which are desirable but of secondary importance.

1. Symmetry: customers who affect system costs in the same way should be allocated the same share of costs.

2. Decomposition principle: customers should not be required to contribute to portions of the system that they do not use. Only those who use a component should have to pay for it.

3. Monotinicity: as total costs increase, the costs allocated to a customer class should not decrease.

4. Consistency: the principles used in allocating costs between rate classes should also apply to allocating costs between rate levels.

The choice of allocation method will therefore depend on which characteristics are considered most important. Experts who have looked at the question of allocation principles agree that they cannot all be respected and hence some will have to be given priority.

> *Policy makers' choice of a formula for allocating costs will depend on which fairness criteria they judge to be the most important at the time.*[18]

Ideally, the order of priorities among the principles on which cost allocation will be based should be determined before knowing the resulting effect on the distribution of costs across rate classes and the impact on rates. Boyer, Moreaux and Truchon share this view.

> *Ideally, a method should be chosen on the basis of its characteristics before knowing what results it will yield. It is therefore important to decide on cost allocation methods based on the general characteristics they possess or do not possess.*[19]

This approach may appear difficult to apply in practice. Nevertheless, it is important to familiarize oneself with the desired principles and to bear them in mind during consideration of proposed changes.

Dr. Overcast, who guided Gaz Métro's reflection, made the following comment about the merits of adopting guiding principles for cost allocation. (The following quote is from the stenographer's notes in the recent case on the cost of service methodology of Enbridge Gas New Brunswick Inc.).

> *I mean you are adopting principles here and if you are willing to stick to those principles down the road when the final cost of service study gets done there is not going to be a lot of argument over the results*.[20]

In our assessment of the various options for allocation of common costs, it will be appropriate to take into account which principles are being respected and which are not. It is important to understand which principles are being given priority and which are being sacrificed or assigned less importance in choosing a method. In Decision G-429, the Régie identified certain allocation principles on the basis of which it assessed the various cost allocation methods for the capacity component of mains. Close attention will be paid to the underlying principles in our discussion of contemplated changes.

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[18] Salant, Watkins, "Cost-allocation principles for pipeline capacity and usage," *Energy Studies Review* 8(2), 1996, p. 94.

[19] Boyer, Moreaux, Truchon, *Partage des coûts et tarification des infrastructures*, Centre interuniversitaire de recherche en analyse des organisations, 2006, p. 88.

[20] EGNB-2010-002, transcript, hearing of September 20, 2010, p. 256.

3.3 COST ALLOCATION AT GAZ MÉTRO

The methodology for the study of cost allocation at Gaz Métro is based on the cost causation principle, whereby "each rate class must provide the company with neither more nor less than the annual revenue required to meet the annual expenses it generates and to provide a reasonable return on the capital expenditures made to serve it."[21] This principle was approved by the Régie in the generic case on cost allocation principles (Decision G-429).

The cost allocation process therefore demands a sound understanding of cost causation. The preferred approach consists in assigning costs to the customers who caused them, when possible. Sometimes, the available information does not allow for direct assignment or the nature of the costs makes direct assignment impossible. When direct assignment of costs is not possible, allocation factors must be used and it is the calculation of these factors that can be controversial, particularly in the case of the allocation of common costs, such as cost of mains.

The main purpose of allocation is to share test year[22] costs between services and between user categories as fairly and reasonably as possible, while respecting cost causation, which is the guiding principle for the process. The final result will:

3 make it possible to determine the cost of serving each user category and the unit cost for each rate class and rate level;

3 support rate design. Gaz Métro's rate proposals are based on, among other things, its cost structure; and

[21] G-429, p. 61
[22] The test year is the year of the last budget approved by the Régie

- make it possible to assess the revenue / cost ratio per rate class and level in order to obtain a measure of cross-subsidization. The level of cross-subsidization is measured by the cost of service allocation study filed with the Régie de l'énergie in Gaz Métro's rate case.

The cost allocation method was described in detail in the 2012 rate case.[23] In Decision D-2011-182, the Régie declared itself satisfied with the demonstration of allocation methods.

The major stages of the cost allocation process are:

- Functionalization
- Classification
- Allocation.

Cost **functionalization** assigns all expenses to one of the five services provided by Gaz Métro: supply, compression, transmission, load balancing and distribution. This process is carried out by Gaz Métro's budget department. The functionalization methods are approved by the Régie. After completion of this process, the total cost to be recovered for each of the services is known and it is on this basis that the rates for each service are set. In particular, the rates for the distribution service are set so as to recover the total cost assigned to distribution.

Secondly, **classification** of accounts consists in organizing accounts by cost causation. Where direct assignment is possible, no allocation factor is required since the costs are assigned to the corresponding rate class. This is the case for service lines and meters, for example. When direct assignment is not possible, an allocation factor is determined. The classification stage therefore consists in determining cost causation and identifying an appropriate cost allocation factor for each account. Costs may be assigned either:

1. directly to customers;

[23] R-3752-2011, Gaz Métro-13, Document 8.

2. according to the relative proportions of the various customer classes, based on their peak consumption (capacity, demand, CU);

3. according to the relative proportions of the various customer classes, based on number of customers;

4. according to the relative proportions of the various customer classes, based on usage (volume); and

5. according to the relative proportions of the various customer classes, based on revenue generated.

Lastly, the allocation factors are calculated using the appropriate data or updated and then applied to the various budgets in order to determine the share of costs in each account to be allocated to each rate class. In some cases, the allocation takes regional differences into account. This is the **allocation** stage. The allocation factors are classified as follows:

1. Basic factors: these factors are determined either on the basis of the relative number of customers per rate class, relative demand, volume or revenues assignable proportionately to the various rate classes.

2. Mixed or special factors: these factors consist in a combination of two or three basic factors.

3. Derivative factors: these factors are determined on the basis of the distribution of a set of costs.

A table showing the list of distribution costs and the corresponding allocation factors was filed in the 2014 rate case in the exhibit on cost allocation.[24]

[24] R-3837-2013, B-0164, Gaz Métro-14, Document 2, pp. 6-9.

4 Summary of Dr. Overcast's observations on cost allocation

To support its reflection on the cost allocation process, Gaz Métro retained the services of Dr. Edward Overcast of Black & Veatch, who reviewed Gaz Métro's cost allocation method and rate structure, and made recommendations. Dr. Overcast's résumé is presented in Appendix 1. The method he recommends is an integrated whole that links cost allocation principles and customer segmentation to produce a logical rate structure. It should be noted that Dr. Overcast has extensive experience working with regulated utilities and has developed a model that has been used by numerous regulatory agencies across North America. The recommendations made by Dr. Overcast (Ph.D. in Economics) are thus known and recognized in the regulated industries community.

Gaz Métro is therefore paying close attention to its consultant's recommendations but will not embrace them without reflection and thorough analysis.

Dr. Overcast begins by looking at the cost allocation method and suggests some fairly fundamental changes, primarily to the method of allocating mains. According to Dr. Overcast, the access ("customer") component of the cost of mains, which is currently estimated using the zero intercept method, should be estimated using an alternative approach based on the cost of a minimum system. Dr. Overcast also suggests that the capacity ("demand") component of the cost of mains be assigned using an allocation factor not based on volume consumed, as is the case now. He argues that there is no causal relationship between volume used and system costs, and therefore the current method, which is based on capacity attributed and used, is not appropriate from either a theoretical or an empirical point of view.

> *As will be demonstrated below, volumetric use cannot be a cause for investment in capacity from either a theoretical or empirical basis.*[25]

Dr. Overcast's recommendations will be analysed with a view to determining their implications and their effect on rates.

[25] Black & Veatch, *Review of Gaz Metro's cost of service and rate design*, p. 8.

Dr. Overcast starts from the initial observation that the demand of a large portion of customers can be served using a minimum system composed entirely of small-diameter mains, namely 2-inch diameter plastic piping. The cost of serving this first customer class, which includes all residential customers and some low-volume commercial customers, is therefore the same, regardless of the volume withdrawn by these customers. The average cost of serving these customers is the same because the plant required to meet their demand is the same.

> *[T]hat all customers in a class are able to be served by the minimum size of mains installed leads to the conclusion that the average cost of mains to provide delivery service to residential and small service general 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*.[26]

Dr. Overcast therefore recommends that customer segmentation be based primarily on this characteristic and that all customers whose demand can be served via a minimum system of 2-inch diameter mains be included in the first rate class. There is therefore a direct linkage between allocation of the cost of mains and customer segmentation for rate-setting purposes. Dr. Overcast recommends the creation of three segments within the current D_1 rate class, which he tentatively defines as follows:

> *Small General Service rate D_0 for customers with annual volumes of approximately 0 to 36,500 m³; Mid General service D_1 for customers with annual volumes greater than 36,500 to approximately 365,000 m³; and Large General service D_2 for customers with annual consumption larger than 365,000 m³.*[27]

As the minimum system composed of 2-inch diameter mains has the capacity to meet the total demand of the first customer class, i.e. customers whose annual volume does not exceed 36,500 m³, allocation of mains costs to this customer category need not include a capacity component. Dr. Overcast recommends correcting in this way the bias produced by using the minimum system method to allocate mains costs.

[26] Black & Veatch, *Review of Gaz Metro's cost of service and rate design*, p. 8.
[27] Black & Veatch, *Review of Gaz Metro's cost of service and rate design*, p. 29.

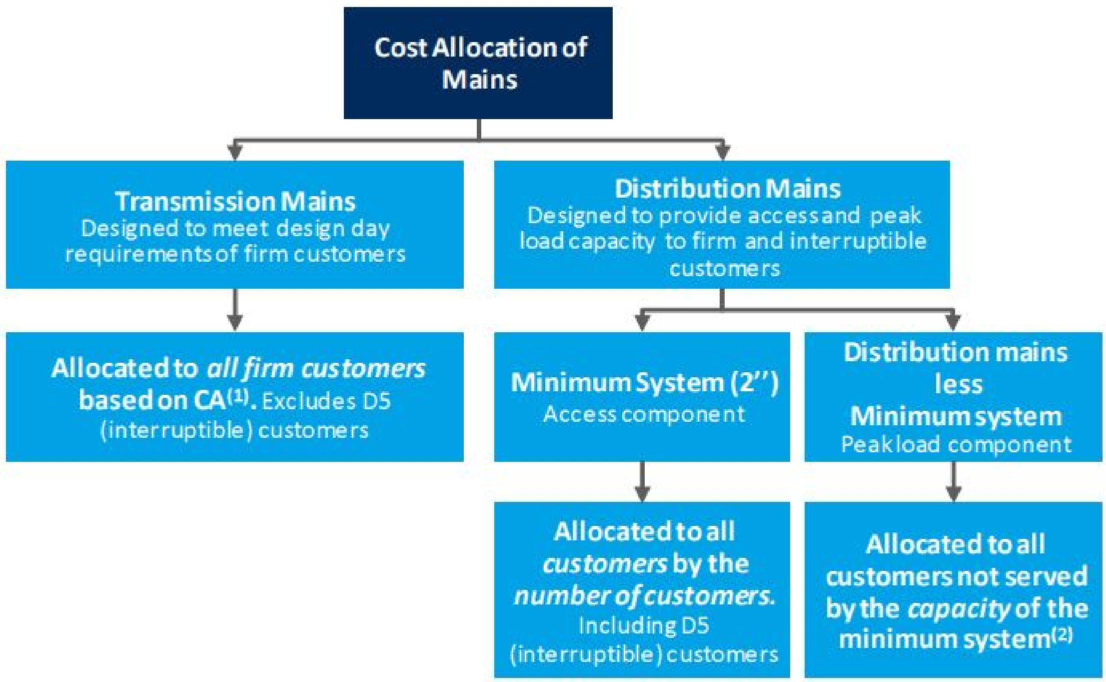
> *When allocating the minimum system component to the smallest customers also serves the class design day demand, there is no need to allocate any additional distribution capacity costs to the smallest customer class based on demand. Thus the demand cost equal to the main cost not included in the customer component is allocated to the remaining classes based on design day demand.*[28]

Dr. Overcast emphasizes the fact that economies of scale are such that the average cost of serving larger-volume customers is much lower than the cost of serving the lower-volume customers who would be in the first rate class. This is because doubling the pipe diameter (installing 4-inch instead of 2-inch diameter mains) quintuples delivery capacity but has only a marginal impact on system cost.

> *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*.[29]

Therefore, the average cost for large-volume customers whose demand cannot be satisfied with a minimum system of 2-inch diameter pipes will be lower than the average cost for customers in the first rate class. This fact should have repercussions for the rate structure, in Dr. Overcast's view. The following diagram from his report illustrates his recommendations concerning the allocation of mains costs.

[28] Black & Veatch, *Review of Gaz Metro's cost of service and rate design*, p. 8.
[29] Black & Veatch, *Review of Gaz Metro's cost of service and rate design*, p. 10.



