REVIEW OF METHODOLOGIES FOR EVALUATING THE PROFITABILITY OF SYSTEM EXTENSION PROJECTS

B&V PROJECT NO. 195813

PREPARED FOR

Gaz Métro Limited Partnership

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1 Executive Summary

1.1 PURPOSE AND PROJECT SCOPE

Black & Veatch Canada Company ("Black & Veatch") was retained by Gaz Métro Limited Partnership ("Gaz Métro") to identify the underlying principles and best practices used by gas distribution utilities in conjunction with system expansion projects to connect new customers to their gas distribution systems and to evaluate whether the underlying methodology used by Gaz Métro in its project evaluation process was reflective of those principles and practices.

Our review and evaluation was based upon a combination of Black & Veatch's experience in structuring system extension policies and related profitability analyses for other gas and electric distribution utilities in North America and the results of our Peer Group research that we conducted on the practices of other gas distribution utilities in Canada and the United States and the criteria that they used to evaluate the economic viability of projects to connect new customers to their gas distribution systems.

Black & Veatch specifically reviewed each of the inputs[1] or parameters used by Gaz Métro in its IRR[2] calculation model for new projects to determine if the model's underlying methodology reflected the best practices we identified in the gas distribution utility industry. This process involved benchmarking Gaz Métro's current methodology against the economic evaluation of development projects used by other gas distribution utilities in two areas: (1) the economic test used by the utility to evaluate each project's profitability; and (2) the specific parameters included in the utility's economic modeling of project profitability.

We selected the parameters that were examined through our industry research based on the specific parameters included in Gaz Métro's IRR calculation model grouped according to the following broad categories, including:

- General Parameters of the Utility's Profitability Analysis
- Valuation Period (time horizon and basis)
- Determination of New Customers (time period for adding new customers and the requirements to do so)
- Revenues Included in the Utility's Profitability Analysis (estimation of revenues and rates)
- Capital-Related Costs included in the Utility's Profitability Analysis (main extension and service lines, meters and regulators, system reinforcements)

Black & Veatch also identified through its research the practices of other gas utilities related to the criteria they use to evaluate the economic viability of projects to connect new customers to their gas distribution systems, and determined those that were most prevalent. The criteria we examined were as follows:

[1] The inputs that were reviewed excluded Operation and Maintenance ("O&M") Expenses which were the subject of the Phase 3A portion of Docket R-3867-2013 before the Régie de l'énergie.
[2] Internal Rate of Return ("IRR").

- Acceptability criteria
  - By individual project or for a project portfolio
  - IRR greater than the Prospective WACC[3]
  - The availability of other funding programs (e.g., an Extension Fund as used by FortisBC)
  - Different criteria used for the specific projects that require regulatory approval (e.g., Gaz Métro projects greater than $1.5 million)

The results of our Peer Group research efforts and the detailed information we compiled on each gas utility's system extension activities can be found in Appendix A to this Report. In addition, a narrative overview of the principles and practices used by the gas utilities in conjunction with their system extension activities is provided in Section 3 of this Report.

1.2 FINDINGS AND RECOMMENDATIONS

Relevant Economic Principles and Cost Concepts

- Relevant Costs for a Profitability Analysis
  - To conduct a profitability analysis, utilities must identify costs that would vary with a change in the output (the "relevant costs"). Within the context of development projects, the output is the number of new customers being connected to the utility's gas system by the development project. In other words, if a development project induces new costs, those incremental costs should be taken into account in the profitability analysis. If the revenues generated by the project are higher than the incremental costs incurred by the project, the project will induce decreases in gas rates of all customers.
  - Including non-relevant costs in the profitability analysis could lead the utility to create an imbalance between existing and new customers, and to lose the opportunity to achieve economies of scale and scope from the addition of the new customers.
  - Current costs should be used to determine the directly attributable, capital-related costs to connect a new customer (e.g., main extension, service line, meter and regulator) to the gas utility's distribution system. A forward-looking, long-run perspective utilized in the derivation of LRIC does not lend itself to the derivation of directly attributable costs related to the discrete capital investments required to connect each new customer to the gas utility's distribution system.
  - Incremental costs are not the costs of utility plant replacements over time because the replacement of existing plant facilities does not increase the output of the utility system. For example, the cost of a distribution system project undertaken by a gas utility to replace a segment of its existing distribution mains or the cost to replace a gas service line or gas meter at a particular customer's location would not constitute an incremental cost. It is simply the cost of maintaining the existing level of output and not an incremental cost to increase the utility's output.

[3] Weighted Average Cost of Capital ("WACC")

- Economies of Scale and Scope
  - Economies of scale and scope should be recognized when evaluating the balance between new and existing gas customers that is created by a gas utility's profitability method for evaluating system expansion projects.
  - As long as the incremental revenues from a new customer to be served by the gas utility can recover, at a minimum, the directly attributable costs of the proposed new connection to the utility's gas distribution system, any revenues above that minimum level will provide a positive contribution to the recovery of the gas utility's fixed costs that are common to the specific activities and functions of the gas utility's development efforts to add new customers and to continue to serve existing customers.
- Issues Related to Long-Run Incremental Costs (LRIC)
  - Using LRIC costing concepts to establish *each* cost component in a gas utility's economic evaluation of system extension projects could violate the "matching principle" of utility ratemaking (i.e., a utility's revenues derived from rates must match its total cost of service or total revenue requirement approved by the regulator).
  - If LRIC is used as the cost basis in a gas utility's economic evaluation of system extension projects, new customers could subsidize existing customers because the gas utility's revenue requirement and current rates are based on historical, embedded costs while the costs in the profitability model would be based on LRIC – which could be higher than the level of embedded costs underlying the gas utility's current rates.
- Other Considerations
  - A gas utility's existing rates are not designed on an individual customer basis – they are designed on a class average basis. Under this approach, the common fixed costs of providing utility service to a particular rate class are attributed to all customers within the class – not to any one customer. Similarly, the utility's fixed costs that are lumpy in nature and support gas service to both new and existing customers should not be attributed only to new customers in any one particular project, but should be attributed to all new customers on a project portfolio basis.
  - The evaluation of the profitability of system extension projects to serve new customers provides the gas utility with the flexibility needed to add new customers to the gas distribution system who can recover through rates their direct incremental costs of connection (i.e., the main extension, service, meter and regulator) and to recognize that all new customers as a group contribute to the recovery of the gas utility's common fixed costs as part of an overall project portfolio.
  - Determination of the portion of upstream main reinforcements attributable to each new customer can be difficult since the main investment could provide future service to new customers, to all future customers, and/or to existing customers who require additional capacity over the life of the new facilities – which would be viewed as a lumpy system investment.

Relevant Findings from the Peer Group Survey

While the Peer Group survey results do not rise to the level of a "best practices" determination, they do provide value since they indicate the preferences of utility regulators and the range of system extension practices implemented by gas utilities. As detailed in Section 4, the current methods employed by Gaz Métro, and the methods under consideration, are well within the bounds set by the common characteristics of the Peer Group utilities. Further, there are a number of parameters in Gaz Métro's current IRR calculation model that are in close alignment with the Peer Group results.

There is a wide range of methods employed by the Peer Group utilities and there is a clear distinction between the system extension policies of gas utilities in Canada compared to those of gas utilities in the U.S. in terms of the degree of complexity, specificity and managerial flexibility associated with their economic tests, policies and practices.

The Canadian gas utilities apply much more analytical rigor, specificity, and detail to the system expansion evaluation process than U.S. gas utilities typically do. Black & Veatch found that the Canadian gas utilities in the Peer Group utilize system extension practices are largely driven by the views and precedents of the particular provincial regulator, which reflect processes that are typically more comprehensive, well-defined and prescriptive than the processes used by gas utilities in the U.S.

Parameters for Use in Gaz Métro's IRR Calculation Model

Profitability Analysis Method

- Black & Veatch recommends that Gaz Métro continue using its current valuation period of forty (40) years, which is the most common valuation period utilized by the Peer Group utilities and reflects the average life of the capital placed into service during a system extension project.
- Black & Veatch finds that the approach utilized by FortisBC, Union Gas Limited and Enbridge Gas Distribution is a reasonable and well-balanced approach. This method utilizes an individual project P.I. of 0.8 and a project portfolio P.I. of 1.1 as the appropriate profitability targets. Black & Veatch recommends that Gaz Métro adopt this type of approach.
- Black & Veatch recommends that Gaz Métro's indirect development costs that are common to all new customers, and a portion of its system reinforcement costs, should be included only in the profitability analysis for its portfolio of projects.

Revenue Considerations

Gaz Métro is considering a policy where only new customers that are contractually engaged upon commencement of the project can be considered in the project profitability analysis. In light of the consideration to adopt a P.I. of 0.8 for individual projects (if further growth is anticipated) and a P.I. of 1.1 for the portfolio of development projects, Black & Veatch believes the movement to only include engaged customers as of the project commencement date is appropriate.[4] The change from estimating future customer growth to only utilizing engaged customers reduces the revenue projected for each project, but revenue from any future growth of new customers will be considered before accepting a project with a P.I. between 0.8 and 1.0.

Capital-Related Investment Costs

Black & Veatch recommends that Gaz Métro recognize the following capital-related investment costs associated with its system expansion projects to connect new customers:

- **Direct Incremental Development Costs** – the capital-related costs incurred by Gaz Métro to connect *each* new customer to its gas distribution system (development activities).
  - Rate of return on investment, income taxes, depreciation expenses and property taxes for the following customer-related facilities:
    - Distribution mains extension
    - Service (connection) Line
    - Meter
    - Regulator

These types of capital-related costs should be directly assigned to *each* new customer on an *individual project basis*. This is a reasonable and appropriate approach since these customer-related facilities are specifically identified and incrementally incurred to meet the specific needs of each new customer. The service (connection) line, meter and regulator are each discrete units of plant investment so their costs can be derived based on the original cost of the each of the plant components valued at the same time the customer is evaluating the initiation of gas service from Gaz Métro. Based on this approach, the costs of these facilities would be derived on a current cost basis[5] rather than on a LRIC basis.

The cost of the system extension would be derived in a similar manner unless it is an integral part of a more extensive system upgrade. There would then have to be an assessment performed of the purpose and functionality of the upgrade to determine if the investment was designed to serve more than one new customer, and if existing customers would also benefit from this incremental investment. Under that situation, the investment would be more appropriately treated as a *System Incremental Reinforcement Cost* as described below.

- **Indirect General Capitalized Development Costs** – other costs that are incurred by Gaz Métro to connect new customers to its gas distribution system that are common to its overall new customer development activities.

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[4] Incorporating additional customers outside of those initial signed is a realistic premise as more often than not there will be new customer growth beyond the initial customers that are signed when the project commences. It is difficult, however, to ensure that each project is treated similarly over time due to a variety of factors when assigning forecasted future customer growth.
[5] The cost basis is still considered to be "incremental" to Gaz Métro's total cost of service, although it is not incremental in the same sense as LRIC.

- Capitalized General Overhead Expenses
- Capitalized General Contractors Fees

These types of capital-related costs are incurred by Gaz Métro on annual basis and are fixed for a certain range of projects that are undertaken by year so they do not change directly based on the number of new customers connected in that year. In other words, these costs are not related to any particular single project. As a result, Black & Veatch recommends that it is reasonable and appropriate to assign these costs to new customers on a project portfolio basis only because they are indirect common costs that are incurred by Gaz Métro to support the entirety of its development activities for all new customers.

- **System Incremental Reinforcement Costs** – the capital-related costs incurred by Gaz Métro to increase the capacity and operating flexibility of its gas distribution system caused by the addition of new customers (i.e., caused by development activities).

These common capital-related investment costs should be assigned to those customers who created the need for the investment. This type of incremental investment could be required to serve new customers, all future customers, and/or existing customers who require additional capacity depending on the purpose of the investment and the timeframe considered in conjunction with Gaz Métro's ongoing distribution system planning activities.

Due to its system nature, Black & Veatch recommends that such costs should not be attributed to any one particular project, but should be assigned to new customers on a project portfolio basis. In addition, if the purpose and functionality of the particular system project will also enhance gas service to Gaz Métro's existing customers, then some recognition of that fact should be considered by creating a basis to reduce the estimated cost of the investment to new customers that will be used in Gaz Métro's IRR calculation model.

2 Underlying Principles and Concepts Related to the Evaluation of Gas System Extension Projects

This section provides a basic description of the principles of utility economics and the cost concepts used by utilities. It also highlights the relevant costs that should be recognized and included in a profitability analysis of a system extension project (also referred to as a "development project") that is conducted by a gas utility.

2.1 THE PURPOSE AND KEY CHALLENGES OF SYSTEM EXTENSION POLICIES AND PRACTICES

The purpose of a gas utility's system extension policies and practices is threefold in nature: (1) to evaluate the profitability of each system extension project to determine if the project is financially viable; (2) to determine if the gas utility's existing customers are subsidizing the addition of new customers to the gas utility's distribution system; and (3) to determine if a customer contribution is required to fund a portion of the cost of the project, and to quantify the amount of the customer's contribution.

Black & Veatch has identified a number of key challenges that should be addressed when establishing a gas utility's system extension policies and practices, including:

- Striking a proper balance between the gas utility's rates and charges of new and existing customers;
- Attribution of common and lumpy investment costs to customers in evaluating the profitability of system extension projects; and
- Appropriately taking into account the uncertainty of estimates, including the determination of the number, type and gas loads of new customers who are expected to be served at a later point in time from the facilities of a particular development project that are constructed and placed into service by the gas utility.

2.1.1 Striking a Proper Balance between New and Existing Customers

To consider the proper balance between a gas utility's rates and charges of new and existing customers, it is important to understand how growth on the gas distribution system through the addition of new customers impacts the utility, its existing customers and the future rates charged to all customers. While new customers cause the gas utility to incur additional costs, they also help pay for the current costs associated with the ongoing operations of the gas utility. These costs and benefits[6] must be carefully considered when structuring the methodology and supporting analytical model used by the gas utility to evaluate the profitability of its development projects.

The creation of rate benefits to all customers by recovering a gas utility's fixed costs over a greater

[6] Where the "benefits" for new customers are represented by the incremental rate revenues paid by these customers and any reduced unit costs created by spreading the gas utility's existing fixed costs and expenses over a greater level of gas throughput, peak demands and number of customers.

level of gas throughput is captured through the concept of economies of scale.[7] The concept of economies of scope[8] is also applicable to a gas utility's operations. As it relates to the subject of this Report, economies of scope measures the difference between the total costs of serving existing and new customers separately compared to the total costs of serving them simultaneously. As long as the gas utility recovers a sufficient level of revenues from new customers to cover the incremental costs of serving them, the gas utility's existing customers will not be disadvantaged through the need for higher rates. At the same time, new customers will also pay a portion of the costs associated with the ongoing operations of the gas utility ultimately reducing the portion of these costs that are paid by existing customers.[9]

While it is important that existing gas customers do not experience future rate increases due to new customer growth and development projects, it is equally important that new gas customers are not unduly burdened by including in the profitability analysis more than the incremental costs to connect these customers to the utility's gas distribution system. If this occurs, it will create the situation where new customers are subsidizing the gas utility's existing gas customers.