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)

Source : Black&Veatch, *Review of Gaz Metro's cost of service and rate design*, page 19

The consultant therefore suggests that the minimum system method be used rather than the zero intercept method to estimate the access component of the cost of mains and that the capacity component be allocated only to high-volume rate classes that cannot be served by a minimum system of 2-inch diameter mains. He also proposes that the capacity component be allocated not on the basis of CAU, which is determined in part by the volumes used, but only on the basis of maximum daily demand. It should be noted that Dr. Overcast suggests that the non-coincident peak for interruptible service customers be used to take into account the capacity attributed to these customers.

> *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).*[30]

These recommendations on the allocation of mains costs and the naturally resulting customer segmentation lead to specific rates for each of the three major customer segments in the current D_1 rate class. Dr. Overcast's rate proposals will be discussed in the second phase of the reflection process.

Dr. Overcast considered other aspects of the cost allocation and rate-setting process and produced suggestions that are interesting but of lesser importance. Gaz Métro has assessed the primary and secondary recommendations made by its consultant Dr. Overcast and will produce analyses in order to be able to take a position and decide whether or not to submit proposals for changes beyond the most important one concerning mains.

[30] Black & Veatch, *Review of Gaz Metro's cost of service and rate design*, p. 17.

5 MAINS ALLOCATION

5.1 CHARACTERISTICS OF MAINS SYSTEM

The mains included in the rate base can be divided into three major categories, according to their function and the pressure at which they carry gas.

1. Distribution mains carry natural gas from the gas pressure regulator stations to the customer service lines. The pressure in the distribution mains is between 0 and 700 kPa.

2. Supply mains* are used both to deliver natural gas to large-volume customers and to carry natural gas from the city gate to the gas pressure regulator stations. Supply mains have a pressure between 1,000 and 2,900 kPa. Supply mains are of varying diameters and are not necessarily larger than the distribution mains that carry natural gas from the gas pressure regulator stations to customer service lines.

3. Transmission mains are generally larger in diameter than the other two categories and carry gas to the city gate at a pressure between 4,400 and 9,928 kPa.[31]

According to data from Gaz Métro's Engineering Department, distribution mains made up 74% of its system in 2012/2013, while supply mains and transmission mains accounted for 18.4% and 7.6% respectively of the system's piping, in terms of linear metres. The mains are made of plastic (59.4% of total linear metres), steel (40.5% of total linear metres) or aluminum (0.1%). They vary in diameter but most are either 60.3 mm (25%), 114.3 mm (30%) or 168.3 mm (18%) in diameter. The tables on the following pages show the main characteristics of the existing system.

It is interesting to note that most distribution mains (80%) are made of plastic. They are of all sizes. Twenty percent (20%) of distribution mains are made of steel. Almost all supply mains (99.8%) are made of steel. They come in all sizes.

* Gaz Métro uses the term "supply main" to describe its medium-pressure distribution mains, which are used primarily to deliver gas to the gas pressure regulator stations.

[31] There are no mains carrying gas at pressure levels between 700 and 1000 kPa or between 2900 and 4400 kPa.

Main features of system – 2012/2013

		Diameter (mm)	Length (metres)	Proportion	Proportion
Distribution mains					
	Steel	26.7	5,031	0.1%	0.0%
		33.4	28,106	0.4%	0.3%
		42.2	26,326	0.3%	0.3%
		48.3	97,293	1.3%	0.9%
		60.3	317,847	4.1%	3.1%
		88.9	201,668	2.6%	1.9%
		114.3	348,989	4.5%	3.4%
		168.3	310,381	4.0%	3.0%
		219.1	129,675	1.7%	1.2%
		273.1	6,865	0.1%	0.1%
		323.9	28,777	0.4%	0.3%
		406.4	11,270	0.1%	0.1%
	Total Steel		**1,512,228**	**19.7%**	**14.6%**
	Plastic	26.7	362	0.0%	0.0%
		42.2	281,133	3.7%	2.7%
		60.3	2,237,170	29.1%	21.6%
		88.9	196,174	2.6%	1.9%
		114.3	2,431,771	31.7%	23.4%
		168.3	953,548	12.4%	9.2%
		219.1	64,475	0.8%	0.6%
	Total Plastic		**6,164,632**	**80.3%**	**59.4%**
Total distribution			**7,676,861**	**100.0%**	**74.0%**

Source: Engineering Department, Gaz Métro, 2012-2013 file

		Diameter (mm)	Length (metres)	Proportion	Proportion
Supply mains					
	Steel	21.3	11	0.0%	0.0%
		26.7	61	0.0%	0.0%
		33.4	4	0.0%	0.0%
		42.2	100	0.0%	0.0%
		60.3	7,003	0.4%	0.1%
		88.9	8,436	0.4%	0.1%
		114.3	284,933	14.9%	2.7%
		168.3	529,491	27.7%	5.1%
		219.1	313,800	16.4%	3.0%
		273.1	278,290	14.6%	2.7%
		323.9	151,122	7.9%	1.5%
		406.4	244,717	12.8%	2.4%
		508.0	51,180	2.7%	0.5%
		610.0	18,280	1.0%	0.2%
		762.0	8,104	0.4%	0.1%
	Total Steel		**1,895,533**	**99.3%**	**18.3%**
	Aluminium	48.3	2,201	0.1%	0.0%
		60.3	167	0.0%	0.0%
		88.9	11,122	0.6%	0.1%
	Total Aluminium		**13,489**	**0.7%**	**0.1%**
Total supply			**1,909,022**	**100.0%**	**18.4%**

Source: Engineering Department, Gaz Métro, 2012-2013 file

		Diameter (mm)	Length (metres)	Proportion	Proportion
Transmission mains					
	Steel	60.3	1,066	0.1%	0.0%
		114.3	23,485	3.0%	0.2%
		168.3	61,559	7.8%	0.6%
		219.1	158,135	20.0%	1.5%
		273.1	83,459	10.6%	0.8%
		323.9	65,084	8.2%	0.6%
		406.4	382,757	48.5%	3.7%
		508.0	13,723	1.7%	0.1%
Total transmission			**789,269**	**100.0%**	**7.6%**
Grand total			**10,375,151**		**100.0%**

Source: Engineering Department, Gaz Métro, 2012-2013 file

Mains by diameter

Diameter *(mm)*	Sum of lengths *(metres)*	Percentage
21.3	11.2	0.0%
26.7	5,453.69	0.1%
33.4	28,109.99	0.3%
42.2	307,558.28	3.0%
48.3	99,494.16	1.0%
60.3	2,563,253.16	24.7%
88.9	417,400.94	4.0%
114.3	3,089,177.75	29.8%
168.3	1,854,979.17	17.9%
219.1	666,084.95	6.4%
273.1	368,614.04	3.6%
323.9	244,983.31	2.4%
406.4	638,744.32	6.2%
508	64,902.44	0.6%
610	18,279.56	0.2%
762	8,104.32	0.1%
Grand total	**10,375,151.3**	**100.0%**

Source: Engineering Department, Gaz Métro, 2012-2013 file

Mains by pressure

Type of main	Pressure (kPa)	Sum of lengths *(metres)*	Percentage
Distribution	Less than 1,000 kPa	7,676,860.7	74.0%
Supply	1,000 to 2,400 kPa	1,575,895.8	15.2%
	2,400 kPa to 4,400 kPa	333,126.21	3.2%
Transmission	More than 4,400 kPa	789,268.57	7.6%
Grand total		**10,375,151.3**	**100.0%**

Source: Engineering Department, Gaz Métro, 2012-2013 file

Mains by material

Material	Type of main	Length *(metres)*	Proportion
Steel	Distribution	1,512,228	14.6%
	Supply	1,895,533	18.3%
	Transmission	789,269	7.6%
Total steel		**4,197,029**	**40.5%**
Aluminium	Supply	13,489	0.1%
Total aluminium		**13,489**	**0.1%**
Plastic	Distribution	6,164,632	59.4%
Total plastic		**6,164,632**	**59.4%**
Grand total		**10 375 151**	**100.0%**

Source: Engineering Department, Gaz Métro, 2012-2013 file

5.2 PRINCIPLES OF MAINS ALLOCATION

Distribution costs related to mains, i.e. operating expenses for mains, amortization of mains and the return on the unamortized value of the mains, cannot be directly assigned since the specific customers who gave rise to these expenses cannot be isolated. An allocation factor that reflects cost causation as accurately as possible must therefore be used for allocation of annual mains-related expenses. The CONDPRIN allocation factor has been developed for this purpose.[32]

The current allocation method is based on the premise that the distribution system performs two distinct functions:

3 Providing access to the gas system for the customers who are connected to it. A portion of distribution system costs derive from the fact that all customers are given access to the natural gas system, regardless of the volume they use. This component of the allocation factor is called the “customer” or “access” component and is divided among customer classes based on their relative numbers.

[32] The CONDPRIN allocation factor is described in detail in Gaz Métro-13, Document 8, R-3752-2011, Appendix A.

3 Delivering the gas volumes demanded by customers over the course of the year. A portion of distribution system costs derives from the natural gas capacity to which customers have access. This component of distribution system costs is referred to as the capacity component and is divided among customer classes on the basis of their maximum daily demand and the volume they use.

An important step in the process of allocating distribution system costs therefore consists in determining the relative weighting of the access and capacity components. The method accepted and used by Gaz Métro begins by estimating the costs related to the access component and then deduces the capacity component by subtracting the estimated access component from total distribution system costs.

Two methods for determining costs related to the access function are widely accepted.

1. The "zero intercept method" uses linear regression to estimate the cost of installing a distribution system with no capacity to deliver gas, i.e. a system in which the diameter of the mains is zero millimetres. It establishes the intercept value of a regression line that plots the relationship between two variables: the cost of mains and pipe diameter.

2. The "minimum system method"[33] consists in estimating the cost of a minimum system, i.e. the smallest possible system, on the basis of accounting data. The characteristics of this hypothetical minimum system are based either on current practice or on the system's history. Dr. Overcast suggests that the minimum system be defined as consisting of 2-inch diameter plastic piping.

In Decision G-429 of 1985, the Régie found that the minimum system method entailed a double cost allocation for customers whose volume could be delivered over a minimum-diameter pipe.

[33] Footnote not relevant to English version.

> *In this method, all customers are initially assigned an identical share of costs for a two-inch system and then a share of the cost of the "delivery" function, proportionate to their respective volumes. As this two-inch system has a specific delivery capacity, the cost of which is included in the "customer component," determined according to the method described above, customers whose volumes can be delivered over a two-inch pipe are allocated costs twice.*[34]

The Régie therefore rejected the minimum system method since it does not fully distinguish between costs related to the access component and those related to the capacity component. Under this approach, costs related to the access component include a portion of capacity-related costs. This shortcoming, which is recognized by all authorities on the subject, can however be compensated for as some experts have suggested. Dr. Overcast also proposes a way of offsetting this bias in his recommendations to Gaz Métro.

The main criticism of the zero intercept approach, which was adopted in 1985 and is still used by Gaz Métro today, is that, while it is conceptually rigorous, its application entails difficulties that make the results statistically unreliable. Inconsistent results may be produced by lack of adequate data, the use of accounting data that is not properly adapted for statistical extrapolation, or use of a regression model that cannot support statistically robust results.

Gaz Métro's experience shows that application of the zero intercept method can present difficulties that render the results difficult to interpret. For example, in 1997 the Régie approved changes to the zero intercept method to correct a bias that led to overestimating the cost of a zero diameter system.

> *The first improvement relates to the basic calculation of the piping required to connect customers. This cost is currently overestimated because it is higher than the cost of a 2-inch diameter main, which would be sufficient not only to connect customers but also to meet the annual and peak consumption needs of a good number of the smaller customers. The current method therefore overestimates costs for the smallest customers, essentially residential customers. The proposed method corrects this flaw.*[35]

[34] Order G-429, p. 75.
[35] R-3323-94, GMi-1, Document 1.1, p. 9.

In view of uneven growth of the residential, commercial and industrial customer base in different regions within Gaz Métro's service area, it was proposed that the cost of zero-diameter pipes be calculated by region.

In Decision D-97-95, the Régie approved the request to allocate mains by region and to use pipe diameter rather than diameter squared as the explanatory variable in the linear regressions used for the purpose of calculating the cost of a zero-diameter distribution system.[36]

As Dr. Overcast recommends cost of mains allocation based on the minimum system method, a critical look at the application of the zero intercept method is called for.

5.3 Estimating the access component of the cost of mains

The model currently used to estimate the value of a zero-diameter system is the following:

$$\textit{Average linear cost of mains} = \textit{Constant} + \beta \textit{ pipe diameter}$$

A linear regression is performed to determine the value of the constant for the cost of a zero-diameter main. This cost is then multiplied by the number of linear metres of mains to obtain the total cost, in constant dollars, of a system composed of zero-diameter pipes, i.e. with no capacity to deliver gas. This cost represents the access component of the cost of a system of pipes.

In accordance with Order G-429, the access component is divided among the rate classes on the basis of number of customers. The capacity component is allocated according to a formula that takes into account the volume used and the capacity attributed (capacity attributed and used).