2.1.2 Recognition of Lumpy System Investments

For capacity-related costs such as the investment expenditures incurred by the gas utility to provide additional gas transmission and/or distribution system capacity, it is important to consider the lumpy nature of capital expenditures that are made to accommodate load growth. Even though gas load may grow gradually each month, capital expenditures to build upstream gas transmission or distribution projects are typically done less frequently reflecting the fact that economies of scale exist in upstream projects (i.e., it is more cost-effective on a unit basis when larger projects are undertaken compared to smaller projects). The decision of how much investment, the location, and the timeframe for completing these types of projects is typically made by the gas utility's distribution system planning area as part of the ongoing review of its future capacity needs. Multiple factors are considered by system design and planning professionals including the current gas loads, estimates of short-term and long-term growth in load, right of ways, material costs, gas supply considerations, and modeling of current system capacity. There is not a direct relationship between adding a new customer or undertaking a development project and adding a unit of upstream capacity.

[7] Economies of scale is an economic concept that describes the cost advantage that arises with increased output of a product. Economies of scale arise because of the inverse relationship between the quantity produced and per-unit fixed costs (i.e., the greater the quantity of a good produced, the lower the per-unit fixed cost because these costs are spread out over a larger number of goods). Economies of scale may also reduce variable costs per unit because of operational efficiencies and synergies.

[8] Economies of scope is an economic concept stating that the average total cost of production decreases as a result of increasing the number of different goods produced.

[9] As an example of the economies of scale concept when a utility adds customers, the utility might be able to lower its average unit cost associated with its information technology ("IT") activities, general personnel, billing, or metering functions. The resulting decrease in the utility's average unit costs for these activities benefits all customers, both new and existing, through the lowering of their gas rates over time.

2.1.3 Uncertainty of Estimates

When conducting a system extension analysis, there are a number of inputs that must be estimated and estimates are inherently uncertain. Uncertainty is simply the lack of certainty, and with regard to a gas utility's system extension policies and practices, it is this lack of certainty that manifests itself in the future outcome of numerous inputs that enter into a profitability analysis. Those inputs include, construction costs, timelines for construction, revenue generated from customers, customer growth expectations, the useful life of assets, and any other assumption that may be incorporated into the analysis.

While it is tempting to strive to develop a project profitability analysis that includes an accurate depiction of every element of costs and revenues, it is impractical to do so because of these uncertainty issues. One of the greatest contributions of uncertainty in system extension analyses is the assumed level of revenues as it is highly dependent on the estimated number of customers. Further, uncertainty is difficult to avoid - the estimate either assumes some level of future customer growth or assumes no future customer growth; either way both are assumptions that introduce a degree of uncertainty.

2.2 CONSIDERATION OF UTILITY ECONOMICS AND COST CONCEPTS

This section provides a basic description of the principles of utility economics and the cost concepts and highlights what relevant capital costs should be included in a profitability analysis of development projects. Including non-relevant costs in the profitability analysis could lead to an improper balance between existing and new customers and loss of opportunities for all customers to take advantage of economies of scale/scope as explained in the previous section.

2.2.1 The Concept of Cost Causation

The principle of cost causation addresses the question - which customer or group of customers causes the utility to incur particular types of costs? Cost causation requires the identification of costs that vary with a change in the level of output. An accurate representation of cost causation will take into account the relationship between cost inputs and product or service outputs. For example, within the context of a profitability analysis for development projects, the output of a development project is a new customer being connected to the gas system. Therefore, the cost inputs are those resources that enable the connection of that new customer. These inputs are costs that are directly related to the project and are incremental in nature.

In contrast, a system reinforcement investment represents a cost input that provides for an output represented by a reinforced gas distribution system that can meet the capacity or demand requirements of customers.[10] A single development project causes <u>direct</u> incremental costs to be incurred by the utility, whereas the portfolio of projects causes <u>indirect</u> incremental costs to be incurred, such as system reinforcement investments. This distinction is important for appropriately incorporating the concept of cost causation into the utility's project profitability analysis.

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[10] Determining the precise measure of output for a system reinforcement project is challenging given that the investment could provide future service to new customers, to all future customers, and/or to existing customers who require additional capacity or reliability.

2.2.2 The Concept of Direct Costs and Indirect Common Costs

Direct costs are costs that are directly attributable to a particular project or activity. For development projects, the costs of materials, labor, equipment and all directly incurred expenses for the particular project are direct costs.

Direct costs can also be thought of as the costs related to the identification and isolation of specific plant facilities or expenses incurred exclusively to serve a specific customer or group of customers. Where feasible, the direct assignment of costs best reflect the cost causative characteristics of serving individual customers or groups of customers. For a gas utility's system extension projects, the goal is to identify those costs that can be directly attributable to new gas customers. An example would be a specific gas meter or regulator that is installed for the exclusive use of a particular new customer.

Indirect costs are costs that are not directly attributable to a particular project or activity. For development projects, indirect costs can be thought of as the costs associated with generalized activities that can support more than one project, activity or function of the gas utility.

Further, certain indirect costs can be characterized as overhead-related or common costs. Indirect common costs are the plant-related costs and expenses incurred by a utility that cannot be directly attributable to serving a specific customer or group of customers. One example of an indirect common cost is the cost to set-up, administer and monitor an agreement with a construction contractor who works on numerous types of utility-related projects, including repair, maintenance, and system extensions.

2.2.3 The Concept of Incremental Costs

Incremental costs are those costs that are incurred to produce additional output. Output can be defined as gas sales, peak demand, the number of customers served, or some combination thereof. As described above, when discussing cost causation, different measures of output can be associated with different utility functions and services, and they should be chosen based on their specific cost causative characteristics.

Importantly, incremental costs are not the costs of utility plant replacements over time because the replacement of existing plant facilities does not increase the output of the utility system. For example, the cost of a distribution system project undertaken by a gas utility to replace a segment of its existing distribution mains or the cost to replace a gas service line or gas meter at a particular customer's location would not constitute an incremental cost. It is simply the cost of maintaining the existing level of output and not an incremental cost to increase the utility's output.

Including in a profitability analysis costs relating to maintaining the existing level of output, but only using revenues based on embedded costs would result in unfair treatment of customers. Under this situation, the gas utility's new customers would be held responsible for <u>all</u> changes in capital-related costs while existing customers would receive <u>all</u> of the benefits of having the utility's fixed costs recoverable through lower rates that are designed on a greater level of gas throughput.

2.2.4 Issues Related to Long-Run Incremental Costs (LRIC)

Using LRIC costing concepts to establish each cost component in a gas utility's economic evaluation of system extension projects could violate the "matching principle" of utility ratemaking (i.e., a utility's revenues derived from rates must match its total cost of service or total revenue requirement approved by the regulator).

If LRIC is used as the cost basis in a gas utility's economic evaluation of system extension projects, new customers could subsidize existing customers because the gas utility's revenue requirement and current rates are based on historical, embedded costs while the costs in the profitability model would be based on LRIC – which could be higher than the level of embedded costs underlying the gas utility's current rates.

Therefore, if an LRIC approach is adopted by the utility regulator to define the inputs into the gas utility's system extension profitability analysis, caution must be exercised in order to prevent a mismatch between the embedded costs used to set rates for the utility's existing customers (which are the same rates used to derive the revenues expected from new customers) and the LRIC used to derive the profitability of serving new customers, and the level of any customer contribution required of new customers.

3 Survey of Practices of Other Gas Utilities

As a part of this project, Black & Veatch also researched and reviewed the methodologies used for evaluating the profitability of system extension projects to serve new customers and the related ratemaking policies and tariffs of several Canadian and U.S. gas utilities with similar characteristics to those of Gaz Métro. Black & Veatch also conducted interviews with several utilities to understand the more detailed aspects of their system extension policies.

3.1 THE KEY CONCEPTS AND PRINCIPLES OBSERVED IN THE GENERAL STRUCTURES AND METHODS FOR SYSTEM EXTENSION PROJECTS

We find generally that gas utilities in North America use one of three general methods for determining the portion of the cost of a system extension project that would be funded by a customer contribution; if any, required for the project to proceed. Further, several Peer Group utilities utilize a dollar or footage allowance for projects below a certain price threshold. If the allowance is not sufficient, then a customer contribution is required. If the project is above a certain size, then a profitability analysis is utilized, using either an internal rate of return ("IRR") or discounted cash flow ("DCF") method similar to the current method used by Gaz Métro or a simple revenue test where several years of revenues must fund the costs.[11]

Dollar Allowance Method

This method is based on the amount a customer must contribute to connect to the gas utility's system on a fixed dollar allowance. This allowance is generally referred to as a Construction Allowance[12] and they set the maximum amount of costs a utility will incur to connect a new customer to their system. Generally any costs above the Construction Allowance must be paid for by the customer.

Footage Allowance Method

This method is based on a linear limit to the amount of main or service connection a gas utility will make without a contribution from the customer. In Black & Veatch's 2016 Report entitled, *Marginal Costs of Long Term Delivery Service*,[13] the most common length of the allowance was 100 feet (30.5 m), with some as much as 150 feet. Customers must pay for the connection for needs beyond the length allowed by the utility.

Revenue Test Method or Profitability Test

This method is similar to the approach currently used by Gaz Métro and was also the most common method indicated in the Black & Veatch 2016 Report as 9 of the 19 gas utilities in the peer group use this method. This methodology links the amount of investment the gas utility will make with the expected revenue received from the customer. It is a forecast planning tool to determine if the customer should be connected to the existing gas distribution system and if that customer is

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[11] Simple revenue tests are utilized by ATCO, Enbridge New Brunswick, Chesapeake Utilities, and Interstate Power and Light.

[12] In the U.S. this amount is commonly referred to as a Contribution in Aid of Construction ("CIAC").

[13] The referenced Black & Veatch Report is dated September 22, 2016 and was submitted to the Régie in Phase 3A of Docket R-3867-2013.

required to pay a contribution to do so. The peer utilities presented in Appendix A to this Report all utilize a Revenue Test Method.

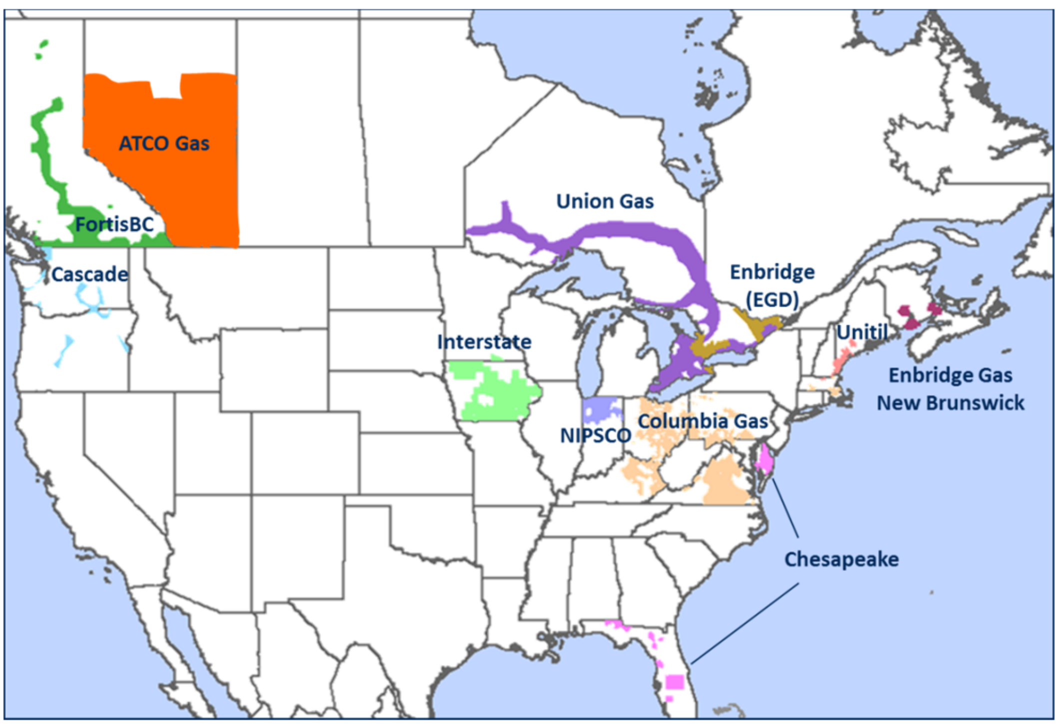
3.1.1 Project or Portfolio Thresholds

In addition to the above methods to evaluate the requirement for a customer contribution, there are also differences in whether the gas utility evaluates individual system extension projects or a portfolio of projects. With project specific thresholds, each project must be viewed as economical on a standalone basis and should only be undertaken by the gas utility if the project is economical; and if a customer contribution will be required based on the specific project economics. In contrast, portfolio thresholds ensure that the gas utility's entire portfolio of development projects will meet a pre-defined Internal Rate of Return ("IRR") threshold; or a Profitability Index ("P.I.") which references the targeted return.[14] For example, Fortis BC, Union Gas Limited and Enbridge Gas Distribution all utilize a P.I. of 0.8 to ascertain if a customer contribution is required for individual main extension projects and a P.I. of 1.1 for the entire portfolio of development projects.

3.2 PEER GROUP OF GAS UTILITIES

In conducting its analysis, Black & Veatch focused its research efforts on a subset of North American utilities in collaboration with Gaz Métro (the "Peer Group").

Figure 1 - Peer Group Map



[14] The dollar and footage allowances may result in a different IRR for each customer, and may or may not require a customer contribution based on the average revenues and costs for the portfolio of system extension projects. Therefore, the threshold is based on average costs with a focus on ensuring all projects in total meet the profitability requirements as utilized in setting the allowance amount.

To create the Peer Group, utilities were selected by Gaz Métro and Black & Veatch based on various high-level characteristics such as geographic location, number of customers, service area size, and customer density.

To better focus on utilities with system extension policies comparable to Gaz Métro, Black & Veatch excluded utilities that did not employ any sort of revenue or economic test in its system extension policies and practices. As a result of those exclusions and with an aim to survey 10-12 utilities the resulting Peer Group was fairly geographically diverse. This illustrates that numerous gas utilities do not utilize a revenue or economic test in their main extension policies.[15]

Figure 1 above and Table 1 below show which utilities were included in the Peer Group.

Table 1 - Peer Group Characteristics

UTILITY NAME	LOCATION OF OPERATION	NUMBER OF CUSTOMERS	AREA SIZE (SQUARE MILES)	CUSTOMER DENSITY (PER SQUARE MILE)
Canadian Gas Utilities				
ATCO Gas	AB	1,100,000	—	—
Enbridge Gas Distribution	ON	2,158,000	10,988	196
Enbridge Gas-New Brunswick	NB	12,000	—	—
FortisBC	BC	982,000	34,667	28
Union Gas Limited	ON	1,400,000	72,132	19
U.S. Gas Utilities				
Cascade Natural Gas	WA	273,365	8,197	33
Chesapeake Utilities	MD, DE, FL	59,546	9,744	6
Columbia Gas (NiSource) [16]	PA, MA, VA, OH, KY, MD	1,161,457	60,174	19
Interstate Power & Light	IA	234,819	36,577	6
Unitil Corporation	ME, NH, MA	76,113	3,295	23

[15] Black & Veatch's 2016 Report dated September 22, 2016 and submitted to the Régie in Phase 3A of Docket R-3867-2013 contains insight into our first Peer Group review which contained gas utilities with and without any revenue or economic test for specific projects.

[16] This report will refer to Columbia Gas of Pennsylvania, Columbia Gas of Massachusetts, Columbia Gas of Virginia, Columbia Gas of Ohio, Columbia Gas of Kentucky, and Columbia Gas of Maryland collectively as "Columbia Gas."

3.3 SURVEY FOCUS AREAS

In conducting its research, Black & Veatch initially set out to understand the system extension policies of the Peer Group at a high level by reviewing the gas utilities' publicly accessible natural gas tariffs. In recognition of the key issues of discussion between Gaz Métro and the Régie, Black & Veatch then focused on researching the characteristics of each utility's economic test applicable to its system extension policies, including the specific parameters that were included in each utility's project profitability model.

To perform this research, Black & Veatch primarily relied upon current publically available documents (e.g., utility tariffs, regulatory filings) that described the methodology used by each gas utility to conduct its profitability analysis. After reviewing these documents, we also conducted interviews with knowledgeable staff from the specific gas utilities to identify and understand the specific parameters used by each utility in its economic or revenue tests for providing gas service to new customers.

Table 2 below summarizes the topics of interest regarding inputs to the project profitability model that Black & Veatch collected data on during its research.

Table 2 - Project Profitability Model - Research Topics

Revenue	Capital Costs
• Customer count • Per-customer revenue • Rate/revenue adjustments • Gas volume adjustment	• Cost of capital • Method to calculate capital costs • Amortization period • Replacement costs • Capital reinforcement • Capitalized overhead

3.4 OVERALL CONTRAST BETWEEN CANADIAN AND U.S. SURVEY RESULTS

Black & Veatch's review of information compiled from utility tariffs, regulatory filings, decisions and utility interviews yielded a number of insights and perspectives for consideration by Gaz Métro in conjunction with the review of its proposed methodology for evaluating the profitability of system extension projects to connect new customers.

Black & Veatch found that the Canadian gas utilities in the Peer Group utilize system extension practices largely driven by their respective provincial regulators, which are typically more comprehensive, well-defined and prescriptive than the processes used by gas utilities in the U.S. The Canadian gas utilities appear to receive more specific direction and review from their regulators than do the U.S. Peer Group utilities.[17] However one commonality was the use of either dollar or footage allowances as ATCO, Union Gas, and Enbridge New Brunswick in Canada as well as at Cascade, Unitil, and Columbia Gas in the U.S.

The system extension policies of FortisBC were most recently revised by the British Columbia Utilities Commission ("BCUC") in its Decision and Order G-147-16, which established specific guidelines for FortisBC's economic test based on consideration of the requested changes proposed by FortisBC and various interveners. FortisBC's valuation period was extended from 20 years to 40 years to better match the expected life of the assets. FortisBC is able to include customers (signed and unsigned) up to Year 5 of its analyses.[18] FortisBC includes various indirect costs related to system extension projects, including a portion of upstream system reinforcement additions and capitalized overhead costs.[19] FortisBC does not include any commodity or midstream capacity costs as the economic test is only applicable to distribution costs, but does include incremental operations and maintenance expenses (O&M) associated with the additional customers for items such as billing and call volumes.

In Ontario, based on the findings of the Ontario Energy Board in its E.B.O. 188 Decision (issued in 1998), gas utilities in Ontario are required to include common elements for estimating capital costs, including:

- An estimate of all costs directly associated with the attachment of the forecasted customer additions (including distribution mains, customer stations, distribution stations, land, and land rights);
- An estimate of the incremental overheads applicable to distribution expansion at the portfolio level; and
- An estimate of the normalized system reinforcement costs.

Gas utilities are also required to include common Operating & Maintenance (O&M) expenses in their economic test calculations when forecasting expenses, including:

- Gas costs as they are used in revenue forecasts (based on the WACOG, excluding commodity costs);[20]

[17] While the system extension policies and practices of the U.S. Peer Group utilities are sanctioned by their state regulatory commission, they typically have more discretion in deciding on the inputs for their profitability analyses; such as assumed customer growth, valuation period, and the methods for developing cost estimates.
[18] If FortisBC can point to the specific plan of a developer or municipal entity showing a build-out horizon longer than 5 years, then a maximum time period is 10 years is allowed.
[19] Overhead costs were approximately 23% of direct capital costs in 2014, but the BCUC approved a sliding scale overhead rate for the utility's projects in its Decision and Order G-147-16 that allows FortisBC to charge a lower overhead rate for larger projects. Upstream system reinforcement additions are applied at a per gigajoule rate to all main extension projects; regardless if the extension is specifically causing the requirement for upstream reinforcement.
[20] The only gas costs to be included in the analysis are related to the transmission and storage assets owned and operated by the gas utility (e.g., Union Gas Limited's Dawn to Parkway gas transmission line) if additional capacity is required to serve the new customers. All commodity costs and upstream capacity costs are excluded from the analysis.

- Incremental operating and maintenance costs;
- Income and capital taxes; and
- Municipal property taxes based on projected levels.

As a utility operating in Ontario, Union Gas Limited complies with the regulations listed above when performing its economic test. Union Gas Limited is also required to perform its economic test for a 40 year period (or 20 years for large volume customers), per the E.B.O. 188 Decision. Union Gas Limited provides a forecast of future customer additions and includes customers expected to attach within the first 10 years of the project in its revenue estimate. To calculate capital costs, Union Gas Limited estimates the incremental investment needed over the 10 year planning horizon to serve its new customers and amortizes the investment over the same 40 year or 20 year valuation period as previously noted.[21] After running these inputs through its model, individual projects larger than the 30 meter extension allowance must achieve at least a P.I. of 0.8 in order for Union Gas Limited to pay for the project in full. Union Gas Limited is also required to ensure that its extension projects on a portfolio basis have an aggregate P.I. above 1.0.[22]

U.S. utilities typically offer new residential customers (and sometimes commercial and industrial customers) footage-based or dollar-based allowances that essentially give any qualifying customer a free main extension and/or service connection if the project requires less footage to be installed or less capital to be spent than provided for by the allowance. Larger projects are typically evaluated by considering the specific capital costs or pipeline footage in excess of the allowance compared to the net revenues a customer or entire new development are expected to generate over a specified period of time. This process in many cases appears to reflect only a high-level evaluation, without considering most indirect costs.

Black & Veatch notes that U.S. utility regulators tend to establish only broad guidelines for the economic tests to financially evaluate system extension projects and provide the gas utility with a fair degree of flexibility in how it actually estimates the additional capital costs and O&M expenses and performs the underlying computations. The larger projects are typically reviewed during rate cases to ensure the utility is prudently applying its discretion so that new customers are not being subsidized by existing customers.

Annual filings for U.S. gas utilities typically only contain information on the number of new customers, the amounts spent on expansions, and the amounts contributed by new customers.

3.5 GENERAL PARAMETERS OF THE PROFITABILITY ANALYSIS

As previously discussed, Black & Veatch's research efforts were mainly focused on understanding the specific inputs used in the Peer Group utilities' project profitability models. The following

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[21] Replacement costs of system extension facilities, such as costs associated with replacing meters, are not included in its model because such costs are considered to be recurring costs that are included and recovered in the utility's current distribution rates.

[22] The OEB set the minimum threshold for the Rolling Project Portfolio [1] at a P. I. of 1.0 and the minimum for an individual project to 0.8. The OEB also set the minimum threshold for the Investment Portfolio[2] to 1.1 which included all distribution business projects necessary to attach customers of all rate classes in a given test year.

sections will discuss the commonalities and differences within the Peer Group on several key parameters that are present in many project profitability models.

3.5.1 Analysis Method

The Peer Group utilities had a range of methods employed to ascertain the need for a customer contribution. Table 3 below provides a summary of the acceptability criteria for each of the Peer Group utilities. It also contains the valuation period for those utilities with a revenue test which will be discussed below.

Table 3 – Peer Group Analysis Method and Valuation Period

Utility Name	Analysis Method	Valuation Period (years)
Canadian Utilities		
ATCO Gas	If the extension is greater than 50 meters, customer must pay ATCO the difference between the cost of construction and the estimated revenue to be generated by the customer in the first 3 years of service (i.e., the contribution is set to recover any shortfall from the equation: (capital cost) – (revenue *3).	N.A.
Enbridge Gas Distribution and Union Gas Limited	The Ontario Energy Board's 188 Decision requires a standardized discounted cash flow (DCF) analysis to be performed using the prospective average cost of capital. The OEB set the minimum threshold for the Rolling Project Portfolio at 1.0 P.I. and the minimum for an individual project to 0.8. The OEB also set the minimum threshold for the Investment Portfolio to 1.1 which included all distribution business projects necessary to attach customers of all rate classes in a given test year. Enbridge and Union utilize a DCF model using their prospective average cost of capital.	40[(a)]
Enbridge Gas New Brunswick	In order for the utility's capital expenditures to be considered prudent, the System Expansion Portfolio test requires that revenues exceed incremental costs by at least 4% (using a revenue-to-cost ratio as the measure).	N.A.
FortisBC	All applications to extend the distribution system to new customers are subject to an economic test. Test is a DCF analysis of projected revenue and costs associated with the extension. If economic test results in P.I. < 0.8, customer can make up the shortfall with CIAC. FortisBC may finance CIAC amounts, and also waive amounts less than $100. There is a P.I. target of 0.8 for individual projects and a P.I. target of 1.1 for the portfolio of projects.	40

Utility Name	Analysis Method	Valuation Period (years)
U.S. Utilities		
Cascade Natural Gas	Cascade offers a generous allowance based on the Perpetual Net Present Value (PNPV) of adding the customer, which is the customer's expected annual net revenue divided by its WACC. Customer pays for construction costs above the allowance.	N.A.
Chesapeake Utilities	For residential, an Internal Rate of Return (IRR) Model is used; for commercial & industrial, a 6 times net revenue test is used. If the IRR of the revenue test is less than the WACC then they require a contribution from the customer.	40
Columbia Gas (NiSource)	Residential: Customer entitled to a set footage allowance for main and or service line extensions. For projects larger than the allowance, customer must pay a contribution equal to the difference between the amount of capital that can be justified on a project (measured by expected revenues) and the minimum capital investment required to serve the customer. Commercial & Industrial: Same as residential but usually with no footage allowance (depending on the state).	40
Interstate Power & Light	If the first 3 years of revenues is greater than or equal to the capital investment than no CIAC is needed. They can extend the 3 years to 5 in certain circumstances. The gas utilities in Iowa are currently in a rulemaking process whereby they are proposing an economic test with 20 years of forecasted revenue in rural areas.	N.A.
Unitil Corporation	In cases where the proposed project does not meet the criteria for a standard allowance, a DCF analysis is run using the WACC, requiring Unitil to show the project can recover its costs or require a customer to make up the shortfall with a CIAC.	20[b]

[a] 20 years for large volume customers
[b] 10 years for residential and commercial customers

3.5.2 Valuation Period

The valuation period refers to the number of years that a utility's profitability model considers cash flows that are expected to be generated by a project. This is distinct from the customer attachment horizon, which is typically less than the valuation period. A longer valuation period typically results in more favorable project economics because it includes more years of revenues to offset the initial capital expenditures. The valuation periods observed within the Peer Group was typically 40 years, as shown in Table 3.

3.5.3 Determination of New Customers

The number of customers that are assumed to attach to a given system expansion project is a key driver to project economics. The utilities surveyed by Black & Veatch had a wide array of policies they employed to derive the customer counts.

Arguably the most important driver of determining the number of customers attaching to a project is the attachment period (sometimes referred to as the attachment horizon), which is the length of time a utility will consider the cash flow impact of new customers attaching to its extension beyond the initial installation period. Some utilities, especially those with simpler economic evaluation methods, do not consider customers who may attach after the installation day in their calculations, and, therefore, have an effective attachment period of zero years.[23] Some U.S. utilities had the flexibility to consider adding future customers who were not necessarily signed such as Columbia Gas (typically 3 years, but up to 5 years, all at their discretion) and Chesapeake Utilities (typically 1-6 years depending on the project). In Canada, policies were set by the provincial regulator in Ontario and British Columbia, where attachment periods were set at 10 years and 5 years, respectively.

Another factor in estimating the number of customers attaching to a project is the method or criteria used to include or exclude customers from the total count. Utilities in the Peer Group typically either require signed contracts to be considered in the economic evaluation or will forecast based on factors such as past experience, consultations with community developers, and customer surveys.

Utilities that were interviewed by Black & Veatch were also asked whether they included any provision for customer attrition during the valuation period (or other time period). None of the utilities interviewed responded that they accounted for this in their analyses.[24]

3.5.4 Revenue-Related Parameters

After deriving an estimate of the number of customers associated with an extension project, the next step is to estimate the amount of revenue or net revenue that can be expected from each customer. Black & Veatch found a wide array of methods used to estimate revenue per customer. One relatively straightforward method is to simply use historical customer class averages to estimate per-customer usage. In some cases, the utility is given latitude to estimate the load based on the best information available and their prior experiences with similar customers. The most common method among the Peer Group involves the utility collecting survey data from its prospective customers and using it to inform their revenue forecast. The utilities collected a wide array of information from prospective customers, depending on the characteristics of the project and the type of customers. For example, Unitil, which operates in New England, collects data such as the square footage of the building, the type of furnace that will be installed, and/or the production load of the plant (for industrial customers).

[23] These include Enbridge Gas New Brunswick, ATCO Gas, Interstate Power & Light, and Unitil Corporation.
[24] Columbia Gas appears to be the only Peer Group utility that did not utilize the full expected revenues as they include a 2.5% reduction in revenues to account for meter inactivity over time.

Black & Veatch also surveyed the Peer Group to see if any of the utilities were making adjustments to their revenue estimates based on expected future rate changes or expected improvements in energy efficiency across the valuation period. None of the utilities surveyed responded that they made either type of adjustment.

3.5.5 Capital-Related Cost Parameters

Black & Veatch researched information on how utilities in the Peer Group arrived at their capital cost estimates. Most utilities use direct dollar outflows associated with the project, and then differ on whether to include indirect costs on top of direct costs.

To arrive at the estimates of direct dollar outflows, utilities typically stated that they estimate capital costs on a project-by-project basis using the best available information before construction. Some utilities such as Interstate Power & Light and Columbia Gas also simplify the process by using a cost per foot metric, especially for smaller projects.

Black & Veatch surveyed the Peer Group to determine whether the replacement costs of the system extension facilities are included in the utilities' economic tests. For example, if the cost of a meter is capitalized in an economic test with a valuation period of 40 years but the meter is expected to last 25 years, the survey sought to determine whether the costs to replace the meter in the 25th year are included in the analysis. It was found that none of the utilities surveyed included this type of cost in their capital cost estimates.

Another topic of interest was whether capital costs associated with upstream system reinforcement were included in the extension project economic tests. Black & Veatch found a wide array of treatment for these costs across the Peer Group. The most frequent response was that these costs were not included in the project economic tests, which was the case for Enbridge Gas New Brunswick, ATCO Gas, Cascade Natural Gas, and Interstate Power & Light. Other gas utilities in the Peer Group such as Union Gas Limited, Unitil Corporation and the Columbia Gas companies[25] consider including these costs in the project extension model on a case-by-case basis. Of all the utilities in the Peer Group, it appears only FortisBC includes a calculated portion of current upstream reinforcement costs related to development projects in their economic tests.