Despite adjustments made in 1997, the experience of the past 10 years shows that difficulties still persist in the application of the zero intercept method. These difficulties are serious enough to lead us to question the reliability of the results and to contemplate either adjustments to the method or the adoption of an alternative approach such as the one suggested by Dr. Overcast.

[36] D-97-47, p. 23.

Based on an analysis of the results yielded by this approach over the past five years, Gaz Métro has identified three concerns about the zero intercept method that it is applying.

5.3.1 Quality of available data and small number of data points

The intercept value is estimated on the basis of accounting data which is not always appropriate for calculating the unit cost of mains, since some entries made for accounting purposes can bias our model's results. For example, some accounting entries indicate a negative capitalized value or zero lengths of mains. These entries must be purged from the database on which the linear regression is performed; otherwise, the results may be difficult to interpret.

To address this deficiency in the data, the average linear cost of mains is obtained by calculating the ratio of the sum of the capitalized cost of all mains to the total linear metres of mains.

$$\text{Average cost of mains: } \frac{\text{Value of all mains of diameter i}}{\text{Sum of lengths of all mains of diameter i}}$$

Taking the sum of values mitigates the impact of some of the inconsistencies in the database. In this case, the regression model is not applied to the cost per linear metre of each main but to a smaller number of data points, as the number of points for the regression equals the number of different diameters in the system of mains. As the number of available data points and the number of degrees of freedom are small, we cannot always obtain statistically significant results.[37]

[37] The number of points used for a regression determines the degrees of freedom, which are a factor in the significance and t-student tests.

The following table shows the number of data points for the regression analysis for each of the six regions in recent years. As can be seen, the number of data points and hence the degrees of freedom available for estimating the model are small.

Regression data for estimating 0 intercept

Years	Number of data points	Degrees of freedom
2006-2007		
Montréal	12	11
Abitibi	9	8
Mauricie	9	8
Estrie	8	7
Québec City	9	8
Saguenay	7	6
2009-2010		
Montréal	12	11
Abitibi	9	8
Mauricie	9	8
Estrie	8	7
Québec City	9	8
Saguenay	7	6
2012-2013		
Montréal	12	11
Abitibi	9	8
Mauricie	10	9
Estrie	8	7
Québec City	9	8
Saguenay	7	6

Source: Rates Department, Gaz Métro

5.3.2 Statistical validity of results

Two statistical tests are commonly used to assess a model's statistical validity.

3 R^2 represents the proportion of variances in the dependent variable that are explained by the model. The closer R^2 is to 1, the more powerful the model is. For example, an R^2 of .88 means that 88% of the variations in unit cost are explained by the diameter variable. The farther R^2 is from 100%, the less complete the model is.

R^2 is a simple and attractive indicator but it has limitations. It cannot show whether the model is statistically relevant for explaining the values of the dependent variable. We also need to perform a significance test to determine whether the relationship shown by the regression is not just an artifact.

3 The t-student statistical test is used to test the hypothesis that the value of the regression coefficients is not significantly different from 0. The value the t-student must reach in order to invalidate the null hypothesis depends on the number of data points and the desired confidence interval (generally 90% to 99%). In practice, the critical value usually oscillates around 2. However, the results obtained over the years do not always make it possible to reject the hypothesis that the intercept is not equal to 0. The P value is often a useful complement for interpreting the t-student test. It expresses the probability that the coefficient is equal to 0 in view of the value of t. For example, when P = 0.37, there is a 37% probability that the actual value of the coefficient in question is 0. When the value is greater than 0.05, the null hypothesis cannot be rejected at 95% confidence.

The following table shows the numbers produced by the zero intercept method in past rate cases. As can be seen, the t-student value does not allow us to reject the null hypothesis in a number of cases (underlined P value).

Estimated intercept value

Year	Intercept	t- student	P	R^2
2006-2007				
Montréal	42.35	2.72	0.0214	0.7207
Abitibi	19.76	2.31	<u>0.0545</u>	0.9547
Mauricie	10.39	1.13	<u>0.2964</u>	0.9896
Estrie	47.36	2.25	<u>0.0655</u>	0.8334
Québec City	75.98	2.59	0.0357	0.8029
Saguenay	52.59	3.38	0.0196	0.9039
2009-2010				
Montréal	40.88	2.53	0.0301	0.7080
Abitibi	20.00	2.32	<u>0.0536</u>	0.9541
Mauricie	11.25	1.16	<u>0.2825</u>	0.9885
Estrie	47.20	2.24	<u>0.0662</u>	0.8339
Québec City	75.89	2.59	0.0361	0.8026
Saguenay	52.91	3.39	0.0195	0.9028
2012-2013				
Montréal	40.43	2.39	0.0376	0.6826
Abitibi	20.20	2.61	0.0350	0.9632
Mauricie	11.54	0.34	<u>0.7449</u>	0.8391
Estrie	49.24	2.3	<u>0.0613</u>	0.8250
Québec City	75.24	2.57	0.0370	0.8042
Saguenay	51.54	3.30	0.0215	0.9044

Source: Rates Department, Gaz Métro

Our results therefore indicate that the intercept, which is the value used for calculating the cost of a hypothetical zero-diameter network, is not always significant. In particular, the results for Mauricie are not clearly statistically significant. In general, the t-student is not significantly higher than the reference value[38] for all regions except Saguenay. These data points therefore indicate that, based on statistical tests, the intercept estimate is not very meaningful.

[38] The t-student table gives a reference value of 2.3 with a 95% confidence interval and a degree of freedom between 8 and 10.

These results are due to, among other things, the small number of data points on which the regression was performed.

In Enbridge New Brunswick's 2012 rate case, Dr. Overcast was consulted as an expert and gave his interpretation of the statistical validity problems associated with the zero intercept method.

> *Next, the results are insignificant because in the steel regression the t-statistic is not significant which means that the hypothesis that the parameter is significantly different than zero cannot be rejected. For the linear models for steel and plastic, the t-statistic for the intercept term is not significant in either regression. As noted above this means that the intercept, which is the variable of interest in the zero intercept method, is virtually meaningless. As I will explain below, these regressions are not useful in any context based on the proposition that customers do not cause costs. Thus we have only one significant intercept term in any of the unweighted models and that is for the plastic pipe with the independent variable defined as the square of the diameter. In that model, the intercept term was appropriately the same as the cost of the 1,25 inch plastic pipe*.[39]

We therefore find that, although the zero intercept approach is theoretically correct, its application involves difficulties in terms of the statistical validity of the results.

5.3.3 Significant regional variations

The following table shows the proportion of the cost of mains attributable to the access function, based on application of the zero intercept method in past rate cases. We note significant variances between different regions. Given our conclusions concerning the statistical validity of the intercept value, we need to ascertain that differential treatment of the regions is theoretically correct and error-free in its application.

[39] Decision in the matter of an application by Enbridge Gas New Brunswick Limited Partnership regarding the approval or fixing of rates and tariffs pursuant to section 52.2 of the Gas Distribution Act, 1999, Exhibit EGNB6,02, p. 3.

Proportion of cost of mains assigned to the access function under the zero intercept method

Years	Intercept value (zero diameter unit cost in $)	0 intercept system cost / Total cost of distribution mains (%)
2006-2007		
Montréal	42.35	45.9
Abitibi	19.76	26.9
Mauricie	10.39	12
Estrie	47.36	47.0
Québec City	75.98	52.8
Saguenay	52.59	42.5
2009-2010		
Montréal	40.88	44.0
Abitibi	20.00	27
Mauricie	11.25	12.7
Estrie	47.20	46.8
Québec City	75.89	52.7
Saguenay	52.91	42.7
2012-2013		
Montréal	40.43	44.7
Abitibi	20.20	26.7
Mauricie	11.54	13
Estrie	49.24	48.2
Québec City	75.24	52.4
Saguenay	51.54	41.9

Source: Rates Department, Gaz Métro

We observe that the low proportion assigned to the access component in the Mauricie region derives directly from the low intercept value for the region. It should be noted that our statistical test does not allow us to accept this intercept as a valid estimate of the cost of a system with zero-diameter pipes in Mauricie. The use of the zero intercept method therefore leads us to treat regions differently when there may not be any real justification for doing so.

In light of these observations and Dr. Overcast's recommendations concerning the minimum system method, Gaz Métro is not convinced of the appropriateness of maintaining the zero intercept approach it has been using since 1985. Analysis of our results reveals flaws that would justify switching to an alternative method or correcting the current method.

5.4 POSSIBLE ALTERNATIVES TO THE CURRENT ZERO INTERCEPT METHOD

5.4.1 Minimum system method

Switching from the zero intercept method to the minimum system method is one of Dr. Overcast's main recommendations. This approach has an impact on the proposed customer segmentation and on the rates for the various groups. Dr. Overcast distinguishes between customers whose demand and peaks can be served by a minimum system and higher-volume customers. His recommended customer segmentation and rates are based on this distinction.

Under this approach, the cost of a hypothetical minimum system is not estimated by linear regression but rather on the basis of historical cost obtained from accounting data or current costs. The method is based on the estimated cost of a hypothetical network composed entirely of mains of the smallest size (most often 60 mm or 2 inches in diameter). The difference between the cost of this hypothetical system and the cost of the actual system is then allocated to the capacity component.

Critics of this approach agree that it has the following weaknesses:

3 As the estimated cost is for a system with a certain delivery capacity, the calculated access component actually includes a portion of the capacity component. To correct for this shortcoming, it must therefore be determined whether a capacity component must be assigned to all customers and, if not, to which customer classes the capacity component should be allocated. Dr. Overcast of Black & Veatch suggests an approach for addressing the weakness of a minimum system based on 2-inch mains.

3 The minimum system must be defined. Dr. Overcast recommends that a system of 2-inch plastic mains be used as the minimum system. Some regulators have instead opted for the smallest possible system of pipes.

A reference manual on the issue of cost allocation produced by the National Association of Regulatory Commissioners describes the difficulties of an approach based on a minimum system with 2-inch diameter mains as follows.

> *The results of the minimum-size method can be influenced by several factors. The analyst must determine the minimum size for each piece of equipment: "Should the minimum size be based upon the minimum size equipment currently installed, historically installed, or the minimum size necessary to meet safety requirements?" The manner which the minimum size equipment is selected will directly affect the percentage of costs that are classified as demand and customer costs.*
>
> *Cost analysts disagree on how much of the demand costs should be allocated to customers when minimum-size distribution method is used to classify distribution plant. When using this distribution method, the analyst must be aware that the minimum-size distribution equipment has a certain load-carrying capability, which can be viewed as demand-related cost.*
>
> *When allocating distribution costs determined by the minimum-size method, some cost analysts will argue that some customer classes can receive a disproportionate share of demand costs. Their rationale is that customers are allocated a share of distribution costs classified as demand-related. Then those customers receive a second layer of demand costs that have been mislabelled customer costs because the minimum-size method was used to classify those costs*.[40]

Dr. Overcast recommends that the minimum system be defined as a system composed of 2-inch plastic piping because that is the basic system that can serve all the needs of the first customer class. The cost of this minimum system includes both an access component and a capacity component. As this system has enough capacity to serve the needs of the first rate class, no allocation of the amount by which the total cost of the system exceeds the cost of the minimum system needs to be made for this first customer group. Thus, application of the minimum system method cannot result in double allocation of the capacity component for small-volume customers. The amount by which the cost of the system exceeds the cost of the minimum system is allocated only to customers whose needs cannot be served by the minimum system, which has insufficient capacity.

[40] *Electric utility cost allocation manual*, National Association of Regulatory Commissioners, January 1992, p. 90.

5.4.2 Maintaining the zero intercept method with adjustments

Despite its weaknesses in terms of statistical validity, the zero intercept method could be kept, as it is recognized as theoretically correct.

Improvements could be made to strengthen the method's results. For example, the regression could be performed on all the data for the entire service area instead of by region.

However, if the zero intercept approach is maintained, the rates model recommended by Dr. Overcast cannot be applied.

In view of Dr. Overcast's proposal and the observed weaknesses of the zero intercept method, particularly the reliability of the statistical results, Gaz Métro contemplates adopting an alternative approach and in particular considering a minimum system approach based on 2-inch plastic mains. This change would mean reformulating the CONDPRIN allocation factor.

5.5 ESTIMATING THE CAPACITY COMPONENT

The capacity component of the cost of mains is estimated using one of the following three approaches:

- The coincident peak method;
- The non-coincident peak method; or
- Methods based on a combination of withdrawn volume and contribution to the peak.

5.5.1 Coincident peak method

Under the coincident peak method, the capacity component of the cost of mains is allocated pro rata on the basis of observed peak day demand. The peak is the day on which the highest volume is achieved. This approach assigns peak costs to the customers who are responsible for the peak. The allocation factor is therefore based on the proportion of peak demand caused by each customer class compared with total demand during the period.

This approach has the following salient features:

- The proportions assigned to the various customer classes may vary widely depending on the selected peak day;
- This approach requires that the Distributor have the technical capacity to determine customers' peak demand;
- Under this approach, no capacity is allocated to customers who use less or no gas at peak periods. Therefore, interruptible customers are assigned no capacity-related cost under this method.

The Régie did not choose this approach in the 1985 rate case for three main reasons:

This method falsely assumes that the diameter of each system component was established on the basis of maximum throughput on the peak day of the test year;

- The method assumes that coincident peak demand accurately reflects the relative contribution of each customer class "to the series of decisions […] that led to the creation of the system as it exists at the time of the cost of service study"[41]; and

- The method introduces a random element into the determination of proportion, given the significant variance in the volumes used by customer classes depending on the day on which the peak day occurs. For example, the responsibility of industrial customers will vary according to the whether the peak day is a week day or weekend.

5.5.2 Non-coincident peak method

Under this method, the capacity component of the cost of mains is allocated on the basis of the relative weighting of maximum annual demand for each customer class, regardless of the timing of the demand, over the sum of maximum demands for all customers. The non-coincident peak is the maximum volume that the system could support if all customers withdrew their maximum demand for the year at the same time.

In Decision G-429 of 1985, the Régie rejected this approach on the grounds that the causal relationship between each customer class's responsibility for system capacity and the non-coincident peak was not strong enough. As the non-coincident peak does not occur in practice, it is always greater than the coincident peak and may even be greater than maximum system capacity.[42]

5.5.3 Methods combining a volume withdrawn term and contribution to the peak

Some methods allocate the capacity component of the cost of mains by taking into account capacity used, i.e. volume withdrawn, as well as total available capacity. These methods therefore recognize average capacity utilization in addition to each rate class's responsibility for the design of the system's total capacity. The method used by Gaz Métro belongs to this category.

[41] G-429, p. 85.
[42] G-429, p. 86.

> *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.*[43]

The Régie opted for this approach in its 1985 Decision and the capacity portion of the cost of mains is still allocated by this method, which combines a "capacity used" term and a "capacity attributed" term.

Capacity attributed is based on each customer class's contribution to the coincident peak. The cost of this capacity is estimated by multiplying the capacity attributed by the daily peak cost.

Capacity used is a measure of the difference between volume withdrawn and volume at the coincident peak. Volume withdrawn in excess of capacity attributed (coincident peak) is charged while volume withdrawn below capacity attributed to each class is credited.

The Régie held that the capacity attributed and used (CAU) method was simple to apply and easy to understand, making it transparent.

> *The CAU method appears complex in this detailed presentation but in fact is perfectly simple since it is the coincident peak method (capacity attributed component) modified by adding charges and credits for the capacity used component.* (G429, page 116)

The method for calculating CAU is described in Appendix A to Exhibit Gaz Métro-13, Document 8, in the 2012 rate case (R-3752-2011).

5.5.4 Dr. Overcast's assessment of the CAU

Dr. Overcast, who supported Gaz Métro's reflection on the issue, believes there is no reason to take volume withdrawn into account in allocating the capacity component since there is no causal relationship between those volumes and the cost of mains. He notes that the utilization rate of mains has no impact on their cost.

[43] Black & Veatch, *Review of Gaz Metro's cost of service and rate design*, p. 8.

> *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.*[44]
>
> *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 cost of mains.*[45]
>
> *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.*[46]

In response to our written question, Dr. Overcast provided the following clarification:

> Q: *Could you briefly explain why a volumetric component is not appropriate for allocation of distribution mains or point out where in the text this is explained.*
>
> *A: Main costs do not vary with volume. There are several ways to illustrate this concept. First, if the costs varied with volume regulators would require a weather normalization adjustment of the costs. They do not. Second, once the main is sized based on design day demand, adding load such as a pool heater to be used in the spring and fall has no impact on the size of main but a large impact on volume. Also, adding cooking or clothes drying in a residence increases volume but has no impact on main costs. A high load factor customer and a low load factor customer with the same design day demand have the same impact on costs because they cause the same capacity requirement. Volume simply does not cause costs for either distribution or transmission main. If it does not cause costs it should not be used to allocate costs. We have also shown this to be true empirically as you noted above*.[47]

Dr. Overcast therefore suggests that the capacity component be allocated on the basis of CA as determined by maximum daily demand (maximum daily design), with an adjustment to take interruptible customers into account for the distribution portion of the system.

[44] Black & Veatch, *Review of Gaz Metro's cost of service and rate design*, p. 3.
[45] Black & Veatch, *Review of Gaz Metro's cost of service and rate design*, p. 7.
[46] Black & Veatch, *Review of Gaz Metro's cost of service and rate design*, p. 8..
[47] Correspondence between Gaz Métro and Dr. Overcast.

He also recommended that transmission main costs be allocated solely on the basis of the capacity component, as is currently Gaz Métro's practice.

Finally, interruptible service customers should not be allocated transmission main costs since there is no causal relationship between transmission main capacity and the presence of this customer class.

> *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.*
>
> *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 not served by the capacity of 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.*[48]

Dr. Overcast recommends that distribution main costs be calculated on the basis of maximum daily demand (MDD) and that demand from interruptible service customers be included by using the non-coincident peak for this customer class.

Gaz Métro contemplates changing the way the capacity component of mains is estimated in line with Dr. Overcast's recommendation. Analyses will be produced to assess the impact on cost allocation.

[48] Black & Veatch, *Review of Gaz Metro's cost of service and rate design*, pp. 19 and 20.

5.5.5 Suggested treatment of interruptible service customers

Dr. Overcast indicated that, although interruptible service customers are not taken into account in transmission main design, they are factored into the design of supply and distribution mains. Therefore, supply and distribution main costs must be allocated to them as to all other rate classes. Transmission main costs should not be assigned to interruptible service customers since they are not taken into account in transmission main design.

> *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."*[49]
> "*Interruptible customers are not allocated cost of the transmission system because their MDD is not considered in the design of the transmission network.*[50]

Gaz Métro's Engineering Department confirms these statements and testifies to that effect in an exhibit in the 2014 rate case.[51] According to the department's experts, demand from interruptible service customers is not considered in the design of the transmission main system but is considered in the design of supply and distribution mains.

Currently, transmission, supply and distribution main costs are assigned to interruptible service customers but on the basis of their volumes used, not their peak volumes as suggested by Dr. Overcast.

In accordance with Dr. Overcast's recommendation, Gaz Métro contemplates allocating only distribution main costs (including supply mains) to interruptible service customers, based on peak rather than volume used. Analyses will be produced to assess the impact on cost allocation.

[49] Black & Veatch, *Review of Gaz Metro's cost of service and rate design*, p. 19.
[50] Black & Veatch, *Review of Gaz Metro's cost of service and rate design*, p. 19.
[51] R-3837-2013, GM 2, document 13.

An overview of approaches used by gas utilities in the rest of Canada is presented in Appendix 3.

5.6 OTHER CONSIDERATIONS IN MAINS ALLOCATION

5.6.1 Treatment of customers connected directly to a transmission main

According to data from our Engineering Department, three customers are connected directly to transmission mains.

The first has historical annual consumption ranging between 400,000 and 800,000 m³. On the basis of its annual volume, this customer would normally be connected to a distribution main. It is connected to a transmission main because of its geographic location and cost-effectiveness considerations.

The second has slightly higher annual consumption, nearly 1,400,000 m³. However, its required pressure is 103 kPa, which according to the system design technical specifications would call for a connection to the distribution system. Like the first customer, this customer is connected to a transmission main because of its geographic location and cost-effectiveness.

Finally, the third customer is TCE, which is connected to a transmission main because of its high volume and pressure requirements.

It might be asked whether the mains costs allocation process should treat customers connected to a transmission main differently.

Dr. Overcast makes the following recommendation on this point.

> *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.*[52]

[52] Black & Veatch, *Review of Gaz Metro's cost of service and rate design*, p. 8.

According to Dr. Overcast, if a customer is connected to a transmission main, it should not be assigned distribution main costs. However, it should be assigned transmission main costs, which could lead to a higher charge.

> *If a transmission customer is allocated costs of transmission only, there is no minimum system allocation since the minimum system is for distribution. However, transmission customers would typically have a service lateral that should be directly assigned since in all likelihood it is more expensive than the typical service and also metering is likely to be more as well.*[53]

All customers with system access and some delivery capacity must contribute to the access and capacity components, except those connected to mains dedicated to them who are directly assigned the cost of those mains. This category would include, for example, producers that pay the receipt rate. However, when direct assignment is not possible, which is generally the case, customers are allocated their share of the cost of mains, i.e. of the access and capacity components.

Customers who are connected to transmission mains receive system access and capacity, and should be allocated a share of the access and capacity components of system costs unless direct assignment is possible. At first sight, direct assignment does not appear to be easy from a practical point of view nor desirable for the customers in question, as Dr. Overcast suggests.

Gaz Métro proposes to continue allocating a share of the capacity and access components of the cost of mains to those customers without direct assignment or a specific rate, regardless of the type of main to which they are connected.

5.6.2 Need to take region into account in mains allocation

Originally, the allocation factor used to allocate the cost of mains (CONDPRIN) contained no regional weighting. In 1997, this allocation factor was changed to estimate the zero intercept and the CAU on a regional basis rather than for the entire service area. This way of weighting the allocation factor was supposed to avoid making residential customers in Montréal, a region where there was little development at the time, pay for development of the system in other regions. The current CONDPRIN allocation factor is therefore based on estimates of the zero intercept and the CAU for each of the following six regions:

[53] Email correspondence with Dr. Overcast.

1. Montréal
2. Québec City
3. Estrie
4. Mauricie
5. Saguenay
6. Abitibi

This change to the CONDPRIN calculation to reflect regional differences in the cost of mains was justified by the cost causation principle, on which the allocation process is based. The Régie approved this regional allocation in Decision D-97-47.

> *In the Régie's opinion, allocation of the cost of mains by region, using regional maximum daily demand, is a significant improvement over the current method because it more accurately reflects the causal relationship between the cost of mains and the customers for which they were built. The allocation is therefore based on the use of the mains by current customers in the various regions.*[54]

It would however be appropriate to ascertain whether the method of calculating the mains cost allocation factor really makes it possible to allocate costs by region. Allocation by region should be possible if the costs are recorded by region and allocation factors are determined for each region.

Currently, Gaz Métro does not record mains expenses by region. It can only calibrate its allocation factor to reflect the cost of mains in different regions. However, in the last stage of establishing the CONDPRIN allocation factor, the results by region are aggregated to produce a single allocation factor for the entire service area. Customers in different regions are therefore allocated mains costs in exactly the same proportions, regardless of the region in which they are located.

[54] R-3323-95, D-97-47, p. 17.

The result is therefore that Montréal customers are allocated a portion of the cost of mains laid in Saguenay and vice versa. Rate D_4 customers are allocated the same proportion of mains costs regardless of the region in which they are located. This fact was noted by an expert consulted during the case that led to Decision D-97-47.

> *So it is not a regional allocation. First of all, it is not a regional allocation of mains. We call it that, a regional allocation of mains but there is no final sheet that tell us ''Here is what is costs for region one and here is what it costs for region two for each of the customer classes." What we have instead – because for example, we have no data that tells us what it costs an industrial customer in Lac St-Jean versus what is costs for one in Montreal. So we do not have a regional cost allocation. We are allocating the same costs to industrial customers regardless of where they are located. We are allocating the same average costs to the residential customers regardless of where they are located.*[55]

Union Gas is an example of true regional cost allocation. It allocates costs for its two regions separately and sets regional rates that reflect the specific costs for north and south respectively.

In view of the observed difficulties with the current method of factoring regional differences into the cost allocation, Gaz Métro contemplates correcting or abandoning the way such differences are reflected in the allocation of mains costs.

5.6.3 Calculation of maximum daily demand (MDD)

Maximum daily demand is the maximum volume of natural gas withdrawn by a customer or customer group on a single day. The MDD parameter is used to establish the "capacity attributed" (CA) component, which is a factor in calculating CAU. Capacity attributed (CA) is determined for each rate level and region by multiplying maximum daily demand (MDD) by 365 days:

[55] R-3323-95, Ms. Chow's testimony.

Capacity attributed = MDD x 365.

MDD is estimated by linear regression based on monthly or daily records of the volume used by customers or customer groups. The formula for estimating MDD uses daily consumption per customer as the dependent variable and number of degree-days[56] as the independent variable. The maximum daily demand of each customer or customer group is extrapolated by using the coefficients obtained by linear regression and applying a value of 39 heating degree days to the independent variable. This value corresponds to the number of heating degree days for the peak day, which is defined as -26^{0}C. MDD therefore corresponds to peak day demand.

The formula for estimating daily load per customer or group of customers is also used for other purposes by Gaz Métro, such as calculating revenue normalization[57] and determining peak day volume for the supply plan.[58] Improvements have been made to the model over the years but they have not been uniformly applied at Gaz Métro. In the 2008 and 2009 rate cases, the model was enhanced by including variables to take into account wind and weather persistence (variable lag). These were applied to the revenue normalization calculation. However, it is not currently being applied to calculating CA, which is still done by means of the original model based only on usage and number of heating degree days. Gaz Métro therefore contemplates harmonizing its practices by adding, for the purposes of the CA calculation, the effect of wind on the MDD calculation.