Black & Veatch also assessed whether overhead costs were included in the capital costs in the utilities' economic evaluation models. Types of overheads that were typically included in the Peer Group utilities' analyses were administrative and general, engineering and supervision, as well as internal or external labor. As mentioned in Section 3.4, Union Gas Limited and Enbridge Gas Distribution consider the incremental overheads applicable to distribution expansion at the portfolio level, while FortisBC applies a previously set overhead factor to its direct capital costs to account for overhead costs. FortisBC can also adjust this percentage down for larger projects to account for efficiencies in managing larger projects.[26]

[25] The Columbia Gas Companies stated that they have distinct method for each of their state jurisdictions to ascertain when system reinforcement costs should be included in a project specific economic analysis.
[26] Unitil Gas indicated that they do not include any overhead costs associated with engineering, operations, or corporate.

3.5.6 Other Considerations

Black & Veatch surveyed the Peer Group utilities to understand which types of expenses are included to offset revenues in the utilities' project evaluation models. Most utilities do not include gas supply and transportation costs, with the only exceptions being Union Gas and Enbridge Gas Distribution, as a result of E.B.O. Decision 188.[27] These costs are typically not included because gas supply and transportation costs are a pass through for most utilities, and therefore any increases in their costs would be offset by increased revenues. Further, Black & Veatch inquired of the Peer Group utilities whether they included in their profitability analysis the costs or rebates of any energy efficiency programs for conversions, and none of the utilities we surveyed indicated such financial programs were included in their profitability analyses.

Black & Veatch researched and surveyed the utilities in the Peer Group to understand their reporting requirements and the regulatory review process applicable to their system extension policies. It was found that nearly all of the utilities had some level of reporting responsibility to their respective regulatory commissions. In Ontario, for example, both Union Gas Limited and Enbridge Gas Distribution are required to report on their expansion activities so that the Ontario Energy Board can review its projects on an individual and portfolio basis. Furthermore, they are also required to forecast the rate impacts of their expansion plans and present them in rate case filings on a prospective test year basis. FortisBC is required to periodically perform a Rate Impact Analysis on its main extension test and file it with the British Columbia Utilities Commission. Likewise, most U.S. utilities in the Peer Group are required to report on their system extension policies, often reporting on aspects such as how many customers are added, how many of them pay a CIAC, how accurate the inputs that go into the economic or revenue tests have been, etc.

3.6 IMPLICATIONS FOR GAZ MÉTRO

As evidenced by the wide range of system extension policies and practices of the Peer Group of utilities, the results of Black & Veatch's industry benchmarking research and utility surveys do not provide a clear set of "best practices" for evaluating the profitability of system extension projects to serve new customers. Instead, the results should be characterized as providing "common characteristics" among the various gas utilities surveyed that are influenced by the particular regulatory situation in each province or state.

While the industry survey results do not rise to the level of a "best practices" determination, they do provide some value since they do indicate the preferences of utility regulators and the range of system extension policies and practices implemented by gas utilities. As further detailed in Section 4, the current methods[28] employed by Gaz Métro, and those recently proposed[29], are well within the

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[27] Appendix B of OEB Order 188 states that the utility shall include, "gas costs based on the weighted average cost of gas ("WACOG") excluding commodity costs." Further, the Appendix shows Net Operating Cash equaling Annual Gas Revenue less Annual Gas Costs less Annual O&M; illustrating that gas cost revenue is also included.

[28] The phrase "current methods" refer to the approach generally used by Gaz Metro before the Fall of 2015.

[29] See "Methodology Used to Analyze the Profitability of System Extension Projects," filed on January 20, 2017 and "Methodology for Evaluating the Profitability of System Extension Projects", filed on February 16, 2017 both submitted as additional evidence by Gaz Métro in response to the Régie's Decisions D-2016-09 and D-2016-16.

bounds set by the common characteristics of the Peer Group utilities. Further, there are a number of specific parameters in Gaz Métro's system extension policies and practices that are in close alignment with the Peer Group, as detailed in Section 4.

4 Review and Evaluation of Gaz Métro's Current Methodology for System Extension Projects

This section presents the results of our review and evaluation of Gaz Métro's current system extension policies and practices, and the modifications that were proposed by Gaz Métro in January and February 2017 (its "Early Q1 2017 Filings").[30]

Our evaluation of Gaz Métro's system extension process and related analytical methods was based on how well they aligned with the results of the Peer Group research results and their consistency with, and supportiveness of, the underlying concepts and principles that were presented in Section 2.

As discussed in Section 2, the choice of which analytical method to incorporate into a system extension policy reflects the unique decisions by utilities and regulators in how to best meet the challenges associated with system extension policies (e.g., balancing between new and existing customers, considerations of common and lumpy investments, and uncertainty).

4.1 THE PARAMETERS USED BY GAZ MÉTRO IN ITS IRR CALCULATION MODEL

4.1.1 Profitability Analysis Method

Gaz Métro's current methodology utilizes a profitability analysis that reviews certain costs and expected revenues for a particular system extension project to determine if a customer contribution is needed. This method is generally in alignment with the use of a revenue test or profitability test by the Peer Group utilities. Gaz Métro generally accepts projects with a minimum profitability at the Prospective Weighted Average Cost of Capital ("WACC"), which is often referred to by Gaz Métro as its Prospective Capital Cost ("PCC"). Any individual project that has a return below the PCC might require a customer contribution to be authorized for construction.

Gaz Métro proposed in its Early Q1 2017 Filings to utilize an Acceptable Minimum Threshold based on an IRR of 2% (if further growth is anticipated) since a *posteriori* profitability analysis presented by Gaz Métro demonstrated that the profitability of the extension projects it analyzed increased their combined IRR by an average of 4.48% over the time period that was analyzed. Moreover, in its Early Q1 2017 Filings, Gaz Métro proposed to utilize an exceptions policy where only extensions in industrial parks or road re-pavement projects could be accepted without meeting the acceptable profitability threshold (if further growth is anticipated). The rationale for these exceptions is to take advantage of the timing of these pre-infrastructure projects to minimize costs. For instance, some municipalities do not allow any utility work on repaved or newly paved roads within a certain timeframe.

[30] See "Methodology Used to Analyze the Profitability of System Extension Projects," filed on January 20, 2017 and "Methodology for Evaluating the Profitability of System Extension Projects", filed on February 16, 2017 both submitted as additional evidence by Gaz Métro in response to the Régie's Decisions D-2016-09 and D-2016-16.

4.1.2 Valuation Period

Gaz Métro's current valuation period is forty (40) years, which is close to the weighted average useful life of the incremental assets needed for an extension project. Black & Veatch understands that Gaz Métro has recently reviewed the weighted average useful life of the assets it utilizes in an extension project and found the 40 years to remain a reasonable approximation.

4.1.3 Determination of New Customers

Gaz Métro at times includes contractually engaged customers as well as future probable new customers for an attachment period of generally 5 years. In its Early Q1 2017 Filings, Gaz Métro proposed only the inclusion of contractually engaged customers in the profitability analysis on a going forward basis, to ensure a consistent application of the concept across projects.

4.1.4 Revenue-Related Parameters

The gas volumes used to calculate the revenue in the profitability test are estimated on the basis of the necessary natural gas consumption needs determined jointly by the customer and Gaz Métro. When available, Gaz Métro estimates the natural gas consumption by reviewing a potential customer's existing energy bill or, if no data is available, Gaz Métro will review the types of expected end uses (e.g., heating, hot water, cooking). The average unit charge from each customer's distribution rate is based on their specific gas consumption forecasts.

4.1.5 Capital-Related Cost Parameters

The following costs are currently included as capital-related costs in Gaz Métro's profitability analysis:

- Main Line Costs
- Service Connection Costs
- Meter Costs
- Fees Related to Agreements with Municipalities
- Capitalized General Contractors Fees that cover the contractors' general and administrative costs
- Capitalized General Overhead Expenses (i.e., the portion of general and administrative costs that are capitalized)
- Cost of Removal (i.e., abandonment costs)
- Distribution Reinforcement Costs
- Financial Support Programs (PRC and CASEP)

The Capitalized General Overhead Expenses represents the portion of Gaz Métro total General and Administrative ("G&A") costs that relate to all capitalized projects and is currently allocated at 14.53%, and is calculated by dividing the total of projected year capitalized G&A by the total of the projected year's capitalized cost of the projects. While these Capitalized General Overhead Expenses are allocated among the projects, the total expenses do not vary directly with the number of development projects. Therefore, they can be considered fixed costs for the particular range of projects completed in a year.

The Capitalized General Contractors Fees are an agreed amount paid to Gaz Métro's primary contractors to cover the Contractors' G&A expenses. The rate for 2017 is currently allocated at 27.1% Neither the Capitalized General Expenses nor the Capitalized General Contractors Fees varies directly based on the number and size of Gaz Métro's development projects.

4.1.6 Other Considerations

Gaz Métro has in place a number of financial support and contribution programs. The main financial support program is the PRC. The PRC program provides financial support for gas equipment and associated costs in order to facilitate the choice of natural gas for potential customers. When PRC funds are available to a potential new customer, these funds are currently included in the Gaz Métro's profitability analysis as capital costs which decrease the profitability of the project. An additional fund, CASEP (in French) or PEDA (in English, "Polluting Energies Displacement Account") is a funding program to help convert potential customers from more polluting energy sources to natural gas. These funds are treated in Gaz Métro's profitability analysis as a reduction to capital costs (i.e., they can be used to offset a required customer contribution).

4.2 COMPARISON OF GAZ MÉTRO'S SYSTEM EXTENSION PROCESS WITH THE PEER GROUP SURVEY RESULTS

Table 4 below provides a high level view of the practices of other gas utilities, Gaz Métro's current method, and the changes proposed in Gaz Métro's Early Q1 2017 Filings:

Table 4 – Comparison of Gaz Métro's Process with Peer Group Utilities

ELEMENT	PEER GROUP METHODS	GAZ MÉTRO'S CURRENT METHOD	PROPOSED BY GAZ MÉTRO – EARLY Q1 2017 FILINGS
Profitability Analysis Method	Range of methods employed from allowances for smaller projects to revenue tests and DCF/IRR tests for larger projects. Some utilities set a P.I. separately for the projects than the entire portfolio.	Generally accepts projects with an IRR above current PCC and generally requires CIAC from customers if the IRR is less than the PCC.	Utilize an acceptability minimum of 2% IRR for individual projects if further growth is anticipated. Exceptions only for industrial parks or road re-pavement projects.
Valuation Period	Economic Tests - Ranged from 20-40 years with the most common being 40 years.	40 Years	No Changes Proposed
Determination of New Customers	Varied significantly from secured and signed for delivery upon project completion to estimation of revenues 10 years out.	Includes probable customers, but not necessarily contractually engaged for an attachment period of generally 5 years	Only contractually engaged customers.

ELEMENT	PEER GROUP METHODS	GAZ MÉTRO'S CURRENT METHOD	PROPOSED BY GAZ MÉTRO – EARLY Q1 2017 FILINGS
Revenue-Related Parameters	Varied from utilizing average usage data to specific customer analysis; typically depends on customer size. No inclusion of anticipated decreases.	Reviews either potential customer's existing energy bill or estimates usage based on type of end use.	No Changes Proposed.
Capital-Related Cost Parameters	Typically estimate capital costs on a project-by-project basis using the best available information before construction; either project estimation software or a cost per foot metric, especially for smaller projects. Some overhead costs can be included by project or at a portfolio level for direct overhead associated with the capital investment (e.g., warehouse or delivery loaders, fleet services and fuel, construction labor loaders).	Include the direct capital costs associated with the extension estimated using the best available cost data. Include capitalized General & Administrative costs for both internal Gaz Métro G&A and contractor's G&A that is paid by Gaz Métro as contractors' fees.	No Changes Proposed.
Other Considerations	A few of the Peer Group utilities provided assistance to new customers directly as part of their main extension policies. These programs were either a direct payment by the utility for small CIAC's or financing instruments so they can recover the CIAC through bills over a set amount of time.	Include the costs of the PRC funds as capital costs in their model. Include an offset to capital costs for any CASEP or PEDA funds available for a customer.	No Changes Proposed.

After discussions between Black and Veatch and Gaz Métro on the economic relevant cost concepts and the Peer Group review, Gaz Métro decided to consider a method similar to Fortis BC, Union Gas Limited and Enbridge Gas Distribution, where individual projects with a minimum P.I. of 0.8 are accepted without a CIAC, but on a portfolio basis, the P.I. target is set at 1.1.[31]

The current methods employed by Gaz Métro, and those proposed in the January 2017 Filing, are well within the bounds set by the common characteristics of the Peer Group utilities. There are a variety of approaches employed by the Peer Group utilities. However, Gaz Métro's current and proposed methods fall within the bounds of the Peer Group. In fact, a number of these specific parameters are in close alignment with those of the Peer Group, including:

- The time period for the IRR/DCF analysis that represents the average life of the assets. The most common number of years within the Peer Group utilities is 40 years.
- A threshold that is related to the weighted average cost of capital (i.e., for Gaz Métro - PCC or prospective capital cost).
- A revenue estimate based on a reasonable future expectation for adding new customers or for new customers that are contractually engaged. Gaz Métro is proposing to reduce its discretion by only including contractually engaged customers in its profitability analysis.
- Capital cost estimates on a project-by-project basis using the best available information before construction, with a differentiation in processes for smaller, more straight-forward system extensions and those that are more complex and expensive.
- Inclusion of some reasonable approximation of incremental O&M costs.

More broadly, the current methodology employed by Gaz Métro, and those proposed in the January 2017 Filing meet the following criteria for reasonable system expansion policies:

- Ensure that new customers are treated fairly and consistently;
- Manage the growth of the gas utility's distribution business by providing economic and ratemaking guidelines that ensure no undue rate impact for its existing gas customers;
- Provide business principles and guidelines for capital investments made by the gas utility in support of its new business developmental activities; and
- Provide the gas utility's management team with the flexibility to actively pursue and finalize new customer opportunities in a manner that recognizes the long-term benefits of increased gas throughput for its existing gas customers.

4.3 ADDRESSING THE ISSUE OF UNCERTAINTY IN PROFITABILITY ANALYSIS METHODS

The rate of return utilized in the profitability analysis is a key input to the model. As noted in Section 3, for those gas utilities that utilize a rate of return in their analyses, they utilize their current weighted average cost of capital or prospective capital costs (i.e., the PCC for Gaz Métro). The general concept is that any incremental revenue and the costs of extensions incurred by the utility should at least be sufficient to provide a return equal to the return utilized to set the utility's

[31] It appears there is no material, explicitly stated consequences if a portfolio review results in a P.I. below the 1.1 threshold, but it is reasonable to expect this outcome could initiate a regulatory review of the gas utility's existing policies and practices.

base rates. In a perfect world with no uncertainty, the return calculated by the financial forecast would equal the return ultimately realized by the system extension project. However, uncertainties exist and as described in Section 2.1.3, there are a number of inputs that must be estimated, and estimates are inherently uncertain.

There are two fundamental ways to account for uncertainty in a utility's system extension policies and practices that utilize a profitability analysis. The additional uncertainty can be included in each cost and revenue input by attempting to better align the estimated inputs with future realized outcomes (i.e., become better at estimating). Alternatively, the threshold for profitability can be adjusted to acknowledge the existence of uncertainty. Unfortunately, the first method; attempting to increase the accuracy of each estimate, is not efficient and can be ineffective.[32] However, the second method explicitly addresses uncertainty by acknowledging that a project may have a higher or lower return than forecasted as time passes.