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[56] One degree-day equals a daily mean temperature that is 1^0 C below the base temperature. So, a day on which the mean temperature is 11^{0}C equals two heating degree days if the base temperature is 13^{0}C. A day on which the mean temperature is higher than or equal to the base temperature equals 0 degree-days.

[57] Since 1979, Gaz Métro has been using a revenue stabilization mechanization to stabilize revenues by correcting them to what they would have been if winter temperatures had been normal.

[58] The estimate of peak day demand is used to determine the supply facilities (transmission and storage capacity) required to ensure secure supply for all customers.

It should also be noted that the Rate D_4 peak is calculated not on the basis of MDD but rather maximum hourly demand (MHD). Gaz Métro intends to look at the peak estimation method for each rate, whether it is based on MDD or MHD, and to propose any necessary adjustments.

Gaz Métro believes that the MDD used in the cost allocation process should be estimated using the same factors as those used to establish peak day volumes and to calculate revenue normalization. Gaz Métro therefore contemplates changing its method for estimating MDD for cost allocation purposes in order to bring it into line with the current revenue normalization method (R-3662-2008 Gaz Métro 12, Doc 2).

5.6.4 Equal treatment of distribution and supply mains

The CONDPRIN allocation factor is currently calibrated to take into account the various types of mains. Theoretically, the costs of transmission mains and supply mains should be assigned directly to the capacity component i.e. on the basis of CAU. The costs of distribution mains should be allocated on the basis of both number of customers and CAU, i.e. to both the access and capacity components. The following table shows this treatment.

Current treatment

	Supply (18%) Transmission (8%)	**Distribution (74%)**	
Costs ($)	Capacity	Capacity	Access
Factor (%)	CAU – Supply	CAU – Dist.	No. of customers

Source: R-3752-2011, GM-13, document 8, Appendix A, page 14.

Supply mains and transmission mains are treated differently than distribution mains in the allocation process because of their different functions. The primary function of the former is to carry natural gas from the city gate to the gas pressure regulator stations, to which the distribution mains are connected. Currently, the functions of supply mains and transmission mains are considered to be similar and are therefore treated in the same fashion in calculating the CONDPRIN allocation factor.

Proportion of supply mains

	Length (metres)	Proportion
Distribution	7,676,861	74.0%
Supply	1,909,022	18.4%
Transmission	789,269	7.6%
Grand total	10,375,151	100.0%

Source: Engineering Department, Gaz Métro, 2012-2013 file

However, there are plans to discuss a review of this classification with our Engineering Department. It seems that supply mains now also serve to distribute natural gas, since hundreds of customers are now connected to them. If supply mains are used to deliver gas directly to customers, they should be treated in the same way as distribution mains in the allocation of distribution costs.

According to data from our Engineering Department, a total of 760 customers are connected to supply mains with an operating pressure of 700 kPa to 2900 kPa.[59] Of this total, the vast majority – 670 customers (88.15%) – are connected directly to a supply main because of their geographic location in relation to the system, and therefore essentially because of cost and profitability considerations.

In slightly less than twelve percent (11.85%) of cases, customers are connected to a supply main for technical reasons related to their pressure requirement. According to the system design technical specifications manual used by the Engineering Department, all customers that require pressure above 180 kPa must be connected to a supply main. Of this group, some (30 to 40) needed a system extension to serve them.

[59] Extraction of all customers connected directly to mains with a pressure of more than 700 kPa, May 2013.

Analysis of the data produced by the Engineering Department itself therefore confirms the dual function of supply mains, warranting the same treatment as distribution mains.

As noted above, only three customers are currently connected to a transmission main. The function of transmission mains remains to transport natural gas under high pressure from the transmission system to the city gate. Customers who are directly connected to these mains are a marginal case. And they receive system access and delivery capacity in the same way as other customers, even if they are connected to a higher-pressure main.

The treatment of supply mains, as of distribution mains, is confirmed by our Engineering Department, which has prepared an exhibit dealing with this issue, among other things, for the 2014 rate case.[60]

Allocation of the costs of the different types of mains depends on their functions. If supply and distribution mains both serve the dual purpose of providing system access and delivering gas to customers, they should be treated in the same way in the allocation process, regardless of the pressure under which they carry gas.

Gaz Métro contemplates treating supply mains in the same way as distribution mains for cost allocation purposes, as they serve the dual function of providing system access and delivering natural gas to customers. The primary function of the transmission mains is always to transport natural gas to the city gate, even though a few customers are connected directly to a transmission main.

[60] R-3837-2013, Exhibit B-0082, Gaz Métro-2, Document 14, *Critères appliqués à la conception du réseau de distribution.*

6 OTHER ADJUSTMENTS TO COST ALLOCATION

6.1 OTHER ADJUSTMENTS PROPOSED BY DR. OVERCAST

In addition to the afore-mentioned changes to mains allocation, Dr. Overcast made recommendations that can be described as secondary since their impact on cost allocation is less significant.

6.1.1 About allocation of rate base components

a) Dr. Overcast argues that although the "CONDPRIN" allocation factor is configured to take into account the distinction between transmission and distribution mains, it would be preferable to develop a specific factor to allocate transmission main costs.

> *The transmission investment and city gate costs are appropriately allocated on a design day basis after making any direct assignment 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.*[61]

Gaz Métro has not developed a separate allocation factor for transmission mains costs because of practical considerations. Instead, Gaz Métro has calibrated its CONDPRIN factor to take into account the fact that the costs of transmission mains are allocated exclusively on the basis of the capacity component and the access component is not factored in, in accordance with Order G-429.

> *As no customer is connected to a transmission main, the costs of those mains include only a capacity component.*[62]

[61] Black & Veatch, *Review of Gaz Metro's cost of service and rate design*, p. 16.
[62] Order G-429, p. 75.

These practical considerations relate to the accounting data used for cost allocation, which does not distinguish between expenses incurred for transmission and supply mains, and those incurred for distribution mains.

Gaz Métro will assess practical considerations related to the availability of the data required to implement this recommendation from Dr. Overcast and, if applicable, will develop a specific allocation factor for costs related to the transmission mains that deliver natural gas to the city gate.

b) Dr. Overcast questions the use of the "IMMOBILD" allocation factor to allocate general plant expenses. He suggests that since these facilities are used to provide a workplace for employees, the costs should be allocated in the same way as payroll. He also makes a recommendation with respect to the allocation of payroll.

> *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 of mains is classified on 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.*[63]

Gaz Métro will assess the practical considerations related to the availability of the data required to implement this recommendation from Dr. Overcast.

[63] Black & Veatch, *Review of Gaz Metro's cost of service and rate design*, p.18.

6.1.2 About allocation of administrative expenses

c) Dr. Overcast suggests that the various types of administrative expenses should each have their own allocation factor. Currently, administrative expenses are all allocated on the basis of the EXPLOITD factor, which is derived from the distribution of total operating expenses.

Slightly more than 90% of administrative expenses are related to salaries and fringe benefits. A summary analysis of administrative expenses shows that they include slightly fewer than 150 line items.

Dr. Overcast suggests that payroll be allocated taking into account the nature of the duties for which the salaries are paid, which would be more consistent with cost causation. For example, the salaries of customer service employees should be allocated on the basis of the number of customers while the salaries of mains maintenance employees should be assigned using a mixed factor that takes into account number of customers and volume.

> *Administrative expenses fall into 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*.[64]

In the 2013 rate case, an analysis of the possibility of dividing administrative expenses into different groups was filed and a proposal was formulated.[65] At that time, Gaz Métro was not proposing any changes to the method for allocating administrative expenses, as it felt the cost of establishing a more precise allocation would exceed the resulting benefits.

[64] Black & Veatch, *Review of Gaz Metro's cost of service and rate design*, p.20.
[65] R-3809-2012, Gaz Métro 14, document 2, pp. 4-7.

Gaz Métro holds to its initial view that while allocating each of the 150 line items separately would certainly be a more rigorous approach, it would also be a painstaking process and may not have much impact on the final result. Nevertheless, Gaz Métro believes that its expert's recommendation deserves consideration and it will assess how improvements to the allocation of administrative expenses can reasonably be contemplated.

Gaz Métro will consider the possibility of making improvements to the allocation of administrative expenses and propose changes, if appropriate.

d) Dr. Overcast questions the inclusion of the cost of lost gas, gate stations and mercaptan in distribution rates.

> *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 transmission 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*.[66]

Gaz Métro will assess the merits of this recommendation and the practical considerations that could affect its implementation, and propose improvements if appropriate.

[66] Black & Veatch, *Review of Gaz Metro's cost of service and rate design*, p.20.

6.2 OTHER ADJUSTMENTS CONTEMPLATED BY GAZ MÉTRO

Some proposals related to cost allocation were submitted in the 2013 and 2014 rate cases. In Decisions D-2013-170 and D-2013-106, the Régie decided to deal with them in the present generic case on rate design.

Following the work done on cost allocation in connection with the 2012 rate case, areas for further consideration were identified. Gaz Métro produced a number of analyses of these issues, which have not yet been filed in a rate case.

In this section, Gaz Métro reviews certain points on which proposals have already been made but on which the Régie has not yet ruled, and presents its thinking on subjects that were identified during the 2012 rate case[67] but on which no proposal has yet been submitted.

6.2.1 IT development

Allocation of costs related to IT development was one of the areas for further consideration identified at the end of the work done in connection with the 2012 rate case. A proposal on the issue was submitted in the 2013 rate case.[68]

To strengthen cost causation, Gaz Métro has analyzed the possibility of further breaking down the "IT development" account. At first, this idea was related to the SAP cyclical billing project (SAP2B project). According to the evidence submitted to the Régie (SAP2B project, R-3730-2010, Exhibit Gaz Métro-1, Document 1, p. 4), the SAP2B project consisted in modernizing the computerized billing system for commercial and residential customers. A causal relationship between capital expenditures and market segments could potentially be established for this project

[67] R-3752-2011, Gaz Métro 13, document 8, pp. 26 and 27.
[68] R-3809-2012, Gaz Métro 14, document 2, p. 7.

Current allocation method

"IT development" costs are functionalized entirely to distribution and are found in two places in the cost allocation functionalization exhibit (R-3752-2011, Exhibit B-0163, Gaz Métro-13, document 2):

- The rate base, under the heading Unamortized costs - IT development: this heading includes the costs of all computer projects that are intangible assets and amounts to $27.6 million in the 2010-2011 cost allocation[1]; and

- Distribution costs, under the heading Amortization of deferred costs: when a computer project is completed, it is amortized over a 5-year period. A portion of project costs is recorded in annual amortization of deferred costs. The amount of this item was $11.5 million in the 2010-2011 cost allocation.[2] Exceptionally, some projects such as SAP2B may be amortized over 10 years, with the Régie's approval.

The allocation factor currently used to assign "IT development" costs to both the rate base and amortization of deferred costs is the derivative BASETARD factor, which is based on the total distribution of all rate base costs that have already been allocated using other allocation factors. The resulting allocation of this sum is called BASETARD and is applied to "IT development" costs and the amortization of those costs.

Analyses and avenues explored

Gaz Métro considered whether it was possible to allocate the "IT development" costs functionalized to the rate base and amortization of deferred expenses using a "more direct" method. With a view to strengthening the causal relationship between costs and the customers who generated them, cost allocation by market segment of current IT development costs and SAP2B project costs was analyzed.

[1] R-3752-2011, Gaz Métro-13, Document 2, p. 6, line 216.
[2] R-3752-2011, B-0163, Gaz Métro-13, Document 2, p. 8, line 320.

Current "IT development" costs

An analysis of the nature of the "IT development" costs functionalized to the rate base and amortization of deferred costs found that those costs could not be assigned directly to a market segment because the objectives of IT development projects are too generic. Essentially, those projects are aimed at:

3 maintaining or increasing the productivity of our plant (tangible assets) and intangible assets (computer systems); and

3 ensuring the efficiency and effectiveness of operating activities and operational support activities (e.g.: human resources management, financial management, sales).

By its nature, IT development serves the needs of the entire organization. An attempt was made to break down "IT development" costs by market segment but it was found that there is no specific causal relationship between IT development costs and market segments.

"IT development" costs for the SAP2B project

In the case of the SAP2B project, unlike other IT development projects, it is possible to establish a causal relationship between capital expenditures and market segments, since SAP2B consisted in modernizing the computerized billing system for commercial and residential customers.

The purpose of the SAP2B project was to migrate the FICH cyclical billing system, which was used for billing residential and commercial customers, to SAP. The project not only integrated cyclical billing into SAP but also enriched and enhanced the SAP solution by adding new processes and improving existing ones. A number of these processes are common to all customers, including major industrial accounts. Therefore, the SAP2B project benefitted not only residential and commercial customers but also industrial customers. A cost allocation exercise has been performed on the SAP2B project to distinguish costs associated with all customers from those associated only with residential and commercial customers.

First, CapGemini's "Utilities Process Model+" (UPM+), which includes all the processes covered by the SAP2B solution, was analyzed in order to identify processes that are common to all customers and those that are specific to residential and commercial customers. For example, the "meter management" and "customer relationship management" processes benefit all customers.

Secondly, the development effort for each of these processes was used to estimate the proportion of "IT development" that should be assigned to all customers and the proportion that should be assigned only to residential and commercial customers. It was estimated that:

- 50% of development efforts were devoted to common processes;

- 50% of development efforts were devoted to processes specific to residential and commercial customers.

Therefore, Gaz Métro intends to propose the following allocation of the SAP2B project-related "IT development" costs classified in the rate base and in amortization of deferred costs:

- 50% to all customers, using the BASETARD allocation factor;

3

3 50% to residential and commercial customers, using a new allocation factor: BASETARD-13;

3 this new factor would be prorated to the BASETARD factor for rates D_1 and D_3 as follows:

Cost allocation	D_1	D_3	D_4	D_5
BASETARD	X%	Y%	Z%	W%
BASETARD-13	X / (X+Y)%	Y / (X+Y)%	-	-

The proposed method, which would apply only to SAP2B project costs, would make it possible to allocate costs more appropriately since it would allocate more costs to residential and commercial customers, whose billing system was the reason for the SAP2B project.

In view of these observations, Gaz Métro does not intend to propose changes to the allocation of IT development costs.

However, for the portion of "IT development" costs related to the SAP2B project, both in the rate base and in amortization of deferred costs, Gaz Métro is planning to propose an allocation method that assigns 50% of costs using the BASETARD factor and the other 50% using the BASETARD-13 factor. The new BASETARD-13 factor would be prorated to the BASETARD factor for rates D_1 and D_3.

6.2.2 Development of the new FEÉ-FR allocation factor

In the 2014 rate case, Gaz Métro advised the Régie that it has developed a new factor for allocation of the amounts accumulated following the dissolution of the Energy Efficiency Fund (FEÉ).[69]

[69] R-3837-2013, Gaz Métro 14, document 1, p. 4.

In Decision D-2012-076, the Régie ruled that the amounts accumulated following dissolution of the FEÉ should be reassigned to the customers that contributed to it. The balance was to be distributed prorated to the distribution revenues generated by rate D_1 and D_3 customers. In accordance with this Decision, the FEÉ-FR allocation factor allocates costs between small and medium load (D_1, D_3) customers, prorated to distribution revenues (FB07D) from each rate, sub-rate and level.

Gaz Métro intends to submit its new FEÉ-FR allocation factor for allocating deferred FEÉ costs to the Régie for approval.

6.2.3 Customer Accounts Department factor

Allocation of the costs listed under Customer Accounts Department ("comptabilité des abonnés" - CDA) is another issue for further consideration identified after the work done in connection with the 2012 rate case. No proposal on this issue has been submitted thus far.

For several years, the CDA factor has been a derivative factor based on the proportions of Customer Accounts Department expenses. Those expenses include:

- Contracts, customer calls, orders
- Meter reading
- Customer billing
- Credit and collection
- Allowance for bad debts
- Customer service
- Selling and entertainment expenses
- Advertising.

This factor is used to allocate customer billing costs.

In the 2012 rate case,[70] Gaz Métro advised the Régie that it had removed from "Customer Accounts Department" the following expenses, which had been included in calculation of the CDA factor:

- Customer service
- Selling and entertainment expenses
- Advertising.

After the working group meetings held in connection with the 2012 rate case, Gaz Métro agreed to perform an in-depth analysis of "customer service" expenses in order to identify its components and determine whether these expenses should be considered part of the "Customer Accounts Department" item.

Gaz Métro began by conducting an analysis of the components of "Customer Accounts Department," which are used to calculate the CDA allocation factor.

This account is made up of the following five items:

- Contracts, customer calls, orders: includes administrative expenses for a number of cost centres, including the customer service department and customer information. These activities are related to customer billing activities.

- Meter reading: contains a single cost centre which includes all activities related to meter reading. This item is directly connected to customer billing.

- Customer billing: also a single cost centre, which includes all activities related to customer billing.

[70] R-3752-2011, Gaz Métro-13, Document 1.

- Credit and collection: a single cost centre which includes all activities related to management of accounts receivable. This item is directly connected to customer billing.

- Allowance for bad debts: includes two cost elements, namely bad debts for cyclical customers and bad debts for large-volume customers. It also includes activities related directly to customer billing.

Secondly, Gaz Métro conducted an in-depth analysis of the sub-elements that make up the "customer service" group in order to determine whether some should be under "customer billing."

Customer service: this account includes 23 cost centres. Some natural groups emerge:

- Operations/acquisition technicians (six cost centres) and Technical services (six cost centres);
  - Type of activity: mostly work on the system and to a lesser extent on customer service lines.
- Business and administration office (nine cost centres);
  - Type of activity: administration and support for technicians.

The other two cost centres are the Operations directorate and Installers. These two cost centres are directly related to activities performed on the system and connecting customers.

The cost centres under "customer service" involve technical activities, mostly related to the system and connecting customers, and related administrative functions. None of these cost centres is related to billing or customer accounts.

Based on these observations, Gaz Métro believes that the relationship between the cost centres and items included under "Customer Accounts Department" and "Customer service" are appropriate. Accordingly, Gaz Métro is not proposing any changes to the method for allocating "customer service" expenses.

In the 2014 rate case, Gaz Métro advised the Régie that a full analysis of operating expenses had been performed and some adjustments had been made to update their treatment.[71] The analysis showed that some costs were not properly classified in the wake of internal changes at Gaz Métro. These costs have therefore been moved to the appropriate accounts.

For example, the "Other expenses - Customer Accounts Department" heading included three cost centres, which involved research and marketing strategy. The nature of these cost centres was recently reviewed. As they are no longer directly related to customer accounts, they have been removed and reclassified under different headings. The cost centre which now relates to the demand forecasting unit has been reclassified under selling and entertainment expenses. The second cost centre, which now relates to the sustainable development unit, has been reclassified under administrative expenses. The third cost centre no longer exists and has therefore been eliminated. These changes had the effect of reducing "Other expenses - Customer Accounts Department" to zero. The adjustments do not affect the allocation method or factors.

6.2.4 GEEP allocation factor

In Decision D-2011-182, the Régie ruled that allocation of Global Energy Efficiency Plan (GEEP) costs should be added to the list of cost allocation issues to be given further consideration. No analysis or proposal concerning this issue has been filed to date. Gaz Métro is therefore presenting a description of the GEEP allocation factor and submitting the improvements that it is contemplating.

[71] R-3837-2013, Gaz Métro 14, document 1, p. 9.

The 2012-2013 GEEP budget is $14.2 million out of total distribution costs of $545.6 million, or 3.1% of the cost of service. The GEEP allocation factor includes the following four blocks:

1. Financial assistance;
2. Operating budget, including development and training costs, marketing, monitoring and evaluation;
3. Operating budget, including other activities, studies, consulting and administration;
4. Deferred costs for GEEP expenses.

Financial assistance:

For Rate D_1, financial assistance in the amount of $7,290,000, or 51.5% of the total GEEP budget, is initially distributed by customer type, based on the program, and then by rate level, based on the distribution provided by the GEEP. This is a direct allocation. Costs for the first level are then allocated by sub-level on the basis of volumes delivered and relative total revenues, equally weighted.

For Rate D_3, D_4 and D_5, the amounts are initially distributed by rate, based on program participants as provided by the GEEP, and then by rate level on the basis of volumes delivered and relative total revenues, equally weighted.

For Rates D_3, D_4 and D_5, Gaz Métro contemplates allocating financial assistance by level for all customers, as in the case of Rate D_1.

Operating budget, including other activities, studies, consulting and administration

The operating budget amounts to $1,055,000 or 7.5% of the total GEEP budget.

Available information from the GEEP: For all rates, administrative costs are broken down by customer type, based on the program.

Treatment for purposes of cost allocation: For each customer type and rate, Gaz Métro distributes these costs among rate levels and the sub-levels of the first level of Rate D_1 on the basis of volumes delivered and relative total revenues, equally weighted.

Gaz Métro contemplates no change to the allocation of this component of the GEEP.

Operating budget, including other activities, studies, consulting and administration

The operating budget is $1,570,000 or 11.1% of the total GEEP budget.

Available information from the GEEP: Only totals are available, not broken down by rate or customer type.

Treatment for purposes of cost allocation: For all rates, Gaz Métro distributes operating budgets among the rates, rate levels and sub-levels on the basis of volumes delivered and relative total revenues, equally weighted.

Contemplated change: When preparing for the rate case, the GEEP team assigns a relative weighting to each GEEP program, based on the effort required for the related activities. This weighting is expressed on a scale of 1 to 5, where 1 means minimum effort and 5 means maximum effort.

The resulting weighting is used to assign the administrative budget, including other GEEP activities, to the various programs on the basis of the required effort for each. This approach has the advantage of strengthening cost causation by assigning to each customer type the administrative effort devoted to developing and analyzing the programs intended for that type.

Gaz Métro contemplates using the relative weighting of the effort required for the related activities to initially distribute administrative costs by customer type.

Deferred costs for GEEP expenses

Deferred costs amount to $174,000 or 1.2% of the total GEEP budget.

Available information from the GEEP: For Rate D_1, GEEP allocates deferred costs according to the observed results during the year for which the costs were deferred. The proportion that each rate and rate level represents of the average amount of financial assistance over the previous two years is then used to allocate the deferred costs.

As in the case of Rate D_1, deferred costs for Rates D_3, D_4 and D_5 consist solely of variances between the budget and actual financial assistance. The amount is therefore allocated on the basis of the proportion that each rate represents of the average amount of financial assistance over the previous two years.

Treatment for purposes of cost allocation: For Rate D_1, deferred costs are initially distributed by rate level based on the distribution provided by the GEEP. The first level is distributed among the sub-levels on the basis of volumes delivered and relative total revenues, equally weighted.

For Rates D_3, D_4 and D_5, the amounts are initially distributed by rate, based on program participants as provided by the GEEP, and then by rate level on the basis of volumes delivered and relative total revenues, equally weighted.

As in the case of financial assistance, for rates D_3, D_4 and D_5 Gaz Métro contemplates using the same methodology for deferred costs as for Rate D_1,.

6.2.5 Revenue allocation factors

In the 2012 rate case, Gaz Métro agreed to evaluate the revenue factors since the significant level of cross-subsidization in Rate D_1 seemed to be causing distortions when negative values were assigned. To ascertain the merits of certain revenue-based allocation factors, Gaz Métro has assessed this apparent problem. No analysis has been filed to date.

The revenue factors that have been analyzed fall into two categories[72]:

1. Net revenue factors for each distribution service: REVNETF, REVNETC, REVNETT, REVNETEE, REVNETEP, REVNETD.

2. Load balancing and inventory-related adjustment revenue factors: FB07E-P, FB07E-E;FB07INVF, FB07INVC, FB07INVT.

Net revenue factors for each distribution service

Net revenue factors are used to allocate income tax costs. In this case, the distortion results from that fact that the distribution revenues generated at certain rate levels are lower than the sum of amortization, taxes, gas costs, operating expenses and discounts at those same levels. In this case, net revenue is negative. This applies to the first levels of Rate D_1, which are heavily cross-subsidized.

The methodology behind the use of net-revenue-based allocation factors was approved by the Régie in Decision D-90-44. In that Decision, the Régie referred to Decision G-429, in which it asked Gaz Métro to strengthen cost causation for expenses. In view of Gaz Métro`s argument, the Régie was satisfied with the demonstration of cost causation and accepted the proposal to distribute income tax according to the net revenue generated by each rate. The issue of the distortion caused by cross-subsidization was raised and it was explained that it was normal that a money-losing rate be assigned an income tax credit rather than an income tax expense.

[72] R-3837-2013, Gaz Métro 14, document 6.

Cost causation is therefore plain and is supported by a Régie decision to that effect.

Load balancing and inventory adjustment revenue factors

The distortion effect observed with respect to the load-balancing service does not derive from the same situation as in the case of the distribution service. In the load-balancing service, the distortion results from the fact that revenues, calculated according to customer consumption profiles (AHP parameters[73]), may be positive (heating profile), neutral (stable profile) or negative (reverse or interruptible profile).

These factors are used to allocate items that are directly related to revenues, such as:

5. load-balancing service working capital;
6. load balancing revenues;
7. revenues from inventory maintenance for the supply, compression and transmission services.

Based on these observations, Gaz Métro believes that cost causation is adequately reflected and there is no reason to conclude that there is a distortion in revenue factors and inventory-related adjustments.

Gaz Métro believes that revenue factors offer the best cost causation for the relevant costs. Based on these preliminary analyses, Gaz Métro does not intend to propose changes to the revenue factors.

[73] **A: A**nnual mean daily load, **H:** Mean daily load in winter (**H**iver), **P: P**eak daily load.