This also illustrates a paradox associated with the parameters of system extension policies and practices - uncertainty cannot be eliminated, it can only be treated differently. For example, the estimate either assumes some level of future customer growth or assumes no future customer growth. Either way, both are assumptions that introduce an element of uncertainty, as you cannot avoid the inclusion of revenue in the utility's profitability model.

This paradox can, however, be addressed by setting a P.I. slightly lower than the WACC/PCC for individual projects and a P.I. above the WACC/PCC for the portfolio of projects.[33] This recognizes the inherent uncertainty in any one project's analysis but still requires that all projects as a portfolio result in investments that have a net benefit to the system as a whole. The paradox can also be addressed by differentiating costs that are appropriate for inclusion in the project profitability analysis from costs that are appropriate for the portfolio review. This recognizes that there is more certainty for direct attributable capital costs in the project profitability analysis than for overhead and system costs that are allocated to any one project.

These insights lead to two core components of the additional changes that are currently under consideration by Gaz Métro following discussions between Black & Veatch and Gaz Métro on the economic relevant cost concepts and the Peer Group review. First, Gaz Métro considers utilizing a P.I. of 0.8 for individual project acceptability and a P.I. of 1.1 for a portfolio of projects. Second, Gaz Métro is considering only including directly attributable, capital-related costs to connect a new customer in the project profitability analysis, whereas indirect overhead and system reinforcement costs would only be included as costs in the portfolio review. Black & Veatch's review and evaluation relating to these two modifications is discussed in detail below.

[32] There will always be inherent bias in estimates (i.e., the difference between the estimator and the true value).

[33] The question to consider is, "Do the biases introduced by uncertainty in each project estimate disadvantage more often new or existing customers?" This can be tested by reviewing the profitability of all projects within the portfolio of system extension projects.

4.4 DIFFERENT TREATMENT OF INDIVIDUAL PROJECTS AND A PORTFOLIO OF PROJECTS

While certain methods can be employed to conduct a project specific profitability analysis, they typically are not appropriate to review the overall profitability of the portfolio of new system extensions. A summary of all individual project profitability analyses also does not provide appropriate insight into a fundamental question - does the incremental revenues and costs of system extensions completed within the specified timeframe increase or reduce customer rates?

For example, while direct costs are easily attributable to any one project, indirect common costs relate more to the entirety of projects undertaken by the gas utility. Often these costs can vary based on both projects relating to existing gas system infrastructure and new extensions as is the case with capitalized G&A costs. It is also difficult to develop an assignment of the Long-Run Incremental Costs ("LRIC") of upstream system reinforcements to each new system extension project since the investments could provide future service to new customers, to all future customers, and/or to existing customers who require additional capacity over the life of the new facilities. Such a system extension project would be viewed as a common and lumpy investment. Further, it is often a subject of contention between utilities and customers where one new customer is deemed to have caused a system reinforcement that benefits other customers located across the gas distribution system.[34]

Developing different thresholds for each individual project and for the portfolio of projects allows for the appropriate consideration of cost principles. Directly attributable costs can be included in the project profitability analysis, while indirect common costs can be included in the overall portfolio profitability analysis. It also reduces the uncertainty of any one project's profitability analysis but while maintaining the overall profitability target.

This concept was discussed by the Ontario Energy Board ("OEB") in their E.B.O 188 Final Report of the Board and the Ontario Energy Board Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario dated January 30, 1998. In this Report, the OEB determined the criteria and the economic tests to be applied to distribution system expansion. The OEB set the minimum threshold for the Rolling Project Portfolio[35] at a P.I. of 1.0[36] and the minimum for an individual project to 0.8. The OEB also set the minimum threshold for the Investment Portfolio[37] to 1.1 which included all distribution business projects necessary to attach customers of all rate classes in a given test year. Finally, Union Gas Limited and Enbridge Gas Distribution consider the incremental overheads applicable to distribution expansion at the portfolio level.

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[34] Black & Veatch recently conducted an electric line extension policy project where one of the focus areas was specifically on the determination of when to attribute system reinforcement costs to a particular line extension project. The general findings were that it is quite difficult to do so, and when it was attempted, it was the basis of significant contention between new customers and the utility.
[35] This is a rolling 12-month distribution expansion portfolio that is the cumulative result of project-specific DCF analyses from the past 12 months, calculated monthly.
[36] Profitability index = (NPV of income + NPV of tax savings) ÷ NPV of investments.
[37] The Investment Portfolio analysis is intended to predict the financial and rate impacts of test year capital expenditures for incremental system expansion projects and associated revenues and expenses.

The distinction between individual project profitability targets and portfolio profitability targets is also made by FortisBC. The use of a 0.80 P.I.[38] as the threshold for accepting an extension project was authorized by the British Columbia Utilities Commission ("BCUC") in December of 2007.[39] The BCUC also set FortisBC's P.I. target for its portfolio of projects to 1.1. For FortisBC, the individual project P.I. target of 0.8 corresponds to an IRR of approximately 3.70%. The portfolio of projects must achieve a P.I. greater than or equal to 1.1, which corresponds to an IRR of approximately 6.02%.

4.5 CATEGORIZATION OF A GAS UTILITY'S SYSTEM EXTENSION CAPITAL INVESTMENTS

For a gas utility such as Gaz Métro, there are different types of facilities supporting its new business development efforts that require the investment of capital to extend its gas distribution system[40] to connect new gas customers. These types of capital investments can be categorized as follows:

- **Direct Incremental Capital Investment -** includes the facilities required to connect *each* new customer in a specific project to the gas utility's existing gas distribution system (development activities).

  Rate of return on investment, income taxes, depreciation expenses and property taxes for the following customer-related facilities:

  - Distribution Mains
  - Service (Connection) Line
  - Meter
  - Regulator

  These costs should be included in the profitability analysis on a project by project basis.

- **Indirect General Capitalized Development Costs** – includes other costs that are incurred to connect new customers to its gas distribution system that are common to its overall new customer developmental activities.

  - Capitalized General Contractors Fees that cover the contractors' general and administrative costs
  - Capitalized General Overhead Expenses (i.e., the portion of general and administrative costs that are capitalized)

  These costs, which are fixed for a certain range of projects done each year, should be considered only at a portfolio level when the profitability of all the development activities is evaluated.

  If these indirect costs are allocated project by project, some projects taken individually could not meet the profitability index criteria. This situation would result in the utility foregoing an

[38] Profitability index = (NPV of net revenues ÷ NPV of investments).
[39] Decision G-152-07: http://www.ordersdecisions.bcuc.com/bcuc/decisions/en/item/111705/index.do.
[40] In certain less frequent situations, a gas utility may need to also expand its gas transmission system to accommodate the connection of new customers to its existing gas distribution system.

opportunity to take advantage of economies of scale and scope - missing an opportunity to decrease rates for its existing customers. Table 5 and Table 6 illustrate this outcome. When $100 of indirect costs is allocated to each project, Table 5 shows that Projects 3 and 4 are not profitable. However, because those two projects have a direct margin of $40 ($20 + $20), as indicated in Table 5, the utility foregoes the opportunity to take advantage of the economies of scale and scope to reduce rates for its existing customers from the $40 of additional margin that would cover other fixed costs. Of course, the $100 of indirect costs will eventually be allocated to all four projects at the end of the year when a profitability analysis is conducted for the overall portfolio of projects.

Table 5 – Example of Allocating Indirect Costs to Individual Projects

PROJECT	REVENUE GENERATED	DIRECT INCREMENTAL COSTS	INDIRECT COSTS AS ALLOCATED	MARGIN
1	$200	$125	$25	$50
2	$200	$100	$25	$75
3	$200	$180	$25	($5)
4	$200	$180	$25	($5)

The yearly indirect costs are equal to $100.

Table 6 – Example of Not Allocating Indirect Costs to Individual Projects

PROJECT	REVENUE GENERATED	DIRECT INCREMENTAL COSTS	INDIRECT COSTS AS ALLOCATED	MARGIN
1	$200	$125	$0	$75
2	$200	$100	$0	$100
3	$200	$180	$0	$20
4	$200	$180	$0	$20

The yearly indirect costs are equal to $100.

- **System Incremental Capital Investment** – includes the capital-related costs incurred to increase the capacity and operating flexibility of the gas distribution system caused by the addition of new customers (i.e., caused by development activities).

  These common capital-related investment costs should be assigned to those customers who created the need for the investment. This type of incremental investment could be required to serve new customers, all future customers, and/or existing customers who require additional capacity depending on the purpose of the investment and the timeframe considered in conjunction with the utility's ongoing distribution system planning activities.

  Those costs should also be considered for inclusion at the portfolio level when the profitability of all the development activities is evaluated.

5 Findings and Recommendations

Based on the results of Black & Veatch's review and evaluation activities described in the earlier sections of this Report, this section summarizes our findings and presents our recommendations related to the economic principles and costing concepts, the results of our Peer Group survey and our review and evaluation of the underlying methodology used by Gaz Métro to evaluate the profitability of its system extension projects.

5.1 RELEVANT ECONOMIC PRINCIPLES AND COST CONCEPTS

This section summarizes Black & Veatch's findings related to the relevant economic principles and cost concepts that should be considered when evaluating the appropriateness of Gaz Métro's profitability analysis for development projects.

- Relevant Costs for a Profitability Analysis
  - To conduct a profitability analysis, utilities must identify costs that would vary with a change in the output (the "relevant costs"). Within the context of development projects, the output is the number of new customers being connected to the utility's gas system by the development project. In other words, if a development project induces new costs, those incremental costs should be taken into account in the profitability analysis. If the revenues generated by the project are higher than the incremental costs incurred by the project, the project will induce decreases in gas rates of all customers.
  - Including non-relevant costs in the profitability analysis could lead the utility to create an imbalance between existing and new customers, and to lose the opportunity to achieve economies of scale and scope from the addition of the new customers.
  - Current costs should be used to determine the directly attributable, capital-related costs to connect a new customer (e.g., main extension, service line, meter and regulator) to the gas utility's distribution system. A forward-looking, long-run perspective utilized in the derivation of LRIC does not lend itself to the derivation of directly attributable costs related to the discrete capital investments required to connect each new customer to the gas utility's distribution system.
  - Incremental costs are not the costs of utility plant replacements over time because the replacement of existing plant facilities does not increase the output of the utility system. For example, the cost of a distribution system project undertaken by a gas utility to replace a segment of its existing distribution mains or the cost to replace a gas service line or gas meter at a particular customer's location would not constitute an incremental cost. It is simply the cost of maintaining the existing level of output and not an incremental cost to increase the utility's output.
- Economies of Scale and Scope
  - Economies of scale and scope should be recognized when evaluating the balance between new and existing gas customers that is created by a gas utility's profitability method for evaluating system expansion projects.

  - As long as the incremental revenues from a new customer to be served by the gas utility can recover, at a minimum, the directly attributable costs of the proposed new connection to the utility's gas distribution system, any revenues above that minimum level will provide a positive contribution to the recovery of the gas utility's fixed costs that are common to the specific activities and functions of the gas utility's development efforts to add new customers and to continue to serve existing customers.

- Issues Related to LRIC
  - Using LRIC costing concepts to establish *each* cost component in a gas utility's economic evaluation of system extension projects could violate the "matching principle" of utility ratemaking (i.e., a utility's revenues derived from rates must match its total cost of service or total revenue requirement approved by the regulator).
  - If LRIC is used as the cost basis in a gas utility's economic evaluation of system extension projects, new customers could subsidize existing customers because the gas utility's revenue requirement and current rates are based on historical, embedded costs while the costs in the profitability model would be based on LRIC – which could be higher than the level of embedded costs underlying the gas utility's current rates.
  - If an LRIC approach is adopted by the utility regulator to define the inputs into the gas utility's system extension profitability analysis, caution must be exercised in order to prevent a mismatch between the embedded costs used to set rates for the utility's existing customers (which are the same rates used to derive the revenues expected from new customers) and the LRIC used to derive the profitability of serving new customers, and the level of any customer contribution required of new customers.

- Other Considerations
  - A gas utility's existing rates are not designed on an individual customer basis – they are designed on a class average basis. Under this approach, the common fixed costs of providing utility service to a particular rate class are attributed to all customers within the class – not to any one customer. Similarly, the utility's fixed costs that are lumpy in nature and support gas service to both new and existing customers should not be attributed only to new customers in any one particular project, but should be attributed to all new customers on a project portfolio basis.
  - The evaluation of the profitability of system extension projects to serve new customers provides the gas utility with the flexibility needed to add new customers to the gas distribution system who can recover through rates their direct incremental costs of connection (i.e., the main extension, service, meter and regulator) and to recognize that all new customers as a group contribute to the recovery of the gas utility's common fixed costs as part of an overall project portfolio.
  - Determination of the portion of upstream main reinforcements attributable to each new customer can be difficult since the main investment could provide future service to new customers, to all future customers, and/or to existing customers who require additional capacity over the life of the new facilities – which would be viewed as a lumpy system investment.

5.2 RELEVANT FINDINGS FROM THE PEER GROUP SURVEY

While the Peer Group survey results do not rise to the level of a "best practices" determination, they do provide value since they indicate the preferences of utility regulators and the range of system extension practices implemented by gas utilities. As detailed in Section 4, the current methods employed by Gaz Métro, and the methods under consideration, are well within the bounds set by the common characteristics of the Peer Group utilities. Further, there are a number of parameters in Gaz Métro's current IRR calculation model that are in close alignment with the Peer Group results.

There is a wide range of methods employed by the Peer Group utilities and there is a clear distinction between the system extension policies of gas utilities in Canada compared to those of gas utilities in the U.S. in terms of the degree of complexity, specificity and managerial flexibility associated with their economic tests, policies and practices.

The Canadian gas utilities apply much more analytical rigor, specificity, and detail to the system expansion evaluation process than U.S. gas utilities typically do. Black & Veatch found that the Canadian gas utilities in the Peer Group utilize system extension practices are largely driven by the views and precedents of the particular provincial regulator, which reflect processes that are typically more comprehensive, well-defined and prescriptive than the processes used by gas utilities in the U.S.

5.3 PARAMETERS FOR USE IN GAZ MÉTRO'S IRR CALCULATION MODEL

Black & Veatch's findings and recommendations are based on the research conducted on the Peer Group utilities, the underlying costing and ratemaking principles that were discussed, and the specific considerations presented in Section 4. Given the interrelationship of the various system extension parameters used by gas utilities, Black & Veatch recommends that these parameters be grouped together rather than addressed separately.[41]

5.3.1 Profitability Analysis Method

- Black & Veatch recommends that Gaz Métro continue using its current valuation period of forty (40) years, which is the most common valuation period utilized by the Peer Group utilities and reflects the average life of the capital placed into service during a system extension project.
- Black & Veatch finds that the approach utilized by FortisBC, Union Gas Limited and Enbridge Gas Distribution is a reasonable and well-balanced approach. This method utilizes an individual project P.I. of 0.8 and a project portfolio P.I. of 1.1 as the appropriate profitability targets. Black & Veatch recommends that Gaz Métro adopt this type of approach.
- Black & Veatch recommends that Gaz Métro's indirect development costs that are common to all new customers, and a portion of its system reinforcement costs, should be included only in the profitability analysis for its portfolio of projects.

[41] For example, keeping the P.I. at 1.0, but only including signed customers does not appropriately account for the propensity for unsigned, future new customers to increase the revenue from a system extension project.