Appendix 1: H. Edwin Overcast's résumé

H. EDWIN OVERCAST

Director

Strategic Planning

Mergers & Acquisitions

Due Diligence Support

Pricing and Rate Design

Economic Analysis

Legislative Analysis

Industry Restructuring

Organizational Management

Competitive Market Analysis

Expert Testimony

Open Access and Unbundling Implementation

1 Education

Virginia Polytechnic Institute and State University, Ph.D., 1972

King College, BA in Economics, 1969

A specialist in the practice areas of regulatory policy and economics, energy pricing and rate design, economic analysis, strategic planning, legislative analysis, industry restructuring analysis, competitive analysis and open access and unbundling implementation.

Professional Employment

1999-Present	Management Consulting Division, Black & Veatch Company Directorr
1989-1999	AGL Resources, Inc. Vice President, Strategy Planning and Business Development
1978-1989	Northeast Utilities Director, Rates and Load Research
1975-1978	Tennessee Valley Authority Economist, Rate Branch
1990-1995	Georgia State University Instructor, Economics (part-time)
1974-1975	East Tennessee State University Assistant Professor of Economics Associate Director of Bureau of Business *and Economic Research*
1972-1974	Elon College Assistant Professor of Economics

Professional Experience

Utility Ratemaking and Regulatory Policy Analysis

Dr. Overcast has been responsible for a wide variety of electric and gas pricing and cost analyses. He has had operational and strategic responsibility for both the electric and gas utility tariff design, including comprehensive unbundling cost analyses and tariff administration. He has provided expert testimony before state and federal regulatory agencies on a number of rate and regulatory policy issues related to unbundling, cost of service (marginal, fully allocated and unbundled cost studies, alternative regulation), performance-based regulation and price cap regulation, strategic and market-sensitive pricing, bypass economics, integrated resource planning, weather normalization adjustments, sales and revenue forecasts, pro forma adjustments and revenue requirements, rate and regulatory policy for cogenerators, energy buy-back rates, revenue sharing and adjustment mechanisms, competition and fuel switching, transmission pricing and a variety of policy issues including unbundling proposals, line extension policy and rate discounting and recovery. He has testified before the FERC in electric, gas and oil pipeline matters. He has also testified before provincial regulatory agencies in Canada on electric and gas matters.

Dr. Overcast has also testified in both federal and state courts on matters related to rate design, mergers and acquisitions, anti-trust and regulatory policy. He has testified before both federal and state legislative bodies on deregulation, restructuring, regulatory policy and other issues arising out of restructuring legislation including stranded cost recovery, competition and public policy.

Economic Analysis

Dr. Overcast has been responsible for variety of economic analyses related to merger and acquisition, new business development, bypass, special contracts, marginal cost, time-of-use pricing, service area expansion, pipeline and other facilities expansion, competitive pricing, anti-trust, municipalization, new product development and others. He has provided forecasts of sales, prices, peak day and other similar analyses for planning and regulatory proceedings. He has prepared economic analyses of unbundling and the potential impact on revenue, earnings, stock price and economic value added.

Strategic Planning

Dr. Overcast has been responsible for the development of strategic plans for both the regulated and non-regulated business units. His experience includes corporate reorganization to position a regulated enterprise to open its markets to competition; the preparation of business plans for regulated and non-regulated companies including energy marketing initiatives and other service providers. He has helped to prepare estimates of financial performance for unregulated energy marketing companies and evaluated joint ventures and a variety of retail marketing plans.

He has participated in the planning for a variety of regulatory initiatives. He has had primary responsibility for the development of the legislative model used in Georgia for permitting open access and unbundling.

Legislative Analysis

Dr. Overcast has been responsible for the assessment of a variety of legislative proposals in the areas of the regulatory policy, restructuring analysis, competition and unbundling. He has participated extensively in the legislative process, testifying before committees, negotiating with various interested parties, and working with the staff of legislators. He has worked extensively with lobbyists providing background material and responding to questions raised during the legislative process. He was appointed by the lieutenant governor to serve on a study committee of the Georgia legislature reviewing issues related to the impact of deregulation on franchise fees.

Competitive Analysis

Dr. Overcast has prepared extensive analysis of competition for residential, commercial and industrial customers. That analysis has included comparisons of total and marginal cost for end-use applications, alternate production technologies, alternate fuel analysis, bypass pipelines, self-generation, cogeneration and other competitive analyses. He has also prepared extensive analysis of potential competitors in the opening of markets. He has managed the competitive alternate fuel program for gas utilities and developed a discount analysis required to avoid uneconomic bypass and to maximize revenue contribution from such discount programs. He has also negotiated contracts to avoid bypass for both gas and electric customers and to displace liquid fuels in vehicles.

Open Access and Unbundling Implementation

Dr. Overcast has had the unique experience of playing a significant role in the complete open access and unbundling implementation for natural gas LDCs. He was instrumental in the design of the model adopted by the Georgia legislature and testified throughout the legislative process on the proposed legislation. After the legislation became law, he oversaw the rate case filing required to implement open access and unbundling. His experience includes cost analysis and rate design for an open access tariff. He has been directly involved in the many facets of unbundling service to all retail customers. His firsthand experience provides him with insight and a unique perspective with respect to the questions that arise as a utility—gas or electric—unbundles.

Publications and Presentations

"Restoring Financial Balance," Public Utilities Fortnightly, November 2011

"Impact of Volatile Fuel Prices on Electric Costs: Stakeholder Tactics," Natural Gas and Electricity, August 2008

"Fixed Cost Recovery: An Inconvenient Truth," American Gas, June 2007

"The Hidden Risks of Regulation and Their Effects on Utility Returns," Natural Gas and Electricity, June 2006.

"Electric Utilities and Risk Compensation, with Richard J. Rudden, Howard S. Gorman and Leonard S. Hyman, EEI Monograph, June 2006.

"Energy Competition Knows No Bounds," presented at the DOE-NARUC North American Summit on Harmonizing Business Practices in Energy Restructuring, November 2000.

"Load Research Troubleshooting—A Pragmatic Approach," presented to the Northeast Regional AEIC Load Research Conference, September 1988.

"Using Load Research Data to Assess Competitive Threats," presented to the Northeast Regional AEIC Load Research Conference, September 1987.

"Using Load Research Data to Design and Analyze Commercial and Industrial Time-of-Day Rates," presented to the International Association of Energy Economists, 1987.

"Pricing in Competitive Markets," presented to the PG&E Energy Expo 1986, April 1986.

"Philosophy of Rate Design," presented to the China Energy Research Society of the China Association for Science and Technology, June 1985.

"Competition in the U.S. Electric Markets," presented to the North American Energy Markets Conference, March 1985.

"Electric Utility Competition in the United States," *Energy Exploration & Exploitation*, 1986.

"Avoided Costs—The Balancing of Objectives," *Proceedings of the Eighth Annual Symposium on Problems of Regulated Industries*, 1982.

"An Overview of Alternative Tariff Structures," *Proceedings of the Eighth Biennial Conference of the Central Electricity Generating Board*, Ontario Hydro and the Tennessee Valley Authority (co-authored).

"A Differential Approach to the Repeated Prisoner's Dilemma," *Theory and Decision*, 1971 (co-authored).

"Problems and Perspectives in Public Choice," *Public Finance and Public Choice*, A Training Program for Local Public Officials, 1974.

"The Economic Impact of the East Tennessee State University Medical School," *The Bureau of Business and Economic Research*, East Tennessee State University, 1975.

"Determinants of the Demand of Substandard Housing," presented at the Western Economic Association Meeting, 1970 (co-presented).

1 **Honors**

Who's Who Worldwide—Business Leaders

Citizens Ambassador Program of People to People International - IAEE Delegate, 1985

SGA Outstanding Professor, Elon College, 1973-1974

Omicron Delta Epsilon, honorary fraternity in Economics

H.B. Earhart Foundation Fellow 1970-1971 and 1971-1972

Woodrow Wilson Fellowship Nominee, 1969

National Science Foundation Undergraduate Internship, 1968

2 **Other Activities**

Appointed by Georgia Lt. Governor to serve on Joint Study Committee on Franchise Fees and Conditions, Rights of Way and Tax Implications of Competitive Markets.

Instructor - AGA and EEI Rate Fundamentals Courses

Conference speaker - SGA, SEGA, AGA, NARUC, trade associations and seminars

Vice President - A Better Chance, Glastonbury, CT

Member and Vice Chairman - Glastonbury Sewer Commission

Appendix 2: Craig Brown's résumé

7 Craig Brown

An experienced project manager, consultant, and financial analyst, Mr. Brown provides consulting expertise in the areas of cost of service and rate design, financial modeling, valuation, depreciation, and risk analysis. He is experienced in projects for electric, gas, water, and wastewater utilities. He has significant experience in performing cost of service and rate design studies for both investor-owned and municipal utilities. His studies include financial forecasting, capital program planning, bond financing support, unbundled cost of service, and dynamic rate design alternatives. He has also performed numerous studies and prepared reports and testimony in the areas of depreciation and valuation, as well as knowledge and experience with risk analysis and statistical modeling.

Principal Consultant

Specialization:
Financial Planning
Cost of Service
Rate Design
Valuation
Depreciation
Risk Analysis

Education
- M.B.A., Finance, Rockhurst University, 2004
- B.S., Hotel and Restaurant Management, University of Missouri, 1997

Professional Associations
- Society of Depreciation Professionals

Year Career Started
1997

Joined Black & Veatch
2004

1. PROJECT EXPERIENCE

8 JEA | Electric Utility Cost of Service and Rate Design Study | 2012

Project Manager and Senior Consultant. Mr. Brown serves as project manager and lead consultant on the Black & Veatch project team, performing a detailed unbundled cost-of-service analysis and rate design rate study for JEA's electric system. The project consisted of three stages; 1) review of JEA's 10-year revenue and revenue requirement forecasting procedure, 2) performing a detailed unbundled cost of service analysis incorporating all the customers served by JEA, 3) designing electric rates based on the cost of service results and the financial aptitude of customers served by the electric system

9 Southern Maryland Electric Cooperative (SMECO) | AMI Business Case | 2012

Expert Witness and Consultant. Mr. Brown led the financial impact and cost benefit analysis of SMECO's AMI Business Case that was filed with the Maryland Public Service Commission (Case No. 9294). He prepared the analysis and provided direct and reply testimony to support the analysis that measured the overall impact of the AMI program using a Total Resource Cost (TRC) test based on the present value of the incremental revenue requirements during the deployment and a ten or fifteen-year post-deployment period. Mr. Brown testified during the hearing in support of the TRC measure as well as supporting a 15-year depreciable life for AMI meters. He also prepared a rate impact analysis that incorporates the AMI Business Case costs and benefits into the SMECO 10-year Financial Forecast to project the rate impacts of the AMI program on SMECO's customer-members.

10 Union Gas, Gaz Metro, Enbridge Gas Distribution (Market Area Shippers) | TransCanada Pipeline Rate Case Support | 2012

Project Manager. Mr. Brown managed a team of Black & Veatch professionals that provided regulatory consulting to a group of Canadian gas distribution utilities in the analysis of a natural gas pipeline rate case filed by TransCanada. He led the development of numerous models of the TCPL filing and prepared various scenarios and sensitivities that modified the revenue requirements, cost allocation, and toll design. The results of these studies were then used by the Market Area Shippers to guide their response to TCPL's filing. Black & Veatch also supported the group's position by filing direct evidence with the National Energy Board (NEB).

11 New York Independent System Operator | Rate Schedule 1 Unbundling Study | 2011

Project Manager and Senior Consultant. Mr. Brown was the project manager for a cost allocation and rate design study for the New York Independent System Operator (NYISO) Rate Schedule 1 (RS-1). RS-1 is the NYISO tariff that recovers NYISO's annual operating budget. Currently, the RS-1 tariff is a bundled rate design, with a single charge based on injection MWh for generators (supply) and one for withdrawals MWh for transmission users (load). The current allocation of costs between load and supply is 80%/20%, respectively. The scope of the Black & Veatch study was to unbundle the NYISO's costs and develop a proposal for an unbundled rate design, along with determining an updated recommendation for the load/supply split of costs if bundled rates are to be continued.

12 Board of Public Utilities (BPU), Kansas City, KS | Electric Utility Financial Forecasting, Revenue Requirements, Cost of Service, and Rate Design | 2010

Project Manager and Senior Consultant. Mr. Brown was the project manager and lead consultant for the BPU in the preparation of financial forecast and revenue requirements, unbundled class cost of service, and rate design for the electric utility. The analysis included development of a comprehensive cost of service model, five year projection of revenue requirements and development of rates to meet the projected capital investment and operating requirements of the utility. Rate design enhancement to the BPU's existing rates include electric heating rates, seasonal rate designs, addition of a Medium General Service class, enhancements to the BPU's fuel recovery charge (Energy Rate Component) and creation of an Environmental Surcharge (ESC) Rider to recover capital costs of mandated environmental projects. Mr. Brown submitted direct and rebuttal testimony supporting the study during the rate hearing process. The recommended rate plan included a four-year series of rate increases that was unanimously approved by the Board.