5.3.2 Revenue Considerations

As indicated in Section 4, Gaz Métro is considering a policy where only new customers that are contractually engaged upon commencement of the project can be considered in the project profitability analysis. In light of the consideration to adopt a P.I. of 0.8 for individual projects (if further growth is anticipated) and a P.I. of 1.1 for the portfolio of development projects, Black & Veatch believes the movement to only include engaged customers as of the project commencement date is appropriate.[42] The change from estimating future customer growth to only utilizing engaged customers reduces the revenue projected for each project, but revenue from any future growth of new customers will be considered before accepting a project with a P.I. between 0.8 and 1.0.

5.3.3 Capital-Related Investment Costs

Black & Veatch recommends that Gaz Métro recognize the following capital-related investment costs associated with its system expansion projects to connect new customers:

- **Direct Incremental Development Costs** – the capital-related costs incurred by Gaz Métro to connect *each* new customer to its gas distribution system (development activities).
  - Rate of return on investment, income taxes, depreciation expenses and property taxes for the following customer-related facilities:
    - Distribution mains extension
    - Service (connection) Line
    - Meter
    - Regulator

These types of capital-related costs should be directly assigned to *each* new customer on an *individual project basis*. This is a reasonable and appropriate approach since these customer-related facilities are specifically identified and incrementally incurred to meet the specific needs of each new customer. The service (connection) line, meter and regulator are each discrete units of plant investment so their costs can be derived based on the original cost of the each of the plant components valued at the same time the customer is evaluating the initiation of gas service from Gaz Métro. Based on this approach, the costs of these facilities would be derived on a current cost basis[43] rather than on a LRIC basis.

The cost of the system extension would be derived in a similar manner unless it is an integral part of a more extensive system upgrade. There would then have to be an assessment performed of the purpose and functionality of the upgrade to determine if the investment was designed to serve more than one new customer, and if existing customers would also benefit from this incremental

[42] Incorporating additional customers outside of those initial signed is a realistic premise as more often than not there will be new customer growth beyond the initial customers that are signed when the project commences. It is difficult, however, to ensure that each project is treated similarly over time due to a variety of factors when assigning forecasted future customer growth.

[43] The cost basis is still considered to be "incremental" to Gaz Métro's total cost of service, although it is not incremental in the same sense as LRIC.

investment. Under that situation, the investment would be more appropriately treated as a *System Incremental Reinforcement Cost* as described below.

- **Indirect General Capitalized Development Costs** – other costs that are incurred by Gaz Métro to connect new customers to its gas distribution system that are common to its overall new customer development activities.
  - Capitalized General Overhead Expenses
  - Capitalized General Contractors Fees

These types of capital-related costs are incurred by Gaz Métro on annual basis and are fixed for a certain range of projects that are undertaken by year so they do not change directly based on the number of new customers connected in that year. In other words, these costs are not related to any particular single project. As a result, Black & Veatch recommends that it is reasonable and appropriate to assign these costs to new customers on a project portfolio basis only because they are indirect common costs that are incurred by Gaz Métro to support the entirety of its development activities for all new customers.

- **System Incremental Reinforcement Costs** – the capital-related costs incurred by Gaz Métro to increase the capacity and operating flexibility of its gas distribution system caused by the addition of new customers (i.e., caused by development activities).

These common capital-related investment costs should be assigned to those customers who created the need for the investment. This type of incremental investment could be required to serve new customers, all future customers, and/or existing customers who require additional capacity depending on the purpose of the investment and the timeframe considered in conjunction with Gaz Métro's ongoing distribution system planning activities.

Due to its system nature, Black & Veatch recommends that such costs should not be attributed to any one particular project, but should be assigned to new customers on a project portfolio basis. In addition, if the purpose and functionality of the particular system project will also enhance gas service to Gaz Métro's existing customers, then some recognition of that fact should be considered by creating a basis to reduce the estimated cost of the investment to new customers that will be used in Gaz Métro's IRR calculation model.

Appendix A: Detailed Survey Results of Black & Veatch's Gas Utility Research

GAZ MÉTRO
Profitability of System Extension Projects
Gas Utility Survey Results

Utility Name: ATCO Gas Ltd.
Location: Alberta, Canada

Parameter	Description
System Extension Profitability Analysis Method	If requested service is "Standard Service." Customer pays for installation costs according to Schedule C charges. If the extension is greater than 50 meters (and not Standard Service), customer must pay ATCO the difference between the cost of construction and the estimated revenue to be generated by the customer in the first 3 years of service.
General	
Cost of Capital Assumption	N/A
Basis for Determining the CIAC	ATCO's main extension policy is based largely on a principle of non-discriminatory access to gas service rather than on an overriding concern for the potential subsidization of new gas customers by its existing customers.
Exceptions to the CIAC Basis	If requested service is "Standard Service," Customer pays for installation costs according to Schedule C charges. If the extension is greater than 50 meters in length (and not Standard Service), customer must pay ATCO the difference between the cost of construction and the estimated revenue to be generated by the customer in the first 3 years of service Charges vary by diameter, length, season of construction, service area (north/south). Charges are flat up to 15 meters in length and assessed on a per-meter basis after 15 meters.
Refunds to Year 1 Customers	No
Target Set by Individual Project or All Projects	Individual project
Use of Sensitivity Analyses	No
Different Methods Used Based on the Type of Project	No
Regulatory Requirement for LRMC/LRIC	No
Availability of Funds to Offset Below Target Profitability	No
Regulatory Review Process	None. ATCO operates under a multi-year Performance-Based Regulation (PBR) plan.
Valuation Period	
Number of Years	N/A

Parameter	Description
Basis of Valuation Period	N/A
Determination of New Customers	
New Customers for Year 1 Only	Yes
New Customers for Subsequent Years	No
Criteria Used for Inclusion	N/A
Time Period Used for Adding New Customers – Number of Years	N/A
New Customer Qualification Process	N/A
Recognition of Customer Losses	No
Revenues Included in the Utility's System Extension Profitability Analysis	
Per-Customer Revenue Estimates	N/A
Rate/Revenue Adjustments Made	No
Gas Volume Adjustment to Reflect Customer's Energy Efficiency Activities	No
Capital-Related Costs Included in the Utility's System Extension Profitability Analysis	
Method to Determine the Level of Capital Investment to Connect New Customers	Unknown
Cost Determination Method	Unknown
Amortization Period – Number of Years	N/A
Inclusion of Replacement Costs of System Extension Facilities	No
Inclusion of Capital Reinforcement Costs for Upstream Capacity Additions	No
Inclusion of Capitalized Overhead Costs	Unknown
Other Considerations	
Recognition of Financial Support to Customers in the Analysis	No

GAZ MÉTRO
Profitability of System Extension Projects
Gas Utility Survey Results

Utility Name: Enbridge Gas Distribution
Location: Ontario, Canada

Parameter	Description
System Extension Profitability Analysis Method	Enbridge will extend the system "when it is feasible" based on three factors (see below) impacting the economics of the projects. Customers required to pay CIAC if the benefits do not cover the construction cost.
General	
Cost of Capital Assumption	Incremental after-tax cost of capital based on the prospective capital mix, debt, and preference share cost rates, and the latest approved rate of return on common equity.
Basis for Determining the CIAC	Enbridge will consider the number of customers attaching in the next 5 years, the amount of natural gas to be used, and the cost of extending the gas main when determining the feasibility of the project. If benefits do not exceed costs, CIAC required. The Ontario Energy Board's 188 Decision requires a standardized DCF analysis to be performed. The OEB set the minimum threshold for the Rolling Project Portfolio at 1.0 P.I. and the minimum for an individual project to 0.8. The OEB also set the minimum threshold for the Investment Portfolio to 1.1 which included all distribution business projects necessary to attach customers of all rate classes in a given test year.
Exceptions to the CIAC Basis	Unknown
Refunds to Year 1 Customers	No
Target Set by Individual Project or All Projects	Standards apply to both individual projects and all project portfolios.
Use of Sensitivity Analyses	No
Different Methods Used Based on the Type of Project	No
Regulatory Requirement for LRMC/LRIC	No
Availability of Funds to Offset Below Target Profitability	No
Regulatory Review Process	EBO 188 establishes a mechanism for the regulator to review utilities' expansion activities on an individual project and portfolio basis. Utilities are required to forecast the rate impacts of their expansion plans and present them in rate case filings on a

Parameter	Description
	prospective test year basis.
Valuation Period	
Number of Years	EBO 188 requires a 40 year customer revenue horizon; or 20 years for large volume customers.
Basis of Valuation Period	Regulatory determination (in 1998)
Determination of New Customers	
New Customers for Year 1 Only	No
New Customers for Subsequent Years	5 year attachment period. Factor applied to reflect the timing of forecasted customer additions. EBO 188 requires a 10 year customer attachment horizon.
Criteria Used for Inclusion	EBO 188 requires a forecast for customer attachments during the Customer Attachment Horizon for each project.
Time Period Used for Adding New Customers – Number of Years	5 Years
New Customer Qualification Process	Unknown
Recognition of Customer Losses	No
Revenues Included in the Utility's System Extension Profitability Analysis	
Per-Customer Revenue Estimates	Estimated by company reflecting the mix of customers to be added.
Rate/Revenue Adjustments Made	Rates derived from the existing rate schedules for the particular utility, net of the gas commodity component.
Gas Volume Adjustment to Reflect Customer's Energy Efficiency Activities	No
Capital-Related Costs Included in the Utility's System Extension Profitability Analysis	
Method to Determine the Level of Capital Investment to Connect New Customers	EBO 188 requires utilities to include common elements when calculating capital costs, including: - Estimate of all costs directly associated with the attachment of the forecasted customer additions (including distribution mains, customer stations, distribution stations, land, and land rights) - An estimate of the incremental overheads applicable to distribution expansion at the portfolio level; and - An estimate of the normalized system reinforcement costs

Parameter	Description
Cost Determination Method	The “incremental” investment needed over the 10-year planning horizon to serve the new customers.
Amortization Period – Number of Years	Same as valuation period
Inclusion of Replacement Costs of System Extension Facilities	No
Inclusion of Capital Reinforcement Costs for Upstream Capacity Additions	Yes
Inclusion of Capitalized Overhead Costs	Yes
Other Considerations	
Recognition of Financial Support to Customers in the Analysis	Utility can finance customer’s CIAC.

GAZ MÉTRO
Profitability of System Extension Projects
Gas Utility Survey Results

Utility Name: Enbridge Gas New Brunswick
Location: New Brunswick, Canada

Parameter	Description
System Extension Profitability Analysis Method	System Expansion Portfolio (SEP) Test • EGNB is a relatively new gas distribution utility authorized to distribute natural in the province of New Brunswick in August, 1999, with a Development Period[44] established from June, 2000 through December 31, 2005. • Each year, the regulator assesses the prudency of capital expenditures as part of its retrospective review process. This is carried out using the pre-defined calculations under the SEP test. In order for the utility's capital expenditures to be considered prudent, the SEP test requires that revenues exceed incremental costs by at least 4% (using a revenue-to-cost ratio as the measure).
General	
Cost of Capital Assumption	Utility's current authorized cost of equity and current cost of debt
Basis for Determining the CIAC	The material and installation costs relating to any portion of the main, service line, service connections and appurtenant facilities located on the customer's property that exceeds the portion which EGNB will install without charge. Recovery of labor, materials and overhead costs.
Exceptions to the CIAC Basis	EGNB must provide at no cost a service line of 30 meters in length to connect a residential customer.
Refunds to Year 1 Customers	No
Target Set by Individual Project or All Projects	Portfolio approach
Use of Sensitivity Analyses	No
Different Methods Used Based on the Type of Project	No
Regulatory Requirement for LRMC/LRIC	No
Availability of Funds to Offset Below Target Profitability	No
Regulatory Review Process	• As part of its annual financial reporting to the regulator, EGNB must submit a System Expansion Portfolio (SEP) test which calculates the capital costs and impact on the utility's revenue requirement of expansions for the previous year.

[44] The Development Period is a period during which EGNB cannot be expected to operate like a mature utility because it is still in the early stages of infrastructure development and customer capture.

Parameter	Description
	• SEP must show revenues are at least 4% higher than costs to conclude that the expansions for that year were prudent investments.
Valuation Period	
Number of Years	N/A
Basis of Valuation Period	N/A
Determination of New Customers	
New Customers for Year 1 Only	Yes
New Customers for Subsequent Years	No
Criteria Used for Inclusion	Utility's actual experience
Time Period Used for Adding New Customers – Number of Years	1 year
New Customer Qualification Process	N/A
Recognition of Customer Losses	No
Revenues Included in the Utility's System Extension Profitability Analysis	
Per-Customer Revenue Estimates	Yes
Rate/Revenue Adjustments Made	No
Gas Volume Adjustment to Reflect Customer's Energy Efficiency Activities	No
Capital-Related Costs Included in the Utility's System Extension Profitability Analysis	
Method to Determine the Level of Capital Investment to Connect New Customers	Actual system expansion costs Reflects depreciation expense and an after tax return on investment for the mains, service lines, meters and regulators required to connect new customers.
Cost Determination Method	Capital costs actually incurred in the particular year
Amortization Period – Number of Years	One year revenue requirement is used Assumes annual depreciation rates based on the expected lives of the investments: Mains – 41 years; Service Line – 26 years; Meters and Regulators – 22 years.
Inclusion of Replacement Costs of System Extension Facilities	No
Inclusion of Capital Reinforcement Costs for Upstream Capacity Additions	No
Inclusion of Capitalized Overhead Costs	Yes; The use of very high capitalization rates to reflect the developmental nature of this utility's operation.

Parameter	Description
Other Considerations	
Recognition of Financial Support to Customers in the Analysis	No

GAZ MÉTRO
Profitability of System Extension Projects
Gas Utility Survey Results

Utility Name: FortisBC Energy, Inc.
Location: British Columbia, Canada

Parameter	Description
System Extension Profitability Analysis Method	All applications to extend the distribution system to new customers are subject to an economic test. Test is a discounted cash flow analysis of projected revenue and costs associated with the extension.
General	
Cost of Capital Assumption	FEI's WACC
Basis for Determining the CIAC	If economic test results in P.I .< 0.8, customer can make up the shortfall with CIAC. FEI may finance CIAC amounts, and also waive amounts < $100.
Exceptions to the CIAC Basis	See System Extension Fund
Refunds to Year 1 Customers	Annual review to check the applicability of refunds. Amounts less than $100 are held in escrow until end of 5 year contributory period. Total refund cannot be greater than initial contribution.
Target Set by Individual Project or All Projects	0.8 P.I. for individual projects; 1.1 P.I. for overall project.
Use of Sensitivity Analyses	They internally will review different scenarios as deemed appropriate.
Different Methods Used Based on the Type of Project	If a project required a certificate of public convenience and necessity (i.e., >$20M) they would probably conduct a cost of service analysis. Further, if they were extending their territory to a new community/municipality they would likely need to apply to the Commission to do so.
Regulatory Requirement for LRMC/LRIC	No
Availability of Funds to Offset Below Target Profitability	System Extension Fund Pilot program. Customer may receive up to 50% of the required CIAC or up to $10,000. Available from Jan 1, 2017 thru Dec 31, 2020. Applicable to projects with P.I. between 0.2 and 0.8. Customers receiving money from the fund are not eligible for refunds.
Regulatory Review Process	FEI must periodically run a Rate Impact Analysis on its MX test and file at the BCUC. Current schedule is every 5-7 years; next is due Jun 30, 2020.