Mr. Brown has continued to support the BPU on numerous projects since the completion of the rate study including developing time of use rates for industrial customers, an economic development program for the utility, all electric rates for a group of contract customers, contract rates for all electric schools, financial planning and scenario analyses for supply side alternatives, bond financing support including Engineer's Certificates, and litigation support in a customer billing dispute.

13 Newark, DE | Electric Utility Financial Forecasting, Revenue Requirements, Cost of Service, and Rate Design | 2010

Project Manager and Lead Consultant. Mr. Brown was the project manager for a comprehensive rate study for the electric utility of Newark, Delaware. The study included a detailed five-year financial forecast, capital plan financing, unbundled cost of service, and rate design. Rates were redesigned for all principle rate classes. Rate concepts being considered include tiered rate blocks, seasonal rate differentials, partial and full revenue decoupling including straight fixed variable rate design for the city's largest customer, the University of Delaware. The Rate Study included a Stakeholder Communication Program that consisted of a series of presentations to a committee of stakeholders that represented each of the city's rate classes. Stakeholder presentations were held at the completion of each stage of the rate study process to communicate the progress to the community.

14 Missouri Gas Energy | Weather Normalization, Customer Annualization, Rate Design | 2009

Project Manager and Lead Analyst. Mr. Brown was the Project Manager and Lead Analyst in MGE's filing for a gas rate increase before the Missouri Public Service Commission. He lead the analysis that supported direct filed testimony for normal heating degree-days, weather normalization, customer annualization, and rate design. The case emphasized innovative rate decoupling mechanisms in MGE's rate design options, such as maintaining a straight fixed variable (SFV) rate design for the Residential class and expanding SFV rate design for the Small General Service class.

15 Brownsville, TX Public Utilities Board | Financial Forecasting, Revenue Requirements, Unbundled Cost of Service, and Rate Design | 2009–2011

Project Manager and Lead Analyst. Mr. Brown was the Project Manager and Lead Analyst for the Brownsville PUB (BPUB) in the preparation of financial forecast and revenue requirements, unbundled class cost of service, and rate design for the electric utility. The analysis includes development of a comprehensive cost of service model, five year projection of revenue requirements and development of rates to meet the projected capital investment requirements of the utility. The Study included creating Time-of-Use rates and defining the BPUB's policy on net metering. Black & Veatch has continued to support the BPUB with various tasks since the completion of the study including development of a multi-tier, inclining block residential rate design.

16 Various Clients | Depreciation Rate Studies | 2005–2011

Project Manager and Lead Consultant. Mr. Brown has been the lead consultant and project manager on numerous depreciation studies for electric, gas, and water utilities. Mr. Brown has developed depreciation rates for clients using both the whole life and remaining life methods. For mass property accounts, his analyses generally consist of developing average service lives by FERC account using actuarial (retirement rate) analysis or simulated plant balance methods, depending on the available data in and if aged (vintage year) plant records are available. Using average service lives, whole life depreciation rates are developed after factoring in allowance for net salvage. This is followed by an analysis of depreciation reserve to determine any reserve deficiency or excess that would be recovered through a remaining life accrual rate. Benchmarking or survey methods have been used to develop depreciation rates when historical data is not available or unreliable. For unit property (generally electric generation assets or water treatment plants) remaining life depreciation rates are developed using a life-cycle approach that factors in planned retirement dates and interim major and minor additions and replacements. Mr. Brown has performed depreciation studies for the following clients: Old Dominion Electric Cooperative (electric), Santee Cooper (electric and water), Cheyenne Light, Fuel & Power (electric and gas), Black Hills Power (electric), Georgia Transmission Corp (electric), SourceGas (gas), Southern Maryland Electric Coop (electric), Northern Kentucky Water District (water), and Missouri Gas Energy (gas).

17 City of St. Joseph, MO | Revenue Requirements and Cost of Service Rate Studies | 2005–2012

Project Manager and Lead Consultant. For the past eight years, Mr. Brown has served as the lead consultant and project manager for a revenue requirements and cost of service rate study for the municipal wastewater utility of the City of St. Joseph, Missouri. In this role, he is responsible for providing comprehensive financial planning services for the sewer enterprise fund. Tasks included development of five-year revenue requirements, allocation of costs to functional components and design of rates. Mr. Brown has made presentations of the proposed rates and cost allocations to both the city's industrial customers, to City Council, and in public hearings.

18 Black Hills Energy (f/k/a Aquila) | Cost of Service, Rate Design, and Weather Normalization | 2005, 2008

Lead Analyst. Mr. Brown was a key team member in Black Hills Energy's rate cases in its Iowa and Colorado jurisdictions. He assisted in the development of class cost of service, rate design, development of normal heating degree-days (HDDs), and weather normalization analyses in connection with filings for gas rate increases before the Iowa Utilities Board. These analyses included development of normal HDDs using the hinge-fit methodology as an alternative to the traditional NOAA 30-year normals, performing statistical analysis in connection with the weather normalization (heating and grain drying) of sales, synchronization and annualization adjustments, preparation of class cost of service models, rate design, and preparing exhibits for expert witness testimony.

19 City of St. Joseph, MO | Financial Capability Analysis | 2008–2009

Project Manager and Lead Consultant. Mr. Brown prepared an Affordability Analysis for the City to evaluate the potential financial impact of the City's combined sewer overflow (CSO) Long Term Control Plan (LTCP) on the City and its residents. The analysis is a tool used to evaluate the impact of CSO projects on the city and used to negotiate an implementation schedule to construct the EPA mandated projects. The basis of the analysis is the EPA document "Combined Sewer Overflows – Guidance for Financial Capability Assessment and Schedule Development." The result of the analysis is to determine the overall "burden" on the residents of the CSO community, classified as low, mid-range, or high burden.

20 Pacific Gas and Electric | Valuation Studies | 2005–2011

Financial Analyst. Mr. Brown assisted in the development of two comprehensive valuation studies to determine the fair market value of a portion of PG&E's electric transmission and distribution system in Yolo County, California and the South San Joaquin Irrigation District in response to condemnation proceedings related to the desired municipalization of the areas. A model to determine fair market value was developed based on replacement cost new (RCN) and replacement cost new less depreciation (RCNLD) using appropriate Iowa Survivor Curves and Condition Percent tables. The final determination of FMV was adjusted for other factors such as going concern, net salvage liabilities, stranded assets and severance costs.

21 Colorado Springs Utilities | Capital Project Prioritization | 2006, 2009

Lead Analyst. Mr. Brown was the lead analyst on an innovative capital project prioritization process for Colorado Springs Utilities' Raw Water System. The engagement applies the Strategic Value Creation Process to quantify the physical and financial parameters of Capital and O&M projects identified for the utility's raw water system. A wide variety of projects and risk are then prioritized to develop the system capital improvement plan while taking into account utility risk tolerance, budget constraints and other planning criteria.

22 SourceGas, (f/k/a Kinder Morgan) | Rate Case Support | 2006 –2007

Financial Analyst. Mr. Brown assisted on numerous projects for Kinder Morgan's retail gas distribution system. He assisted with the preparation of a depreciation rate study for properties in Wyoming, Colorado, and Nebraska. He prepared models and assisted with testimony preparation related to normal heating degree days (HDDs) and weather normalization adjustments for Wyoming and Nebraska. He also prepared a comprehensive revenue requirements model for Nebraska.

Appendix 3: Approaches adopted by other gas utilities

<u>Alberta</u>

Access component

Alberta's two natural gas distributors, ATCO Gas and Pipelines Ltd. and AltaGas Utilities Inc., are currently subject to a performance incentive mechanism.[74]

However, in the last rate case before the introduction of the incentive mechanism,[75] the Alberta Utilities Commission accepted a negotiated classification of mains as 45% access component and 55% capacity component for AltaGas Utilities Inc.

> *With regard to the COSS, parties agreed, for the purposes of this GRA, Mains Pipe will be classified as 45% customer and 55% demand. In AUI's submission, this classification is not unreasonable as it reflects movement towards a more narrowly defined concept of a ''minimum system." In addition to AUI's outside diameter length approach, AUI notes there are a number of approaches that have been utilized in Alberta and other jurisdictions to determine what portion of the mains is related to demand and what portion is required simply to provide a customer with utility service (i.e. the minimum system). While AUI takes no position on the appropriateness of the methods referenced in the UCA's evidence, it has agreed further analysis of this cost is appropriate. Pending receipt of this additional study, parties have agreed to the above noted classification for the purposes of this GRA*.[76]

For ATCO Gas, the access and capacity components were set at 35% and 65% respectively, also on a negotiated basis.[77]

> *Evidence was provided by the UCA that provided numerous examples of what other jurisdictions use to classify mains. There is no definitive methodology as each method has pros and cons. The SP agreed to classify mains based on a factor that is within the reasonability*.[78]

We note that the reasonable nature of these proportions was a factor in the Commission's decision. There are a number of methods, each of which has its merits, but all of which have drawbacks. The Alberta Utilities Commission therefore accepted negotiated proportions on the grounds that they were reasonable and in line with the results of one of the methods.

[74] Alberta Utilities Commission, Decision 2012-237.
[75] 2008-2009 General Rate Application - Phase II, Negotiated Settlement, AltaGas Utilities Inc.
[76] Alberta Utilities Commission, Decision 2011-073, Appendix 3, p. 9.
[77] Alberta Utilities Commission, Decision 2010-291, p. 28.
[78] Alberta Utilities Commission, Decision 2010-291, p. 28.

Capacity component

Atco and AltaGas Utilities Inc. allocated the capacity component of the cost of mains on the basis of non-coincident peak.[79]

<u>New Brunswick: Enbridge</u>

Access (customer) component

In the 2010 case dealing with the cost of service and the rate structure, the capacity component was estimated on the basis of the minimum system method. In this case, the cost allocation methodology, customer segmentation and rate structure of Enbridge Gas New Brunswick (EGNB) were reviewed.[80] Enbridge was assisted in this process by Dr. Overcast of Black & Veatch, the same expert retained by Gaz Métro.

The parties recognized that the access component included some capacity. To address this flaw in the minimum system approach, the low-volume customer category will not be taken into account in assigning the component capacity of mains costs.

> *The Board determines that, as originally proposed by EGNB, the SGS class will not be allocated any portion of the demand cost*.[81]

Capacity (demand) component

EGNB allocates system capacity costs on the basis of each customer class's demand on the coldest day.

> *EGNB proposes to divide the costs in proportion to each class's contribution to the peak design day demand. To accomplish this, EGNB forecasts the demand put on the system by each class on the coldest day the system is designed to accommodate (the peak design day).*[82]

[79] AUC Decision 2010-291, p. 28, and AUC Decision 2011-073, p. 17.
[80] Decision in the matter of a review of a cost of service study filed by Enbridge Gas New Brunswick LP, December 21, 2010, New Brunswick Energy and Utilities Board.
[81] Decision in the matter of a review of a cost of service study filed by Enbridge Gas New Brunswick LP, December 21, 2010, New Brunswick Energy and Utilities Board, p. 9.
[82] Decision in the matter of a review of a cost of service study filed by Enbridge Gas New Brunswick LP, December 21, 2010, New Brunswick Energy and Utilities Board, p. 9.

Ontario: Enbridge

Enbridge adopted the zero intercept approach to assess the access portion of mains costs in 1994[83] and continues using it to this day.

The capacity component is allocated on the basis of a combination of the coincident peak and non-coincident peak, as discussed in the following excerpt from correspondence with Enbridge:

> Q: *How is the capacity component of mains costs allocated (coincident peak day?). What is the rationale used. If the coincident peak day method is used, how are capacity costs allocated to interruptibles?*
>
> *A: TP, HP, and LP demand allocators are based on the volumetric contribution of each rate class on the peak demand day. For heat sensitive customers, a rate class's contribution to peak is calculated by multiplying the Design Degree day (the max degree day for which the system is designed) by average use per degree day for each rate and revenue class. For Unbundled customers, allocators are Non-Coincident Peak. For example, EGD has some gas-fired power generation customers whose peak consumption is in summer (when electricity consumption is highest in Ontario). In this case, the rate class's total Contract Demand volume is assumed*.

Ontario: Union Gas

Union Gas's service area is divided into two major regions and costs are not allocated by the same method in both regions. Rates are also different for Union South and Union North.

Access (customer) component

Since 2007, Union South and Union North have both been using the minimum system method, which they refer to as "minimum plant."

> *The minimum plant method generates the most consistent and reasonable results. The other methods discussed above vary from year to year, system to system, and can yield illogical values for the customer related portion*.[84]

Capacity (demand) component

Capacity is allocated on the basis of maximum daily demand at Union South.

[83] EBRO-487.
[84] EB-2005-0520, Exhibit G1, tab. 1, p. 9.

At Union North, capacity is allocated using a method that combines capacity attributed and used (peak and average day demand).

> *The allocation of distribution demand costs to customers in Union South is based on the design day demand of firm and interruptible customers served by distribution facilities. Distribution demand costs are allocated to the rate classes in the North area using system peak day demand and system peak and average day demand*.[85]

[85] EB-2011-0210, Exhibit G3, tab. 1, schedule 1, p. 16.