Parameter	Description
Valuation Period	
Number of Years	DCF period is 40 years (up from 20 years previously).
Basis of Valuation Period	Negotiated in regulatory filings; revised upward to better match the economic life of the assets while still being relatively conservative.
Determination of New Customers	
New Customers for Year 1 Only	No
New Customers for Subsequent Years	Yes, see below
Criteria Used for Inclusion	Estimated based on discussions between the customer and FEI, FEI's knowledge of the marketplace and FEI's history with the customer. Discussed at length in FEI's response to BCUC IR 1.2.4.
Time Period Used for Adding New Customers – Number of Years	5 year limit, unless project can point to municipal or developer plans showing a build out horizon greater than 5 years. Absolute limit is 10 years. At the end of 5 or 10 year period, all customers will have paid an equal contribution, after reconciliation & refunds.
New Customer Qualification Process	N/A
Recognition of Customer Losses	No
Revenues Included in the Utility's System Extension Profitability Analysis	
Per-Customer Revenue Estimates	Residential: Based on Residential End Use Study of existing customers. Commercial: estimated in conjunction with customers based on prior experience.
Rate/Revenue Adjustments Made	No
Gas Volume Adjustment to Reflect Customer's Energy Efficiency Activities	No adjustment is made, but energy efficiency is incentivized elsewhere in their tariff.
Capital-Related Costs Included in the Utility's System Extension Profitability Analysis	
Method to Determine the Level of Capital Investment to Connect New Customers	Based on FEI forecast. Recently, FEI has increased the amount of manual work and senior-level approvals required for larger project estimates. FEI is required to report annually to BCUC on the accuracy of its cost estimates.

Parameter	Description
Cost Determination Method	Smaller projects utilize an average per foot approach whereas larger projects rely on specific designs and estimates.
Amortization Period – Number of Years	40 years
Inclusion of Replacement Costs of System Extension Facilities	No
Inclusion of Capital Reinforcement Costs for Upstream Capacity Additions	Yes – include a factor for system improvements that gets set based on planning group annually.
Inclusion of Capitalized Overhead Costs	Yes; overhead rate was a flat 23% across all projects in 2014. Subsequently, BCUC approved a sliding scale overhead rate for projects larger than $25,000. Higher CAPEX = lower overhead rate.
Other Considerations	
Recognition of Financial Support to Customers in the Analysis	No

GAZ MÉTRO
Profitability of System Extension Projects
Gas Utility Survey Results

Utility Name: Union Gas Limited
Location: Ontario, Canada

Parameter	Description
System Extension Profitability Analysis Method	Economic Evaluation Model (EEM) which is a discounted cash flow (DCF) model.
General	
Cost of Capital Assumption	Incremental after-tax cost of capital based on the prospective capital mix, debt, and preference share cost rates, and the latest approved rate of return on common equity.
Basis for Determining the CIAC	The Ontario Energy Board's 188 Decision requires a standardized DCF analysis to be performed. The OEB set the minimum threshold for the Rolling Project Portfolio at 1.0 P.I. and the minimum for an individual project to 0.8. The OEB also set the minimum threshold for the Investment Portfolio to 1.1 which included all distribution business projects necessary to attach customers of all rate classes in a given test year.
Exceptions to the CIAC Basis	Union must provide at no cost a service line of 30 meters in length to connect a residential customer. A 1.0 P.I. is required for projects where no further growth is anticipated or a dedicated line is required or for all non-residential projects. Services over 30 meters in length will require the prior agreement of the customer to pay an "excess charge" of $45.00 per meter.
Refunds to Year 1 Customers	No
Target Set by Individual Project or All Projects	See above; standards apply to both individual projects and all project portfolios.
Use of Sensitivity Analyses	No
Different Methods Used Based on the Type of Project	No
Regulatory Requirement for LRMC/LRIC	No
Availability of Funds to Offset Below Target Profitability	No
Regulatory Review Process	The regulator reviews each utility's expansion activities on an individual project and portfolio basis. Utilities are required to forecast the rate impacts of their expansion plans and present them in rate case filings on a prospective test year basis.

Parameter	Description
Valuation Period	
Number of Years	40-year customer revenue horizon; or 20 years for large volume customers.
Basis of Valuation Period	Regulatory determination (in 1998)
Determination of New Customers	
New Customers for Year 1 Only	No
New Customers for Subsequent Years	10-year customer attachment horizon
Criteria Used for Inclusion	A forecast is required for customer attachments during the Customer Attachment Horizon for each project. • Mass market customers – no specific usage forecast required; • Larger customers – customer survey with the sales forecast reviewed by the regulator.
Time Period Used for Adding New Customers – Number of Years	10 years
New Customer Qualification Process	A water heater or primary heat source.
Recognition of Customer Losses	No
Revenues Included in the Utility's System Extension Profitability Analysis	
Per-Customer Revenue Estimates	Estimated by utility reflecting the mix of customers to be added.
Rate/Revenue Adjustments Made	No
Gas Volume Adjustment to Reflect Customer's Energy Efficiency Activities	No
Capital-Related Costs Included in the Utility's System Extension Profitability Analysis	
Method to Determine the Level of Capital Investment to Connect New Customers	Utilities are required to include common elements when calculating capital costs, including: • Estimate of all costs directly associated with the attachment of the forecasted customer additions (including distribution mains, customer stations, distribution stations, land, and land rights); • An estimate of the incremental overheads applicable to distribution expansion at the portfolio level; and • An estimate of the normalized system reinforcement costs.
Cost Determination Method	The "incremental" investment needed over the 10-year planning horizon to serve the new customers.

Parameter	Description
Amortization Period – Number of Years	Same as valuation period
Inclusion of Replacement Costs of System Extension Facilities	No For example, meter replacement after 25 years is not reflected as an additional capital cost because such costs are considered to be recurring costs that are included and recovered in the utility's current distribution rates.
Inclusion of Capital Reinforcement Costs for Upstream Capacity Additions	Case-by-case basis For any particular project, if the additional capacity needs of new customers over the 10-year planning horizon requires the reinforcement of the utility's upstream T&D system, those additional capital costs will be included in the DCF analysis.
Inclusion of Capitalized Overhead Costs	Yes
Other Considerations	
Recognition of Financial Support to Customers in the Analysis	Utility can finance customer's CIAC.

After petitioning the Commission and failing to secure approval to allow Union to collect revenue from existing customers to subsidize the costs of future expansions, Union has filed before the Commission a request to charge a $0.23/m^3 System Expansion Surcharge (SES) on four specific proposed projects to extend gas service to previously unserved communities. The charge will be levied on the expansion customers only until the P.I. of each project reaches 1.0, which is expected to occur at different times for each project (ranging from 2029 to 2057). Union also proposes to treat any upfront contributions from the provincial government or the communities themselves as a CIAC, and future contributions as revenue for DCF modeling purposes.

GAZ MÉTRO
Profitability of System Extension Projects
Gas Utility Survey Results

Utility Name: Cascade Natural Gas
Location: Washington State

Parameter	Description
System Extension Profitability Analysis Method	Cascade offers a generous allowance based on the Perpetual Net Present Value (PNPV) of adding the customer, which is the customer's expected annual net revenue divided by its WACC. Customer pays for construction costs above the allowance.
General	
Cost of Capital Assumption	WACC (7.35%)
Basis for Determining the CIAC	Based on cost of extension – identified allowance based on average use of customers (RS and C) use NPV and due it on individual basis – evaluating annual usage – get allowance if needed based on CAIC Amount Due = (Main Extension Costs – Allowance) * Federal Income Taxes Residential allowance is $3,255 Commercial allowance is $12,350 Allowance applies to both main extension and service line. Allowance calculated using PNPV calculation. Interruptible, industrial, large volume, and transport customers may receive an allowance up to the sum of annual basic service charges plus expected margin divided by WACC. Hoping not to have to charge a CIAC. Cascade is in investment mode. Also a lot of rate cases
Exceptions to the CIAC Basis	When looking at a main, Cascade can factor in what the future load looks like. Can reduce cost to first customer
Refunds to Year 1 Customers	Refunds are no longer offered for new customers. Refunds previously agreed upon prior to Sept 1, 2016 are still honored. Refunds are hard to track. Less need for refunds since Cascade is taking into account future growth. Tried to get rid of refund policy in Oregon but was unsuccessful
Target Set by Individual Project or All Projects	Each project
Use of Sensitivity Analyses	No
Different Methods Used Based on the Type of Project	No
Regulatory Requirement for LRMC/LRIC	No
Availability of Funds to Offset Below Target Profitability	No
Regulatory Review Process	Part of conditions on getting this policy was to provide some annual reporting. The Commission is generally in favor of

Parameter	Description
	extending into un served areas so they want to make sure they are getting that.
Valuation Period	
Number of Years	N/A - Perpetual
Basis of Valuation Period	The methodology produces the maximum main extension allowance that is economically viable for the company
Determination of New Customers	
New Customers for Year 1 Only	No
New Customers for Subsequent Years	They have flexibility to decide how far out to consider future customers. Based on discussion with planners. "Best you know at the time you made the decision"
Criteria Used for Inclusion	Determined by the planner and designer on the project
Time Period Used for Adding New Customers – Number of Years	Not written up in the tariff and they have flexibility. If county planning department was assuming growth they could rely – best they knew at the time they made the decision.
New Customer Qualification Process	If they bring on a large industrial customer – anchor tenant – internally they had a problem with this policy since it's a 11.5 year simple payback so they were afraid customers wouldn't be around. Yes customers come and go but facility stays there so they don't' see a lot of risk – use is still there even if business change owners.
Recognition of Customer Losses	No. They utilize the decoupled usage since they have decoupling in place. Customer installing a BBQ grill is treated the same as a customer with more extensive gas usage
Revenues Included in the Utility's System Extension Profitability Analysis	
Per-Customer Revenue Estimates	For interruptible, industrial, transport, or large volume, customer must fill out a customer load summary. Ultimately up to Cascade to estimate. To determine eligibility for allowance, Residential and Commercial customers may also be required to fill out a customer load summary Assumes current average use per customer (30 year weather normalized; last 5 years of usage), updated every rate case. Average use * expected customers (over reasonable time period)
Rate/Revenue Adjustments Made	None (customer charge + margin). Margin = Total Revenue less gas costs (incl transport & delivery). Base rates.
Gas Volume Adjustment to Reflect Customer's Energy Efficiency Activities	No but the amount is updated every rate case to reflect average usage

Parameter	Description
Capital-Related Costs Included in the Utility's System Extension Profitability Analysis	
Method to Determine the Level of Capital Investment to Connect New Customers	Just include the capital costs. Meter and meter provided for by company and not in calculations. Build out estimate on case by case basis and use actual estimates as best you can; up to their discretion on when to usage average costs vs. specific estimate.
Cost Determination Method	Apply price for a foot – embedded cost of service so no consideration of LRMC or LRIC.
Amortization Period – Number of Years	N/A
Inclusion of Replacement Costs of System Extension Facilities	No
Inclusion of Capital Reinforcement Costs for Upstream Capacity Additions	In general we would include any upstream costs in rate base – but if it is a large transport customer they would look at what it would take to just serve that customer or are there benefits to the rest of the system.
Inclusion of Capitalized Overhead Costs	Yes
Other Considerations	
Recognition of Financial Support to Customers in the Analysis	Don't credit anything – they do have a conversion program but it is independent of the main extension program. For interruptible, industrial, transport, or large volume, Cascade can allow customer to pay costs over time via a facility charge rather than up front

GAZ MÉTRO
Profitability of System Extension Projects
Gas Utility Survey Results

Utility Name: Chesapeake Utilities (Delaware Division)
Location: Delaware

Parameter	Description
System Extension Profitability Analysis Method	For residential, an Internal Rate of Return Model is used; for commercial & industrial, a 6 times net revenue test is used. If the IRR of the revenue test is less than the WACC then they require a contribution from the customer.
General	
Cost of Capital Assumption	Weighted Average Cost of Capital (WACC) Based on company's capital structure, cost of equity, and cost of debt in Chesapeake's most recent base rate proceeding before the Commission. For southeastern Sussex County, cost of long term debt is set at 3.75%
Basis for Determining the CIAC	Main extensions: IRR model used to determine if financial guarantees are required from the customer Service main extensions: If service line exceeds 75 feet in length, Chesapeake may only spend 6x expected net revenue (and customer must make up remainder).
Exceptions to the CIAC Basis	No
Refunds to Year 1 Customers	Financial guarantees can take the form of CIAC, Customer Advance, Letter of Credit, or other. Customer Advances are subject to refund for up to 6 years depending on agreement between company and customer
Target Set by Individual Project or All Projects	Set for each individual project. In expansion areas they have to file after 3 years in that area to show that they are hitting the required IRR for each project.
Use of Sensitivity Analyses	Internally they may look at difference scenarios.
Different Methods Used Based on the Type of Project	No
Regulatory Requirement for LRMC/LRIC	No
Availability of Funds to Offset Below Target Profitability	No
Regulatory Review Process	The 2013 Settlement contained a provision (P.9) under which, at the next base rate proceeding, the Company would bear 50% of the shortfall if the aggregated IRRM of all expansion projects fell short of the target. Such a provision provides incentives for the Company to 16 PSC Docket No. 15-1734, Order NO. 8982 Cont'd select wisely, control costs and build revenues, and it provides ratepayers some protection from the potential cost of uneconomic expansions "

Parameter	Description
Valuation Period	
Number of Years	40 years
Basis of Valuation Period	Not described
Determination of New Customers	
New Customers for Year 1 Only	For existing customer developments, based on number of customers intending to convert to natural gas and have signed an application with Chesapeake For new customer developments, based on estimated number of lots that have been approved for development. Buildout period (1-6 years) varies based on number of customers.
New Customers for Subsequent Years	More discretion of taking into account future revenues in non-expansion areas, as they can utilize customer surveys and forecasts in non-expansion areas. Within expansion areas they require a written subscription.
Criteria Used for Inclusion	See 'New Customers for Subsequent Years' section above.
Time Period Used for Adding New Customers – Number of Years	Depends on project but is generally between 1-6 years.
New Customer Qualification Process	See 'New Customers for Subsequent Years' section above.
Recognition of Customer Losses	No
Revenues Included in the Utility's System Extension Profitability Analysis	
Per-Customer Revenue Estimates	In southeastern Sussex County expansion area: based on potential customer's consumption on a case-by-case basis. For all other customers, based on margin per customer as determined by the Commission (for the applicable rate schedule)
Rate/Revenue Adjustments Made	None
Gas Volume Adjustment to Reflect Customer's Energy Efficiency Activities	No
Capital-Related Costs Included in the Utility's System Extension Profitability Analysis	
Method to Determine the Level of Capital Investment to Connect New Customers	Determined on a project-by-project basis. In 2017 IRRM filing, reported that typical residential service and meter installation in 2016 was $1,225 per customer. Residential service cost - $966 Residential meter cost - $170 Meter Installation cost - $89
Cost Determination Method	Smaller projects utilize a per foot average costs and large projects utilize a more detailed estimate from their design and estimation software.
Amortization Period – Number of Years	20 years

Parameter	Description
Inclusion of Replacement Costs of System Extension Facilities	No
Inclusion of Capital Reinforcement Costs for Upstream Capacity Additions	They have discretion to do this but the question does not come up often and it would have to be very specific to the extension project. The default position is for these costs to be in general rate base as they typically support all customers.
Inclusion of Capitalized Overhead Costs	Yes, indirect overhead rate of 26% applies to all non-contractor related cost components of installation costs.
Other Considerations	
Recognition of Financial Support to Customers in the Analysis	No

GAZ MÉTRO
Profitability of System Extension Projects
Gas Utility Survey Results

Utility Name: Columbia Gas (NiSource Inc.)
Location: Kentucky, Maryland, Massachusetts, Ohio, Pennsylvania and Virginia

Parameter	Description
System Extension Profitability Analysis Method	For residential customers, a set footage extension allowance with deposit or contribution required for larger projects in which NPV is negative. For commercial & industrial, same policy, usually without the footage allowance (depending on the state). The economic model utilized is universal across the NiSource companies (i.e., Columbia Gas companies operate in six jurisdictions) except for NIPSCO in Indiana. Differences in application or policies between the six Columbia Gas companies are noted below (e.g., set footage allowance differs in each state).
General	
Cost of Capital Assumption	The required return is set to their most recent approved WACC. If rate case was settled they calculate an implied WACC based on settlement.
Basis for Determining the CIAC	Residential: Customer entitled to a set footage allowance* for main and or service main extensions. For projects larger than the allowance, customer must pay a contribution equal to the difference between the amount of capital that can be justified on a project (measured by expected revenues) and the minimum capital investment required to serve the customer. Commercial & Industrial: Same as residential, usually with no footage allowance (depending on the state) Subject to minimum use agreements or other refundable deposits if company is uncertain on future gas consumption * In VA: 150 feet In PA: 150 feet In MD: 150 feet (50 feet for non-heating residential) In OH: 100 feet In KY: 100 feet
Exceptions to the CIAC Basis	In some states such as Pennsylvania, if deposit is required, Columbia Gas may reduce or eliminate the requirement if they believe the service will benefit other customers within a reasonable period of time. In Virginia, a customer with an uneconomic project may choose to have its project included in the System Expansion Program (SEP) subject to the MAIN rider. Participants in applicable areas are charged a fixed amount of $6.63/month for 240 months. This applies only to new residential customers that would have had a CIAC under $4300.

Parameter	Description
Refunds to Year 1 Customers	Depends on state. In most states, deposits are refundable, contributions are not. Refundable annually for a set time period, can be 7 years, up to 10 years depending on state. Some states allow the LDC and the customer to negotiate refund provisions. Generally, residential refunds are based on number of connections subsequently made to the line; commercial & industrial refunds are based on throughput. No refunds in Massachusetts.
Target Set by Individual Project or All Projects	Requirement to meet WACC is set for each project.
Use of Sensitivity Analyses	Internally will review different scenarios
Different Methods Used Based on the Type of Project	Method remains the same but time horizon may be changed based on type of project (see 'Number of Years' below).
Regulatory Requirement for LRMC/LRIC	No
Availability of Funds to Offset Below Target Profitability	No. They do have funds in some states to offset 'betterments' (i.e., upstream reinforcement or integrity investments).
Regulatory Review Process	In MD, PA, and VA they are required to file a report to monitor activity – how many customers are getting free service line, how many use tap and save. In general the regulator wants to see if filed activity level used for investment planning is matching actual level. There are also prudence reviews during rate cases; typically focused on the larger main extension projects. This review is very detailed in MA and includes a pre and post profitability analysis during rate cases.
Valuation Period	
Number of Years	Utilize 40 years for residential projects and will reflect different time periods for commercial and industrial projects. Institutional commercial (e.g., university) they use 30 years Retail commercial is closer to 15 years Industrial is usually no more than 7 For large developments, they may require a main extension agreement which can impact the time period utilized in the analysis (i.e., depends on the time period of customers expected to join the development).
Basis of Valuation Period	Certainty of revenues from different end uses.
Determination of New Customers	
New Customers for Year 1 Only	No
New Customers for Subsequent Years	Yes – they can include subsequent years. Model can take into account additional capital costs and additional revenues in out years based on expected customer additions and costs (e.g., in the case of a residential development).
Criteria Used for Inclusion	Various considerations are utilized by the Utility.

Parameter	Description
Time Period Used for Adding New Customers – Number of Years	Typically use 3 years but they may use 5 years but it is at the discretion of the utility.
New Customer Qualification Process	N/A
Recognition of Customer Losses	No, but they do account for inactivity over time by including a revenue reduction of approximately 2.5% annually due to inactivity of meter over time. If within a residential development they will have a 2-3 month shutoff period in the first 36 months to account for the time the house moves from being built to sold and occupied by the new owner.
Revenues Included in the Utility's System Extension Profitability Analysis	
Per-Customer Revenue Estimates	Typically utilize square footage of residence and the particular base load appliances. The assumed heating load per square foot varies by states. In Virginia: Based on standard usage factors on file with the Commission. In Virginia: Examples: Heat Load = specific heat factor x sq footage. Single family new construction SHF = 0.024, multi-family new construction = 0.020, conversion = 0.026 Load credits beyond heat load: tank water heating = 21 DTH/year; tankless = 15 Dth/year
Rate/Revenue Adjustments Made	Only take into account customer charge and base rate charge so that certain riders are not in the model (e.g., uncollectibles, purchased gas, and a few others). In Virginia: "currently authorized rates, excluding the purchased gas charge".
Gas Volume Adjustment to Reflect Customer's Energy Efficiency Activities	No
Capital-Related Costs Included in the Utility's System Extension Profitability Analysis	
Method to Determine the Level of Capital Investment to Connect New Customers	For residential they utilize averages per foot of installed main as they have blanket contracts with their contractors. They will take into account specific design and construction requirements if particular circumstances dictate. Will build up a specific project quotes for larger installations serving non-residential customers.
Cost Determination Method	Blanket contracts in place with contractors and/or specific estimates from internal design software based on current cost assumptions.
Amortization Period – Number of Years	In Massachusetts, 20 years.
Inclusion of Replacement Costs of System Extension Facilities	No
Inclusion of Capital Reinforcement	The inclusion of upstream costs depends on the state – in general

Parameter	Description
Costs for Upstream Capacity Additions	if the extension is clearly creating the need for that investment then it would be included in the economic test. However if it is more about reinforcement for existing or future customers it would be in base rates. The review of this is specific to each state.
Inclusion of Capitalized Overhead Costs	They do include capitalized overheads on capital portion such as supervision, general administrative, etc. They also include taxes and depreciation for capital investment.
Other Considerations	
Recognition of Financial Support to Customers in the Analysis	No. In PA they have a pilot program titled Tap and Save that allows for customers to pay for their main extension over a period of 20 years rather than the upfront payment.

GAZ MÉTRO
Profitability of System Extension Projects
Gas Utility Survey Results

Utility Name: Interstate Power and Light
Location: Iowa

Parameter	Description
System Extension Profitability Analysis Method	IPL will extend its mains if anticipated net revenue is sufficient to justify the expenditure. IPL must take into consideration the total cost to serve the customer and ensure that it will not cast a burden on existing customers. The gas utilities in Iowa are currently in a rulemaking process whereby they are proposing an economic test with 20 years of forecasted revenue in rural areas, subject to certain capital spending limits on a portfolio basis. The proposed rule would allow utilities to add provisions to their tariff to provide this alternative method for approving projects and calculating CIAC. AS currently written, any projects going forward under these rules would acquire preapproval from the Iowa Utilities Board (Chapter 19. Docket # RMU2016-0007).
General	
Cost of Capital Assumption	No discounting used
Basis for Determining the CIAC	Typically the requirement, which is set by the administrative code in Iowa, is if the first 3 years of revenues is greater than or equal to the capital investment than no CIAC is needed. They can extend the 3 years to 5 in certain circumstances. For gas service lines, nonrefundable CIAC required for lines greater than 100 feet for polyethylene pipe or 50 feet for other pipe. CIAC is calculated based on the ratio of excess service line to the total service line time the total estimated service line cost
Exceptions to the CIAC Basis	Outside of the ability extend the revenues up to 5 years, which requires annual reporting there are no exceptions.
Refunds to Year 1 Customers	Yes, for mains only (not service lines) based on a pro rata share of future attachments for a period of 10 years. To be considered for a refund, the attachment must be a directly connected service line from the first main extension.
Target Set by Individual Project or All Projects	Individual project
Use of Sensitivity Analyses	N/A
Different Methods Used Based on the Type of Project	For projects where IPL can prove there is a competing service, the advance for construction is calculated as estimated construction cost less 5x estimated base revenue
Regulatory Requirement for LRMC/LRIC	No
Availability of Funds to Offset Below Target Profitability	No funds available

Parameter	Description
Regulatory Review Process	IPL is required to file an annual report on all extensions where the analysis uses more than 3 years of revenues.
Valuation Period	
Number of Years	N/A
Basis of Valuation Period	Aligned with electric utility business.
Determination of New Customers	
New Customers for Year 1 Only	Yes; Only utilize customers that are signed up for service as of the date the construction is to be completed. They do not forecast any future customers.
New Customers for Subsequent Years	No
Criteria Used for Inclusion	Signed up for service to be received when construction is completed.
Time Period Used for Adding New Customers – Number of Years	N/A
New Customer Qualification Process	See above 'Criteria Used for Inclusion'
Recognition of Customer Losses	No
Revenues Included in the Utility's System Extension Profitability Analysis	
Per-Customer Revenue Estimates	Based on similarly situated customers. Residential customers regardless of size receive same revenue credit. For other customers, look at similar customers (i.e. if it's a dry cleaner, look at other dry cleaners). For customers they are unfamiliar with, ask for input from customer. May require an agreement for amount of natural gas to be used. Contract may require minimum bill
Rate/Revenue Adjustments Made	No. Use the same rate going forward as is currently in place. They may ramp up revenues if customer is expecting increased usage over the first few years of service.
Gas Volume Adjustment to Reflect Customer's Energy Efficiency Activities	No
Capital-Related Costs Included in the Utility's System Extension Profitability Analysis	
Method to Determine the Level of Capital Investment to Connect New Customers	Varies by project size – up to ¼ mile they'll use avg. cost per foot anything longer they'll design it and engineer it for specific considerations in their design/estimation software.
Cost Determination Method	Average cost or specific cost estimate. See item directly above.
Amortization Period – Number of Years	N/A
Inclusion of Replacement Costs of System Extension Facilities	No

Parameter	Description
Inclusion of Capital Reinforcement Costs for Upstream Capacity Additions	If they need to do some additional 'upsizing' they will build those costs into their analysis but they won't charge the customer as the Company will incur the cost and role it into general base rates. Depending on size of project they have internal review project to vetting those costs and company contributions
Inclusion of Capitalized Overhead Costs	Yes; they typically include A&G, Engineering & supervision, internal/external labor. Inclusion of overheads depends on project, and if costs are material.
Other Considerations	
Recognition of Financial Support to Customers in the Analysis	No

GAZ MÉTRO
Profitability of System Extension Projects
Gas Utility Survey Results

Utility Name: Unitil Corporation
Location: Maine, Massachusetts and New Hampshire

Parameter	Description
System Extension Profitability Analysis Method	In cases where the proposed project does not meet the criteria for a standard allowance, a discounted cash flow analysis is run, requiring Unitil to show the project can recover its costs or require a customer to make up the shortfall with a CIAC.
General	
Cost of Capital Assumption	WACC. Last approved cost of common equity, current cost of debt, capital structure.
Basis for Determining the CIAC	If project revenues do not meet costs, discounted at WACC, customer must pay a non-refundable CIAC to make up the difference. Implied P.I. of 1.0
Exceptions to the CIAC Basis	Have never gone external to company to get approval for project that is under their cost of capital No customer contributions are required for residential service connections 100 feet or less (called the Standard Offer Service, "SOS") [See also the TAB program at the bottom of this doc] For these residential customers, DCF analysis is based on incremental footage from the 100 ft allowance
Refunds to Year 1 Customers	Yes, for a period of 5 years (post-construction), if previously unaccounted for customers would have the effect of lowering the calculated CIAC for the initial customers, a refund may be given
Target Set by Individual Project or All Projects	All projects
Use of Sensitivity Analyses	No
Different Methods Used Based on the Type of Project	Targeted Area Build-Out (TAB) Program – Currently applicable in Sanford, Maine. Northern Utilities may, with Commission approval, declare an area to be a Targeted Area Build-out (TAB) area. Customers within the TAB area will pay a set TAB charge (varies from \$0.0306/ccf to \$0.2154/ccf by rate schedule) during an initial 10 year period, after which the charge will not be assessed to existing or new customers. TAB charges are not subject to refund. TAB charges are in lieu of paying CIAC. TAB Charge is calculated using DCF analysis similar to that required of other main extensions.
Regulatory Requirement for LRMC/LRIC	No
Availability of Funds to Offset Below Target Profitability	No

Parameter	Description
Regulatory Review Process	No filing or notification requirements. Regulators have raised some issue in base rate proceedings.
Valuation Period	
Number of Years	20 years (residential); 10 years (commercial and industrial) The duration begins after the last year of construction.
Basis of Valuation Period	Residential customers are more homogenous and have a lower risk profile. Unitil believes that longer evaluation periods provide a disincentive to signing up new customers because it decreases the CIAC, which makes the annual rate of returns more negative in the early years of a project, creating the need for Unitil to absorb the gap.
Determination of New Customers	
New Customers for Year 1 Only	Will consider beyond year 1 in limited circumstances, see below
New Customers for Subsequent Years	Tariff provides provisions to impute revenue or to estimate future revenues for a given area. They have done this before in "limited circumstances."
Criteria Used for Inclusion	Will consider residential customers to be added in the near future. Would typically require C&I customers to have a signed contract for inclusion because they are riskier
Time Period Used for Adding New Customers – Number of Years	[Appears it is likely relatively short time period that they will consider new customers, and this is infrequently done]
New Customer Qualification Process	Require a signed contract before main/service is extended.
Recognition of Customer Losses	No
Revenues Included in the Utility's System Extension Profitability Analysis	
Per-Customer Revenue Estimates	Business development staff develops an estimated load based on square footage, type of furnace, production load, (available information). If not available, historical, weather normalized customer class average is used.
Rate/Revenue Adjustments Made	No anticipated rate adjustments are incorporated in the model due to uncertainty. Model uses currently effective rates
Gas Volume Adjustment to Reflect Customer's Energy Efficiency Activities	No
Capital-Related Costs Included in the Utility's System Extension Profitability Analysis	
Method to Determine the Level of Capital Investment to Connect New Customers	Actual incremental dollar outflow. Excludes overheads (engineering, operations, & corporate). It is an unloaded capital cost

Parameter	Description
	Includes: Regulator, service, main extension (meter cost not included – considered an “in-stock” expense) Distribution costs are on an embedded basis, so this methodology is consistent with rate design
Cost Determination Method	See above
Amortization Period – Number of Years	N/A
Inclusion of Replacement Costs of System Extension Facilities	No
Inclusion of Capital Reinforcement Costs for Upstream Capacity Additions	Case by case basis. Historically they have not included these costs. Generally recovered through base rate filing
Inclusion of Capitalized Overhead Costs	Excludes overheads (engineering, operations, & corporate)
Other Considerations	
Recognition of Financial Support to Customers in the Analysis	No